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January 27, 2011

Ms. Gwendolyn Keyes Fleming
Regional Administrator
U.S. EPA, Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303

RE: Redesignation of Kentucky portion of the Cincinnati-Hamilton OH-KY-IN fine particulate nonattainment area

Dear Ms. Fleming:

Enclosed for your consideration is the final revision to Kentucky's State Implementation Plan to redesignate the Kentucky portion of the Cincinnati-Hamilton OH-KY-IN $PM_{2.5}$ nonattainment area (Boone, Campbell, and Kenton counties) as attainment for the $PM_{2.5}$ National Ambient Air Quality Standard.

A public hearing to receive comments on this revision was held December 15, 2010, at 6:00 p.m. in the Conference Room of the Northern Kentucky Area Development District (NKADD), 22 Spiral Drive, Florence, Kentucky. A copy of the public hearing notice and the statement of consideration are included in this submittal.

Ohio and Indiana are making separate redesignation requests for their respective portions of the metropolitan area and have submitted those demonstrations to U.S. EPA, Region 5.

Your prompt consideration of this request is appreciated. If you have any questions or comments concerning this matter, please contact Andrea Smith with the Division for Air Quality at (502) 564-3999.

Sincerely Yours,

Leonard K. Peters
Secretary

Henry C.A. List
Deputy Secretary

Enclosures
c: Beverly Banister
Dick Schutt

REDESIGNATION REQUEST AND MAINTENANCE PLAN FOR KENTUCKY COUNTIES

LOCATED WITHIN THE

CINCINNATI-HAMILTON, OH-KY-IN, MSA 1997 ANNUAL PM2.5 NONATTAINMENT AREA

Prepared by
KENTUCKY
DIVISION FOR AIR QUALITY

Submitted by
ENERGY AND ENVIRONMENT CABINET
FINAL
January 24, 2011

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INTRODUCTION

The Cincinnati-Hamilton area is designated as a fine particulate ($PM_{2.5}$) Nonattainment Area for the annual standard of the 1997 National Ambient Air Quality Standard (NAAQS) of 15.0 micrograms per cubic centimeter (ug/m^3) for $PM_{2.5}$. This document is intended to support Kentucky's request that the Kentucky portions of the Cincinnati-Hamilton area be redesignated from nonattainment to attainment for the annual standard. In addition, the States of Ohio and Indiana also intend to submit requests for their respective portions of the Cincinnati-Hamilton area. Copies of the Ohio and Indiana submittal can be found in *Appendix H*.

In accordance with section 110(k) of the Clean Air Act Amendments of 1990, Kentucky's request to amend the State Implementation Plan (SIP) is based on the most recent three (3) years of monitoring data showing no additional violations of the annual standard for the 2007-2009 time period, and a calculated $PM_{2.5}$ design value for 2007-2009 data that is attaining the NAAQS. This submittal does not address attainment or designation issues regarding the 24-hour standard. Permanent and enforceable reductions in fine particulate emissions have occurred and emission projections demonstrate that the 2008 attainment year emission levels in this area will not be exceeded during the next 10 years.

This redesignation request was prepared in accordance with the U.S. EPA memorandum from John Calcagni, June 23, 1992, "Subject: Processing of SIP Submittals," and the U.S. EPA memorandum from John Calcagni, September 4, 1992, "Subject: Procedures for Processing Requests to Redesignate Areas to Attainment," and the U.S. EPA memorandum from William Harnett, October 2, 2007, "Subject: Guidance on SIP Elements Required Under Sections

110(a)(1) and (2) for the 1997 8-hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards" (*Appendix A).*

BACKGROUND

The Clean Air Act Amendments of 1990 (CAA) establishes a process for air quality management through the NAAQS. Area designations are required after promulgation of a new or revised NAAQS. On July 18, 1997, the U.S. EPA revised the NAAQS particulate standard to add new standards for $PM_{2.5}$, using $PM_{2.5}$ as the indicator pollutant. The U.S. EPA established health-based (primary) annual and 24-hour standards for $PM_{2.5}$ (*Appendix B*, 62 FR 38652*).* The welfare-based (secondary) standards for both were established as identical to the primary standard. Secondary standards are designed to protect against major environmental effects of $PM_{2.5}$ such as visibility impairment, soiling, and materials damage.

The annual standard is a level of 15 micrograms per cubic meter (ug/m^3), based on the 3-year average of the annual mean $PM_{2.5}$ concentrations. The U.S. EPA established the standard based on evidence from numerous health studies demonstrating that serious health effects are associated with exposures to elevated levels of $PM_{2.5}$. The U.S. EPA and State air quality agencies initiated the monitoring process for the $PM_{2.5}$ NAAQS in 1999, and deployed all air quality monitors by January 2001.

Airborne particles generally less than or equal to 2.5 micrometers in diameter are considered to be "fine particles". "Primary" particles are emitted directly into the air as a solid or liquid particle (e.g. elemental carbon from diesel engines or fire activities, or condensable organic

particles from gasoline engines). "Secondary" particles (e.g. sulfate and nitrate) form in the atmosphere as a result of various chemical reactions. Five main types of pollutants contribute to fine particle concentrations: direct $PM_{2.5}$ emissions; sulfur dioxide (SO_2); nitrogen oxides (NO_x); ammonia (NH_3); and volatile organic compounds (VOCs).

However, the effect of reducing emissions of each of these pollutants varies area by area, depending on the fine particle composition, emission levels, and other area-specific elements. Kentucky's main $PM_{2.5}$ components are primary particles, SO_2, and NO_x, which were included in the attainment demonstration analysis. Volatile organic compounds and ammonia were not included in the analysis since they were not part of Kentucky's current attainment strategy for $PM_{2.5}$. Note however that VOC controls have been implemented in northern Kentucky for ozone attainment as described in the SIP for resignation to attainment (*Appendix B*, 75 FR 47218).

The final rule for implementation published April 25, 2007, established policy for evaluating and controlling sources of these emissions (*Appendix B*, 72 FR 20586). $PM_{2.5}$, SO_2, and NO_x must be evaluated for emission reduction measures in all nonattainment areas. VOCs and NH_3 are not required to be evaluated for emission reduction measures in each area unless the state or the U.S. EPA demonstrates that these pollutants significantly contribute to $PM_{2.5}$ concentrations in a specific area.

The $PM_{2.5}$ NAAQS were challenged by numerous litigants and in May 1999, the U.S. Court of Appeals for the D.C. Circuit issued a decision remanding, but not vacating, the standards. In *American Trucking Association v. the U.S. EPA*, 175 F.3d 1027, 1047-48, on rehearing 195 F.3d

4 (D.C. Circuit, 1999), the U.S. EPA sought review of two aspects of that decision in the U.S. Supreme Court. The Supreme Court upheld the $PM_{2.5}$ standards in the *U.S. EPA v. American Trucking Association*, 531 U.S. 457 (S. Ct., 2001).

In March 2002, the D.C. Circuit Court rejected all remaining challenges to the $PM_{2.5}$ standards in *American Trucking Association v. the U.S. EPA*, 283 F.3d 355 (D.C. Circuit, 2002). Since final resolution of the litigation over the $PM_{2.5}$ NAAQS, the U.S. EPA has been acting to implement the standards.

The process for designating areas following promulgation of a new or revised NAAQS is contained in section 107(d)(1) of the CAA. The Transportation Equity Act for the 21st Century (TEA-21) extended the time for the U.S. EPA to initiate the designations process for the $PM_{2.5}$ NAAQS until three (3) calendar years of air quality data, measured at Federal Reference Method monitors, were gathered.

In April 2003, the U.S. EPA issued designation guidance concerning how to determine the boundaries for $PM_{2.5}$ nonattainment areas. The guidance provided that the U.S. EPA would use the three (3) most recent calendar years of monitoring data for $PM_{2.5}$ to determine each county's designation. The 2003 guidance memorandum described nine (9) factors that the U. S. EPA would consider in determining appropriate nonattainment area boundaries: (1) emissions and air quality in adjacent areas; (2) air quality in potentially included versus excluded areas; (3) population density and degree of urbanization including commercial development in included versus excluded areas; (4) traffic and commuting patterns; (5) expected growth (including extent,

pattern, and rate of growth); (6) meteorology (weather/transport patterns); (7) geography/topography (e.g. mountain ranges or other air basin boundaries); (8) jurisdictional boundaries (e.g. counties, air districts, reservations, etc.); and (9) level of existing controls on emission sources.

The U.S. EPA issued final designations for areas violating the 1997 standard on December 17, 2004. Designations were published (*Appendix B*, 70 FR 944) on January 5, 2005. On April 5, 2005 the U.S. EPA issued a supplemental notice which changed the designation status of eight (8) areas from nonattainment to attainment based on newly updated 2002-2004 air data.

Thus designations were finalized in the FR published January 5, 2005 and designation modifications were finalized (*Appendix B*, 70 FR 19844) and published April 14, 2005. The effective date for all designations was April 5, 2005.

In accordance with Section 107(d)(1) of the CAA, the U.S. EPA designated the Cincinnati-Hamilton area to be nonattainment for the annual $PM_{2.5}$ NAAQS. The current nonattainment area is located in northern Kentucky and includes the following counties: Boone, Campbell, and Kenton in Kentucky; Butler, Clermont, Hamilton, and Warren in Ohio; and Dearborn (partial nonattainment of Lawrenceburg Township only) in Indiana.

The nonattainment designation for an area starts the process whereby a State must develop an implementation plan that includes, among other things, an attainment demonstration showing how it will attain the ambient standards by the attainment dates required under the CAA. Under

section 172(b) of the CAA, States have up to three (3) years after the U.S. EPA's final designations to submit their SIPs to the U.S. EPA.

Section 172(a)(2) of the CAA requires States to attain the standard as expeditiously as practicable, but within five (5) years of designation. The U.S. EPA Administrator can extend an area's attainment date 1-5 years based on the severity of the nonattainment problem or the feasibility of implementing control measures.

Kentucky submitted an attainment demonstration for the Kentucky portion of the annual $PM_{2.5}$ nonattainment area in November 2008, using numbers modeled by the Visibility Improvement State and Tribal Association of the Southeast and the Association of Southeastern Integrated Planning (VISTAS/ASIP). That submittal provided documentation that each state in the nonattainment area would attain the annual $PM_{2.5}$ standard by April 5, 2010.

Ohio and Indiana also submitted attainment demonstrations for their $PM_{2.5}$ nonattainment portions; both States' SIP submittals relied on modeling provided by the Lake Michigan Air Director's Consortium (LADCO).

To date, no action has been taken by the U.S. EPA on those attainment demonstration submittals, primarily due to the uncertainty at that time over the Clean Air Interstate Rule (CAIR), the credit for emission reductions granted under that program, and the status of any future CAIR replacement rule.

The "Clean Air Fine Particle Implementation Rule" (*Appendix B*, 72 FR 20586) was issued March 10, 2005 to address the interstate transport of SO_2 and NO_x oxide emissions primarily from power plants. CAIR replaced the NO_x SIP Call for electric-generating units (EGUs). On October 4, 2007 the U.S. EPA published approval of a revision (*Appendix B*, 72 FR 56623) to Kentucky's SIP addressing CAIR requirements and a determination that the SIP fully implements the CAIR requirements for Kentucky.

The U.S. Court of Appeals for the D.C. Circuit has ruled on petitions for review of the CAIR and CAIR Federal Implementation Plans (FIPs), including their provisions establishing the CAIR NO_X annual and ozone season and SO_2 trading programs. On July 11, 2008, the Court issued an opinion (*North Carolina v. the U.S. EPA,* 531 F.3d 896, 901, D.C. Circuit 2008) vacating and remanding these rules; however, parties to the litigation requested rehearing of aspects of the Court's decision, including the vacatur of the rules. On December 23, 2008, the Court granted rehearing only to the extent that it remanded the rules to the U.S. EPA without vacating them (*North Carolina v. the U.S. EPA,* 531 F.3d 896, 905, D.C. Circuit 2008).

The December 23, 2008 court ruling left CAIR and the CAIR FIPs, including the CAIR trading programs, in place until the U.S. EPA issued a new rule to replace CAIR in accordance with the July 11, 2008 decision.

Upon the U.S. EPA designating in 2005, the Cincinnati-Hamilton area nonattainment for the 15 ug/m^3 annual standard, Kentucky was required to develop a plan to reduce NO_x, SO_x, and direct $PM_{2.5}$ emissions and to demonstrate that the area will meet the federal annual air quality standard by April 5, 2010. Kentucky's main $PM_{2.5}$ components are primary particles, SO_2, and NO_x,

which were included in the attainment demonstration analysis. As mentioned previously, VOCs and NH_3 were not included in the analysis since they were not part of Kentucky's current attainment strategy for $PM_{2.5}$. Kentucky emphasizes again that significant VOC reductions resulted from the VOCs controls that have been implemented for ozone attainment (*Appendix B*, 75 FR 47218, published August 5, 2010).

This is consistent with the U.S. EPA's "Clean Air Particle Implementation Rule" (*Appendix B*, 72 FR 20586, published April 25, 2007). In this rule, the U.S. EPA presumes NH_3 emissions are not a $PM_{2.5}$ attainment plan precursor and that States are not required to address VOC unless the State or the U.S. EPA makes technical demonstration that emissions of VOCs significantly contribute to nonattainment.

As noted previously, Kentucky developed regulations 401 KAR 51:210, 401 KAR 51:220, and 401 KAR 51:230 (effective February 2, 2007) in response to CAIR; those regulations are still in place. However, reductions due to this regulation and CAIR were not included in the inventory and its projections for the Kentucky portion of the nonattainment area.

On July 6th, 2010, the U.S. EPA issued the proposed Reduce Interstate Transport of Fine Particulate Matter and Ozone Rule (Transport Rule) to replace CAIR (*Appendix* B, 75 FR 45210). Specifically, this proposal would require significant reductions in SO_2 and NO_X that cross state lines. Emission reductions will begin to take effect in 2012, within one year after the rule is finalized. By 2014, the rule and other state and U.S. EPA actions would reduce SO_2 power plant emissions by 71% and NO_x emissions by 52% over 2005 levels.

Link to Transport Rule: **http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1**

Nonattainment problems are primarily a combination of local emissions and transported emissions from upwind sites. The structure of the CAA requires the U.S. EPA to develop national rules for certain types of sources which are significant contributors to local air quality problems, including motor vehicles and fuels. The CAA also provides for States to address emission sources on an area-specific basis through requirements as Reasonably Available Control Technology (RACT), Reasonably Available Control Measures (RACM), and Reasonable Further Progress (RFP). These national and state measures are included in a later discussion regarding emission controls applied.

Section 107(d)(3)(E) of the CAA allows states to request nonattainment areas to be redesignated to attainment provided certain criteria are met. The following are the criteria that must be met in order for an area to be redesignated from nonattainment to attainment:

- A determination that the area has attained the $PM_{2.5}$ standard.
- An approved SIP for the area under Section 110(k) of the CAA.
- A determination that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the SIP and other federal requirements.
- A fully approved maintenance plan under Section 175(A) of the CAA.
- A determination that all Section 110 and Part D requirements have been met.

This document addresses each of these requirements to support Kentucky's request that the Kentucky portions of the Cincinnati-Hamilton area be redesignated from nonattainment to attainment for the annual $PM_{2.5}$ standard, and provides additional information to support continued compliance with the annual $PM_{2.5}$ standard. In addition, the States of Ohio and Indiana also intend to submit requests for their respective portions of the nonattainment area.

Complete $PM_{2.5}$ quality-assured and certified ambient air quality monitoring data for the most recent 3 years (2007-2009) demonstrates that the air quality has met the NAAQS for annual $PM_{2.5}$ in this nonattainment area. The NAAQS design value (Table 2), accompanied by decreases in emission levels shown in this document (Table 49), supports a redesignation to attainment for the Cincinnati-Hamilton area based on the requirements in Section 107(d)(3)(E) of the CAA.

IMPROVEMENT IN AIR QUALITY

The $PM_{2.5}$ annual nonattainment designation was based on air quality data collected from 2001 through 2003 that exceeded the specified NAAQS level of 15 ug/m^3. Because the designation process occurred so close to the end of 2004, complete, certified 2004 ambient monitoring data quality-assured and submitted by February 22, 2005, was considered as well (*Appendix B,* 72 FR 20586). Designations became effective April 5, 2005.

The $PM_{2.5}$ annual data for the nonattainment area indicated no further exceedances of the annual $PM_{2.5}$ NAAQS standard and resulted in a decline in the design value for the most recent 3-year period (2007-2009). The AQS ambient data report is included in *Appendix C*.

Table 1 is a summary of the annual mean concentrations for the annual $PM_{2.5}$ NAAQS for the counties in the nonattainment area and the 3-year averages (*Data Source: the U.S. EPA Air Quality System*). A map indicating the location of the Kentucky and Ohio $PM_{2.5}$ monitors in the Cincinnati-Hamilton nonattainment area is included in *Appendix C*. Boone County, Kentucky and Dearborn County, Indiana do not have a $PM_{2.5}$ monitoring station in the nonattainment area. The annual mean values in Table 1 demonstrate an overall downward trend across the entire nonattainment area.

TABLE 1
Cincinnati-Hamilton, OH-KY-IN Annual $PM_{2.5}$ Nonattainment Area
SUMMARY OF ANNUAL MEAN PM2.5 CONCENTRATIONS
ANNUAL ARITHMETIC MEAN IN MICROGRAMS PER CUBIC METER

Site ID	County	2006	2007	2008	2009
21-037-3002	Campbell, KY	n/a	14.36	11.83	11.34
21-117-0007	Kenton, KY	13.29	14.20	11.99	11.04
39-017-0003	Butler, OH	14.05	15.41	13.69	12.68
39-017-0016	Butler, OH	13.99	14.94	13.75	13.08
39-025-0022	Clermont, OH	12.72	14.01	11.75	11.01
39-061-0006	Hamilton, OH	13.29	14.63	12.48	12.11
39-061-0014	Hamilton, OH	15.51	16.59	15.12	13.40
39-061-0040	Hamilton, OH	13.57	15.09	12.62	12.73
39-061-0042	Hamilton, OH	14.94	15.90	14.40	13.71
39-061-0043	Hamilton, OH	14.47	14.85	13.32	n/a
39-061-7001	Hamilton, OH	14.37	15.09	13.74	12.97
39-061-8001	Hamilton, OH	15.90	16.07	14.40	13.44
39-165-0007	Warren, OH	n/a	13.98	11.92	11.70

Data Source: U.S. EPA AQS n/a - No data collected.

Table 2 is a summary of the design value 3-year average for the annual $PM_{2.5}$ NAAQS calculated from the annual mean values in Table 1. The design values in Table 2 also demonstrate a downward trend across the entire nonattainment area.

TABLE 2
Cincinnati-Hamilton, OH-KY-IN Annual $PM_{2.5}$ Nonattainment Area
SUMMARY OF 3-YEAR AVERAGE PM2.5 CONCENTRATIONS
MICROGRAMS PER CUBIC METER

Site ID	County	Design Value 2008	Design Value 2009
21-037-3002	Campbell, KY	n/a	12.51
21-117-0007	Kenton, KY	13.16	12.41
39-017-0003	Butler, OH	14.38	13.93
39-017-0016	Butler, OH	14.23	13.92
39-025-0022	Clermont, OH	12.83	12.26
39-061-0006	Hamilton, OH	13.47	13.07
39-061-0014	Hamilton, OH	15.74	15.04
39-061-0040	Hamilton, OH	13.76	13.48
39-061-0042	Hamilton, OH	15.08	14.67
39-061-0043	Hamilton, OH	14.21	n/a
39-061-7001	Hamilton, OH	14.40	13.93
39-061-8001	Hamilton, OH	15.46	14.64
39-165-0007	Warren, OH	n/a	12.53

Data Source: U.S. EPA AQS n/a – No data collected.

According to guidance provided in the U.S. EPA's "Guideline on Data Handling Conventions for the PM NAAQS," the U.S. EPA-454/R-99-008, April 1999, an area is in compliance with the annual $PM_{2.5}$ NAAQS only if every monitoring site in the area meets the NAAQS. An individual site's 3-year average of the annual average concentrations is also called the site's design value.

In Table 2, the current 3-year average (2007-2009) for each individual site shows the site design value in attainment, as each monitor has achieved a calculated NAAQS monitor value below the 15.0 ug/m^3. The air quality design value for the area is the highest design value among all sites in the area. The area design values calculated for Cincinnati-Hamilton demonstrate that the annual $PM_{2.5}$ NAAQS has been attained. The area's design values have trended downward as

emissions have declined due to factors such as cleaner engine designs and fuels, and controls for EGUs. Emissions reductions are discussed in the section to follow.

The data collected by Kentucky was quality assured in accordance with 40 CFR 58 and was recorded in the U.S. EPA AQS and is therefore available to the public. The monitoring network will continue to remain operational in accordance to 40 CFR 58, with no monitoring reductions. The Air Quality System (AQS) ambient data report for $PM_{2.5}$ is included in *Appendix C.*

PERMANENT AND ENFORCEABLE EMISSION REDUCTIONS

The improvement in air quality in the Cincinnati-Hamilton area, as verified by the downward trend of fine particulate concentrations to a level attaining the annual NAAQS, is due to the implementation of permanent and enforceable emission reductions.

General meteorological information regarding temperatures and rainfall for years 2007 through 2009 are included in *Appendix C.*

On an annual basis, the monthly data indicates that 2007 overall in northern Kentucky was much warmer than normal, with numerous days June through September exceeding 90°F, while 2008 and 2009 were both less warm than normal. Precipitation on a monthly basis in 2007 was much drier than normal, with drought levels in the summer that would persist into the following year. However rainfall picked up by March, 2008, and overall 2008 was above normal for precipitation, while 2009 was closer to normal monthly rainfall levels. This information is

summarized as provided by the University of Kentucky Agricultural Weather Center at Covington in *Appendix C*.

Attaining the fine particulate NAAQS generally requires simultaneous emission reductions on the local, regional, and national levels. Emission reductions (in tons per day, or tpd) described below are from various programs and initiatives. The following categories of sources have shown or are expected to show emission reductions in direct $PM_{2.5}$, SO_2, and NO_x emissions due to regulatory measures implemented, both by the U.S. EPA and Kentucky.

CONTROLS APPLIED

Several control measures already in place or being implemented over the next few years will reduce stationary point, highway mobile, and nonroad mobile sources emissions. The Federal and State control measures were included for all of the future years and are discussed in the sections below.

FEDERAL CONTROL MEASURES

TIER 2 VEHICLE STANDARDS

On February 10, 2000, the U.S. EPA finalized a federal rule (65 FR 6698) to significantly reduce emissions from cars and light trucks, including sport utility vehicles (SUVs). Under this rule, automakers are required to sell cleaner cars, and refineries are required to make cleaner, low-sulfur gasoline. The federal rules were phased in between 2004 and 2009. The U.S. EPA has estimated that NO_x emission reductions will be approximately 77% for passenger cars, 86% for smaller SUVs, light trucks, and minivans; and 65% to 95% percent reductions for larger SUVs,

vans, and heavier trucks. Emission reductions of VOC will be approximately 12% for passenger cars; 18% for smaller SUVs, light trucks, and minivans; and 15% for larger SUVs, vans, and heavier trucks. The Tier 2 rule also reduced the sulfur content of gasoline to 30 parts per million (ppm) starting in January of 2006. Most gasoline sold in Kentucky prior to January 2006 had a sulfur content of approximately 300 ppm. Sulfur occurs naturally in gasoline, but interferes with the operation of catalytic converters on vehicles resulting in higher NOx emissions. Low-sulfur gasoline is necessary to achieve the Tier 2 vehicle emission standards.

HEAVY-DUTY GASOLINE AND DIESEL HIGHWAY VEHICLES STANDARDS

The U.S. EPA standards promulgated October 6, 2000, (65 FR 59896) to reduce NOx and VOC emissions from heavy-duty gasoline and diesel highway vehicles began to take effect in 2004. A second phase of standards and testing procedures, which began in 2007, began reducing particulate matter from heavy-duty highway engines, and reduces highway diesel fuel sulfur content to 15 ppm since the sulfur in fuel damages high efficiency catalytic exhaust emission control devices. The total program is expected to achieve a 90% reduction in particulate matter (PM) emissions and a 95% reduction in NOx emissions for these new engines using low-sulfur diesel, compared to existing engines using higher-content sulfur diesel.

LARGE NONROAD DIESEL ENGINES RULE

On May 11, 2004, the U.S. EPA promulgated new rules (69 FR 26222) for large nonroad diesel engines, such as those used in construction, agricultural, and industrial equipment, to be phased in between 2008 and 2014. The nonroad diesel rules also reduce the allowable sulfur in nonroad diesel fuel by over 99% by 2010. The U.S. EPA estimates that affected nonroad diesel engines

currently account for about 44% of total diesel PM emissions and about 12% of total NOx from mobile sources nationwide. These proportions can be even higher in some urban areas. Nonroad diesel fuel currently averages about 3,400 ppm sulfur. The rule has limited nonroad diesel sulfur content to 500 ppm in 2006 and 15 ppm in 2010. The combined engine and fuel rules would reduce NOx and PM emissions from large nonroad diesel engines by over 90%, compared to current nonroad engines using higher-content sulfur diesel.

NONROAD SPARK-IGNITION ENGINES AND RECREATIONAL ENGINES STANDARD

On November 8, 2002, the U.S. EPA promulgated rules (67 FR 68242) that regulate NOx, hydrocarbons (HC) and carbon monoxide (CO) for groups of previously unregulated nonroad engines. The standard applies to all new engines sold in the United States and imported after these standards began and applies to large spark-ignition engines (forklifts and airport ground service equipment), recreational vehicles (off-highway motorcycles and all-terrain-vehicles), and recreational marine diesel engines. The regulation varies based upon the type of engine or vehicle.

The large spark-ignition engines contribute to ozone formation and ambient CO and PM levels in urban areas. Tier 1 of this standard was implemented in 2004 while Tier 2 began in 2007. Like the large spark-ignition, recreational vehicles contribute to PM levels, as well ozone formation and ambient CO. For the off-highway motorcycles and all-terrain-vehicles, model year 2006, the new exhaust emissions standard was phased-in by 50% and for model years 2007 and later at 100%. Recreational marine diesel engines over 37 kilowatts are used in yachts, cruisers, and other types of pleasure craft. Recreational marine engines contribute to PM levels and ozone

formation, especially in marinas. Depending on the size of the engine, the standard began to be phased-in during 2006.

When all of the nonroad spark-ignition engines and recreational engines standards are fully implemented, an overall 72% reduction in HC, 80% reduction in NOx, and 56% reduction in CO emissions are expected by 2020. These controls will help reduce ambient concentrations of fine particulate matter, CO, and ozone.

NOx SIP Call in Surrounding States

On October 27, 1998, the U.S. EPA made a finding of significant contribution of NOx emissions from certain states and published a rule that set ozone season NOx budgets for the purpose of reducing regional transport of ozone (63 FR 57356). This rule, referred to as the NOx SIP Call, required ozone season controls to be put on utility and very large industrial boilers, as well as internal combustion engines in 22 states in the Eastern United States. This resulted in a NOx emissions budget for each state and the states were required to develop rules to meet their budget.

A trading program of NOx emissions was established, allowing sources to buy credits to meet their NOx budget as opposed to actually installing controls. The emission budgets were to be met by May of 2004. The amount of NOx emissions have decreased significantly in and around Kentucky. In fact, 2009 Kentucky emission inventory surveys indicate that NO_x emissions decreased by 2080 tons from the previous year.

STATE CONTROL MEASURES

Kentucky has adopted a number of regulations and legislation to address pollution issues across the State. These include the NOx SIP Call and the Open Burning Rules. These regulations are summarized below.

NOX SIP CALL RULE

In response to the U.S. EPA's NOx SIP call, Kentucky adopted rules to control the emissions of NOx from large stationary combustion sources. These rules cover fossil fuel-fired stationary boilers, combustion turbines, and combined cycle systems serving a generator with a nameplate capacity greater than 25 megawatts and selling any amount of electricity; fossil fuel-fired stationary boilers, combustion turbines, and combined cycle systems having a maximum design heat input greater than 250 million British thermal units per hour; and reciprocating stationary internal combustion engines rated at equal or greater than 2400 brake horsepower (3000 brake horsepower for diesel engines and 4400 brake horsepower for dual fuel engines). As part of the NOx SIP call, the U.S. EPA rules established a NOx budget for sources in Kentucky and other states.

Besides amending existing NOx rules and adopting new NOx rules specifically to address the U.S. EPA NOx SIP call, the Kentucky rules also require new sources to control emissions of NOx. The objective of this requirement is to aid in meeting the NOx budget for Kentucky for minor sources, and to aid in attaining and maintaining the ambient air quality standard for ozone in Kentucky. Kentucky's NOx SIP Call rule was predicted to reduce summertime NOx emissions from power plants and other industries statewide by 68% by 2006 (*Appendix G*).

KRS 224.10-100, *Powers and duties of the cabinet*, provides the Kentucky Energy and Environment Cabinet with the statutory authority to adopt and implement its NO_x SIP Call program. A link to KRS 224.10-100 is: **http://www.lrc.ky.gov/KRS/224-10/100.PDF**

REASONABLY AVAILABLE CONTROL MEASURES (RACM) - 401 KAR 50:012

The Kentucky $PM_{2.5}$ nonattainment areas will continue to implement the RACM measures already adopted. The analysis in the previously submitted "Kentucky Fine Particulate Matter ($PM_{2.5}$) Attainment Demonstration for the Louisville, KY-IN, Cincinnati-Middletown, OH-KY-IN, and Huntington-Ashland, WV-KY-OH $PM_{2.5}$ Nonattainment Areas" (December 2008) established that these measures contributed to the region being able to comply with the $PM_{2.5}$ NAAQS (1997).

A link to 401 KAR 50:012, *General application*, can be found at **http://www.lrc.state.ky.us/KAR/401/050/012.htm** and included in *Appendix G.*

OPEN BURNING BANS – 401 KAR 63:005

In 2005, Kentucky revised the open burning regulation to prohibit most types of open burning in moderate ozone nonattainment areas within Kentucky during the period of May-September when ozone is most likely to form. A copy of 401 KAR 63:005, *Open burning*, is located at **http://www.lrc.ky.gov/kar/401/063/005.htm.** This requirement continues in the Kentucky portions of the Cincinnati-Hamilton 8-hour ozone maintenance area counties of Boone, Campbell, and Kenton (*Appendix G*). The more stringent burning restrictions will increase

particle reductions across the Kentucky portion of the $PM_{2.5}$ nonattainment area during May-September.

FUGITIVE EMISSIONS – 401 KAR 63:010

For Kentucky, 401 KAR 63:010, *Fugitive emissions*, provides for the control of fugitive emissions in the state and can be found at **http://www.lrc.ky.gov/kar/401/063/010.htm**

CLEAN AIR INTERSTATE RULE (CAIR) – 401 KAR 51:210-230

On March 10, 2004, the U.S. EPA promulgated the CAIR. In response to the CAIR, Kentucky developed regulations 401 KAR 51:210, *CAIR NO_X annual trading program*; 401 KAR 51:220, *CAIR NO_x ozone season trading program*; and 401 KAR 51:230, *CAIR SO_2 trading program;* which became effective February 2, 2007.

Under the rules, Kentucky has caps as follows:

- Annual NOx: 83,205 tons for 2009-2014 and
  69,337 tons for 2015 and each year thereafter;
- Ozone season NOx: 36,109 tons for 2009-2014 and
  30,651 tons for 2015 and each year thereafter;
- Annual SO_2: 188,773 tons for 2010-2014 and
  132,141 tons for 2015 and each year thereafter.

The State's NOx allocations have been distributed based on allocation methodologies in regulations 401 KAR 51:210 (**http://www.lrc.state.ky.us/KAR/401/051/210.htm**) and 401

KAR 51:220 (**http://www.lrc.state.ky.us/KAR/401/051/220.htm**). The U.S. EPA will determine the SO_2 allocations, which are based on the acid rain program (**http://www.lrc.state.ky.us/KAR/401/051/230.htm**). This rule does not preclude Kentucky from adopting additional emission reduction requirements for covered sources if necessary to attain or maintain an ambient air quality standard (*Appendix G*).

The intent of the CAIR program was for national NO_x emissions to be cut from 4.5 million tons in 2004, to a cap of 1.5 million tons by 2009, and 1.3 million tons in 2018 in 28 eastern states. As a result of CAIR, the U.S. EPA projected that in 2009 Kentucky emissions of NO_x will decrease from a baseline of 176,00 tons per year without CAIR to 107,000 tons per year with CAIR. Projections also demonstrated that in 2010, emissions of SO_2 will decrease from a baseline of 447,000 tons per year without CAIR to 341,000 tons per year with CAIR. And by 2015, the U.S. EPA projects emissions of NO_x will decrease further to 77,000 tons per year while emissions of SO_2 will decrease to 270,000 tons per year within Kentucky. (Source: http://www.epa.gov/CAIR/ky.html)

As mentioned previously (page 8), Kentucky has not incorporated these expected CAIR reductions into the redesignation request inventories and projections. It should also be noted that Kentucky's SIP-approved NOx SIP Call program and regulations, and the CAIR program and regulations, are still in place and providing reductions.

All controls noted thus far for redesignation are expected to continue into the future. Those control measures will continue providing reduction for particulate precursors and emissions throughout the maintenance period.

In addition, various maximum available control technology (MACT) rules will be implemented throughout the maintenance period, providing additional particulate controls. These include:

MACT CONTROLS

- Industrial Boiler/Process Heater/RICE MACTs. The U.S. EPA issued final rules to substantially reduce emissions of toxic air pollutants from industrial, commercial and institutional boilers, process heaters and from stationary reciprocating internal combustion engines (RICE). These rules reduced emissions of a number of toxic air pollutants, including hydrogen chloride, manganese, lead, arsenic and mercury by 2009. This rule also reduces emissions of SO_2 and PM in conjunction with the toxic air pollutant reductions. The applied MACT control efficiencies were 4% for SO_2 and 40% for PM_{10} and $PM_{2.5}$. The U.S. EPA's industrial boiler MACT rules were vacated on June 8, 2007. The VISTAS states decided to leave these controls in the modeling since it is believed that by 2018 the U.S. EPA will have re-promulgated a boiler MACT rule or states will have addressed the issue through state rulemaking.

- Combustion Turbine MACT. The projection inventories do not include the NO_x co-benefit effects of the MACT regulations for gas turbines or stationary reciprocating internal combustion engines.

- VOC 2-, 4-, 7-, and 10-year MACT Standards. Various point source MACTs and associated emission reductions as implemented and to be implemented. Reductions occurring before 2002 were assumed to be accounted for in the base year inventory.

Section 110 and Part D requirements [CAA Section 107(d)(3)(E)(v)]

For purposes of redesignation, a state must meet all requirements of Section 110 and Part D of the CAA that were applicable prior to submittal of the complete redesignation request. Subpart 1 of Part D consists of general requirements applicable to all areas which are designated nonattainment based on a violation of the NAAQS. Subpart 4 of Part D consists of more specific requirements applicable to particulate matter (specifically to address PM_{10}). However, for the purpose of implementing the 1997 $PM_{2.5}$ standard, the U.S. EPA's Implementation Rule stated Subpart 1, rather than Subpart 4, is appropriate for the purpose of implementing $PM_{2.5}$ (72 FR 20589).

SECTION 110(A) REQUIREMENTS

Section 110(a) of Title I of the CAA contains the general requirements for a SIP. Section 110(a)(2) provides that the implementation plan submitted by a state must have been adopted by the state after reasonable public notice and hearing, and that, among other things, it must include: enforceable emission limitations and other control measures, means or techniques necessary to meet the requirements of the CAA; provide for establishment and operation of appropriate devices, methods, systems and procedures necessary to monitor ambient air quality; provide for implementation of a source permit program to regulate the modification and construction of any stationary source within the areas covered by the plan; include provisions for the implementation

of Part C, prevention of significant deterioration (PSD) and Part D, NSR permit programs; include criteria for stationary source emission control measures, monitoring, and reporting; include provisions for air quality modeling; and provide for public and local agency participation in planning and emission control rule development. In Kentucky's September 8, 2009, infrastructure SIP submission (*Appendix G*), Kentucky verified that the State fulfills the requirements of Section 110(a)(2) of the Act.

Section 110(a)(2)(D) also requires State plans to prohibit emissions from within the State which contribute significantly to nonattainment or maintenance areas in any other State, or which interfere with programs under Part C to prevent significant deterioration of air quality or to achieve reasonable progress toward the national visibility goal for Federal class I areas (national parks and wilderness areas). In order to assist States in addressing their obligations regarding regionally transported pollution, the U.S. EPA finalized CAIR to reduce SO_2 and NO_x emissions from large EGUs. Kentucky has met the requirements of the federal CAIR to reduce NO_x and SO_2 emissions contributing to downwind states. On October 4, 2007, the U.S. EPA published approval of Kentucky's CAIR program, which can be found in Kentucky Administrative Regulations 401 KAR 51:210, KAR 51:220 and KAR 51:230, effective December 3, 2007 (*Appendix G*).

On July 6, 2010, the U.S. EPA proposed a replacement to the CAIR program with the Transport Rule in 75 FR 45210. Upon finalization, the Transport Rule will continue to provide the reductions, and likely even greater reductions, that will be necessary for maintenance of the annual $PM_{2.5}$ standard to occur.

EMISSION INVENTORY

The U.S. EPA's redesignation guidance requires the submittal of a comprehensive inventory of $PM_{2.5}$ precursor emissions which include primary particles (i.e. organic carbon, crustal matter, and elemental carbon), SO_2, and NO_x, representative of the year when the area achieves attainment of the annual $PM_{2.5}$ air quality standard. As mentioned previously (pages 3 and 8), VOC and NH_3 are not addressed. Kentucky also must demonstrate that the improvement in air quality between the year that violations occurred and the year that attainment was achieved is based on permanent and enforceable emission reductions. Other emission inventory related requirements include a projection of the emission inventory to a year at least 10 years following redesignation; a demonstration that the projected level of emissions is sufficient to maintain the annual $PM_{2.5}$ standard; and a commitment to provide future updates of the inventory to enable tracking of emission levels during the 10-year maintenance period.

The emissions inventory development and emissions projection discussion below, with the exception of the mobile (on-road) emissions inventory and projections, identifies procedures used. Specific emissions data are provided for all counties, including those in Ohio, Kentucky and Indiana. Kentucky, Ohio, and Indiana emissions data were also obtained though the LADCO emissions inventory and projections. In this document, references to LADCO include the Midwest Regional Planning Organization. All of these inventories and emissions projections were prepared using similar methodologies. Mobile emissions inventories and projections for all counties were prepared by the Ohio, Kentucky, Indiana Regional Council of Governments (OKI).

Kentucky's 2005 Base Year was developed per procedures described in "Development of 2005 Base Year Growth and Control Factors for Lake Michigan Air Directors Consortium (LADCO) – Final Report" and provided in *Appendix D*. Kentucky's base year inventory and projected interim years are shown in Tables 16-27. Ohio's and Indiana's base year inventory and projected interim years are shown in Tables 31-45.

Kentucky's point, area, and nonroad sources were developed by LADCO as described in "Emission Inventory Assistance: 2005 Base Year Biogenic and Other (non-LADCO) State Emissions" in *Appendix D*. However, biogenic emissions are not included in these inventory summaries.

The on-road mobile source sector was addressed with specific $PM_{2.5}$ and NO_x modeling by OKI Regional Council of Governments, described in "Mobile Source Emissions Inventory for Cincinnati $PM_{2.5}$ Nonattainment Area – August 2010" and included in *Appendix E*. The mobile inventory is shown for each Kentucky county in Tables 3 through 5, and summarized in Table 6. The Ohio counties are shown in Tables 7 through 11, and summarized in Table 12. The on-road emission estimation totals for the nonattainment area and summarized in Table 13.

EMISSION PROJECTION METHODOLOGY

The U.S. EPA's redesignation guidance requires the submittal of a comprehensive inventory of $PM_{2.5}$ precursor emissions which include primary particles (i.e. organic carbon, crustal matter, and elemental carbon), SO_2, and NOx, representative of the year when the area achieves attainment of the annual $PM_{2.5}$ air quality standard.

One of the planning elements listed in the Calcagni memorandum dated September 4, 1992, (*Appendix A*) required for attainment redesignation purposes is developing a projection inventory that indicates the area will remain in attainment and which includes emission projections for at least 10 years after the U.S. EPA's official redesignation approval. Kentucky's projection inventory through the year 2021, and the methodology for performing that inventory, is located in *Appendix D*.

The emissions inventory is broken down into four components: point, area, highway mobile, and non-highway mobile sources. Using 2008 as the attainment year, the subsequent years were chosen at appropriate intervals and project maintenance for at least a 10-year period pending approval of the revision of the SIP.

The base year of 2005, the attainment year of 2008 for Kentucky (point, area and nonroad sources), as well as 2015 and 2021, were projected by LADCO using their 2005 Base Year Inventory methodology as provided in *Appendix D.*

Mobile emissions for the base year of 2005, the attainment year of 2008, the interim year of 2015, and the maintenance year of 2021 for the highway mobile, were developed by OKI using the U.S. EPA's Motor Vehicle Emissions Simulator (MOVES). The technical support document is provided in *Appendix E*. The two separate motor vehicle emission budgets are listed in Tables 14 and 15.

ADDITIONAL INTERPOLATED INTERIM PROJECTION YEARS FOR KENTUCKY

For this demonstration the U.S. EPA Region IV has requested that Kentucky provide two additional inventory interim years of 2011 and 2018 for all sectors interpolated through calculations described here:

There is a two-step calculation process to estimate the emissions of the interpolated year. The first step is to calculate the emissions growth rate, using the following formula.

Interpolated Year Emissions growth factor = EXP(RATE(n,,-PY,FY))^ni
Where n = number of years between the Past Year and the Future Year
PY = Past Year
FY = Future Year
ni = number of years between the Past Year and the chosen interpolated year

The second step is to multiply the calculated emissions growth rate by the Past Year emissions.

Interpolated Emissions = Interpolated Year Emissions growth factor x Past Year emissions

To calculate the interpolated year of 2011 using the formulas above, the two-step methodology can be applied in the following manner. First,

2011 Emissions growth factor = EXP(RATE(7,,-2008 emissions,2015 emissions))^3
Now the second calculation can interpolate the 2011 emissions by using the following formula.

Interpolated 2011 Emissions = Interpolated Year Emissions growth factor x Past Year emissions

The same methodology was used to calculate the interpolated year of 2018.

2018 Emissions growth factor = EXP(RATE(7,,-2015 emissions,2021 emissions))^3

Interpolated 2018 Emissions = Interpolated Year Emissions growth factor x Past Year emissions

The 2008 attainment year shows attainment of the NAAQS and the decrease in emission levels discussed in the emissions inventory (2008-2011-2015-2018-2021), which supports a redesignation to attainment for the Kentucky portion of the Cincinnati-Hamilton area based on the requirements in Section 107(d)(3)(E) of the CAA.

The Kentucky counties' base year inventory, attainment, interim, and maintenance year inventory for all sectors are provided in Tables 16-27.

Safety margins for the Kentucky portion are provided in Tables 28-30.

The Ohio and Indiana counties and safety margins are provided in Tables 31- 45.

MAINTENANCE PLAN

Section 107(d)(3)(E) of the CAA mandates that for an area to be redesignated to attainment, the U.S. EPA must approve a maintenance plan that meets the requirements of Section 175A of the CAA. The maintenance plan must constitute a SIP revision and provide for maintenance of the air quality in an affected area for at least 10 years after redesignation. Kentucky has chosen to project emissions through the year 2021.

The maintenance plan includes an emissions inventory for the attainment year (2008), projected inventories through 2021, a commitment to maintain the existing monitoring system, and contingency measures as may be necessary should the area fail to continue to maintain the annual fine particulate NAAQS.

A maintenance demonstration requires comparison of the projected emissions inventory with the baseline inventory. If the projected emissions remain at or below the baseline emissions, there is a demonstration of maintenance. If, however, the projected emissions are above the baseline, then additional measures are required to ensure the projected emissions will remain at or below the baseline emissions.

Tables 3 through 6 detail the projection of emissions through 2021. Boone, Campbell and Kenton counties' projected 2021 total emissions for $PM_{2.5}$, NO_x, and SO_2 are below the 2008 total emissions, thus demonstrating continued maintenance of the annual fine particulate standard. Emissions for 2005 are provided to be consistent with Ohio and Indiana's submittal to indicate the change in emissions up to the attainment year.

Documentation showing how emissions were grown is included in *Appendix D,* including the Technical Support Documents "E2: TSD Version IV 042508" for with CAIR and "E3: TSD Supplement without CAIR modeling."

POINT SOURCES

For this inventory purpose, the source emissions are calculated from data collected annually from the sources. This information is stored in an existing Kentucky Emissions Inventory System database and that information has been uploaded into the U.S. EPA National Emissions Inventory (NEI) system.

Information regarding how growth was projected for point sources is provided in *Appendix H* which contains the LADCO documentation regarding the emission inventory development and related Technical Support Documents.

AREA SOURCES/NON-HIGHWAY MOBILE SOURCES

As previously noted, the emissions and projections for area and nonhighway mobile sources were provided by LADCO. A more thorough discussion and documentation of these emissions and projections is provided in *Appendix D.*

MOBILE SOURCES

To calculate emissions from mobile sources, the division obtained mobile source emission projections from OKI in Cincinnati, Ohio. This organization is the metropolitan planning organization for the Greater Cincinnati area. These data and documentation on how these projections were performed can be found in *Appendix E,* including input and output files for those projections.

On-Road Emission Estimations

In coordination with the Ohio Department of Transportation (ODOT), OKI utilizes a regional travel demand forecast model to simulate traffic in the area and to forecast traffic flows for given growth expectations. The model has been validated to observed traffic volumes for the model base year 2005. The model is primarily used as a long range planning tool to evaluate the transportation system including determination of locations where additional travel capacity may be needed and to determine the infrastructure requirements necessary to meet that need. It is also used as a tool for air quality purposes to estimate the total emissions of pollution caused by vehicles in the area. The travel demand forecasting model is used to predict traffic volumes vehicle miles traveled (VMT), travel speeds, and the U.S. EPA computer program called MOVES is used to calculate emissions per mile. The product of these is the total amount of pollution emitted by the on-road vehicles for the area.

OVERVIEW OF MOBILE MODELING

The U.S. EPA published a Federal Register notice of availability on March 2, 2010 (*Appendix B*), to approve MOVES. Upon publication of the Federal Register notice, MOVES became the U.S. EPA's approved motor vehicle emission factor model for estimating VOCs, NO_x, CO, PM_{10} and $PM_{2.5}$ and other pollutants and precursors from cars, trucks, motorcycles, and buses by state and local agencies. MOVES is a computer program designed by the U.S. EPA to estimate air pollution emissions from mobile sources. MOVES replaces the U.S. EPA's previous emissions model for on-road mobile sources, MOBILE6.2. MOVES can be used to estimate exhaust and evaporative emissions as well as brake and tire wear emissions from all types of on-road vehicles.

The CAA requires the U.S. EPA to regularly update its mobile source emission models. The U.S. EPA continuously collects data and measures vehicle emissions to make sure the Agency has the best possible understanding of mobile source emissions. This assessment, in turn, informs the development of the U.S. EPA's mobile source emission models. MOVES represents the Agency's most up-to-date assessment of on-road mobile source emissions. MOVES also incorporates several changes to the U.S. EPA's approach to mobile source emission modeling based upon recommendations made to the Agency by the National Academy of Sciences.

The U.S. EPA believes that MOVES should be used in ozone, CO, PM, and NO_x SIP development as expeditiously as possible. The CAA requires that SIP inventories and control measures be based on the most current information and applicable models that are available when a SIP is developed.

Regarding transportation conformity, the U.S. EPA and U.S. DOT intend to establish a two-year grace period before MOVES is required for new transportation conformity analyses.

The MOVES more detailed approach (when compared with the previous MOBILE model) to modeling allows the U.S. EPA to easily incorporate large amounts of in-use data from a wide variety of sources, such as data from vehicle inspection and maintenance (I/M) programs, remote sensing device (RSD) testing, certification testing, portable emission measurement systems (PEMS), etc. This approach also allows users to incorporate a variety of activity data to better estimate emission differences such as those resulting from changes to vehicle speed and acceleration patterns. MOVES has a graphical user interface which allows users to more easily

set up and run the model. MOVES database-centered design provides users much greater flexibility regarding output choices. Unlike earlier models which provided emission factors in grams-per-mile in fixed output formats, MOVES output can be expressed as total mass (in tons, pounds, kilograms, or grams) or as emission factors (grams-per-mile and in some cases grams-per-vehicle). Output can be easily aggregated or disaggregated to examine emissions in a range of scales, from national emissions impacts down to the emissions impacts of individual transportation projects. The database-centered design also allows the U.S. EPA to update emissions data incorporated in MOVES more easily and will allow users to incorporate a much wider array of activity data to improve estimation of local emissions. For example, the improvements in MOVES will allow project-level $PM_{2.5}$ emissions to be estimated.

OKI utilized the U.S. EPA's emissions model MOVES to develop emissions factors for SO_2, NO_x and $PM_{2.5}$. Further details on the use of MOVES are found on *Appendix E*. Transportation system performance was estimated using the OKI Travel Demand Model Version 7.6. The model uses demographic and land use data and capacity and free-flow speed characteristics for each roadway segment in the network to produce a "loaded" highway network with forecasted traffic volumes with revised speeds based on specified speed/capacity relationships.

Travel analysis zones are the basic geographic unit for estimating travel in the OKI model. The OKI region is subdivided into 1608 traffic analysis zones to permit detail as well as manageability. A variety of socioeconomic data items are used in the OKI transportation planning process. These data are used primarily to forecast future travel patterns by serving as

independent variables in OKI trip generation equations. The following categories of planning data are utilized:

- Population
- Households
- Household vehicles
- Employment
- Labor force participation
- Area type

The principal data requirements of the OKI travel demand forecasting model are population and employment, from these variables other characteristics including household, labor force, and personal vehicles may be derived (OKI 2030 Regional Transportation Plan 2008 Update provides a complete demographic overview of the region).

OKI utilizes both base year (2005) and future year data (2010, 2020 and 2030) in the planning process. Planning data are maintained at the Traffic Analysis Zone (TAZ) level, and originate in the 2000 Census of Population and Housing. Base year 2005 and future year data for each variable are developed through various methods.

OKI's Travel Demand Model has been validated to observed traffic volumes for the model base year 2005. The modeling network encompasses the entire $PM_{2.5}$ nonattainment area. The modeling network also includes Greene, Miami, and Montgomery counties in Ohio and the remainder of Dearborn County, Indiana. The differences between estimated VMTs and 2005 observed VMT is less than 1%. A highway screenline analysis compares the screenline observed and simulated traffic volume discrepancies with the ODOT standard of maximum desirable

deviation. The comparison shows that the model performs at a satisfactory level and all the errors were under the ODOT curve (OKI's 2007 report, "OKI/MVRPC Travel Demand Model Methodology/Validation Report"). For the calibration, OKI used over 3000 traffic counts collected through 2006 by the ODOT, the Kentucky Transportation Cabinet, many county and local governments, transportation engineering consultants, and OKI. These traffic counts cover nearly 50% of the links in the OKI portion of the modeling network. The methodology provides consistency with past emission inventory and conformity analysis work performed by OKI.

OKI incorporates a variety of sources of local data to both improve and confirm the accuracy of VMT, as well as other travel-related parameters. Free flow speeds used on the highway and transit networks are based on travel time studies performed locally. An OKI post-processing program uses the loaded highway network to generate VMT by hour, VMT by speed distribution, and VMT by facility type. These tables are then included as input into MOVES. The VMT by hour tables utilize hourly traffic distribution and directional split factors for different roadway types as developed by OKI. The main source of the data was the permanent traffic counting stations located throughout the OKI region for the years of 1998-2002. These data were supplemented with data collected at coverage count stations (locations with counts taken on only one-two days). The stations were classified by area type (urban and rural) and functional classification (freeway, arterial and collector). Speeds representing various "loaded" conditions (with traffic volumes) are estimated using techniques from the 1997 Highway Capacity Manual. This permits the estimation of speeds as conditions vary from hour to hour on the different facility types throughout the region. The post-processing program performs the appropriate summation by area and roadway type as well as regional totals. OKI has also

developed seasonal conversion factors to adjust traffic volumes to summer conditions. The factors were derived from local data collected at permanent traffic counting stations during 1994-1997 utilizing the average daily traffic monthly conversion factors for June, July, and August.

ON-ROAD MOBILE EMISSION ESTIMATIONS FOR THE KENTUCKY PORTION

Tables 3 through 6 contain the results of the emissions analysis for the appropriate years. All emissions estimations are expressed in tons per year.

Table 3 – Boone County, Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	205.210	251.850	151.35	114.05
NO_x (tpy)	5,126.88	5,067.94	2,788.45	1,772.72
SO_2 (tpy)	15.91	16.71	20.67	24.37
Annual VMT	1,273,226,967	1,350,001,539	1,628,041,282	1,800,571,684

Table 4 – Campbell County, Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	120.300	146.460	82.36	60.09
NO_x (tpy)	3,041.21	2,988.33	1,570.14	985.28
SO_2 (tpy)	9.30	9.69	11.21	12.77
Annual VMT	741,790,595	774,762,718	875,774,487	936,445,352

Table 5 – Kenton County, Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	212.290	29.890	137.40	101.24
NO_x (tpy)	5,328.44	5,057.93	2,637.63	1,677.96
SO_2 (tpy)	16.24	16.34	18.62	21.48
Annual VMT	1,274,091,641	1,300,575,248	1,427,569,972	1,549,817,325

Table 6 – Summary of Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	537.8	645.62	371.11	275.38
NO_x (tpy)	13,496.53	13,114.20	6,996.22	6,421.15
SO_2 (tpy)	41.45	42.74	50.50	72.15
Annual VMT	3,289,109,203.00	3,425,339,505.00	3,931,385,741.00	5,452,303,073.00

ON-ROAD MOBILE EMISSION ESTIMATIONS FOR THE OHIO AND INDIANA PORTION

Table 7 - Butler County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	413.970	377.640	301.16	215.76
NO_x (tpy)	10,910.37	9,803.70	6,064.61	3,757.91
SO_2 (tpy)	30.01	34.25	34.28	37.90
Annual VMT	2,469,168,490	2,598,061,793	2,792,190,918	2,966,040,396

Table 8 – Clermont County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	281.790	256.600	204.32	145.39
NO_x (tpy)	7,295.87	6,516.40	3,993.63	2,449.31
SO_2 (tpy)	20.51	23.32	23.34	25.66
Annual VMT	1,684,261,582	1,765,146,867	1,899,319,930	2,005,373,961

Table 9 – Hamilton County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	1,222.020	1,080.540	826.00	571.48
NO_x (tpy)	31,127.09	27,020.93	15,925.19	9,530.16
SO_2 (tpy)	88.85	98.30	94.43	100.82
Annual VMT	7,241,536,812	7,421,012,594	7,630,239,650	7,811,745,310

Table 10 – Warren County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	320.740	289.560	242.05	177.61
NO_x (tpy)	8,224.57	7,267.18	4,598.44	2,875.72
SO_2 (tpy)	23.54	26.57	27.77	31.58
Annual VMT	1,949,619,088	2,031,755,542	2,285,057,933	2,498,434,852

Table 11 – Dearborn County, Indiana Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	33.980	29.890	25.14	18.11
NO_x (tpy)	865.46	748.81	482.33	297.95
SO_2 (tpy)	2.45	2.69	2.87	3.19
Annual VMT	196,738,031	199,778,078	223,644,622	240,321,759

Table 12 – Summary of Ohio and Indiana Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	2,272.50	2,034.23	1,598.67	1,128.35
NO_x (tpy)	58,423.36	51,357.02	31,064.20	18,911.05
SO_2 (tpy)	165.36	185.13	182.69	199.15
Annual VMT	13,541,324,003	14,015,754,874	14,830,453,053	15,521,916,278

ON-ROAD MOBILE SOURCE EMISSION TOTALS FOR THE ENTIRE NONATTAINMENT AREA

Table 13 – Emissions Estimations Totals for On-Road Mobile Sources for the Cincinnati-Hamilton Area

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	2,810.30	2,679.85	1,969.78	1,403.73
NO_x (tpy)	71,919.89	64,471.22	38,060.42	25,332.20
SO_2 (tpy)	206.81	227.87	233.19	271.30
Annual VMT	16,830,433,206.00	17,441,094,379.00	18,761,838,794.00	20,974,219,351.00

Motor Vehicle Emissions Budgets

Table 14 and Table 15 contain the motor vehicle emissions budgets for the Cincinnati-Hamilton area. For planning purposes, budgets are established for the combined Ohio and Indiana portions and for the separate Kentucky portion.

Table 14 - Mobile Vehicle Emissions Budget for the Ohio and Indiana portion

	2015 Estimated Emissions	2015 Mobile Safety Margin Allocation*	2015 Total Mobile Budget	2021 Estimated Emissions	2021 Mobile Safety Margin Allocation*	2021 Total Mobile Budget
PM2.5 (tpy)	1598.67	79.93	1678.60	1128.35	112.84	1241.19
NOx (tpy)	31,064.20	4659.63	35,723.83	18,911.05	2836.65	21,747.71
Annual VMT	14,830,453,053	-	-	15,521,916,278	-	-

*The 5 to15 percent margin of safety was calculated by taking 5 to15 percent of the mobile source emission estimates

Table 15 - Mobile Vehicle Emissions Budget for the Kentucky portion

	2015 Estimated Emissions	2015 Mobile Safety Margin Allocation*	2015 Total Mobile Budget	2021 Estimated Emissions	2021 Mobile Safety Margin Allocation*	2021 Total Mobile Budget
PM2.5 (tpy)	371.11	18.56	389.67	275.38	27.54	302.92
NOx (tpy)	6,996.22	1049.43	8,045.65	6,421.15	963.17	7,384.32
Annual VMT	3,931,385,741	-	-	5,452,303,073	-	-

*The 5 to15 percent margin of safety was calculated by taking 5 to15 percent of the mobile source emission estimates

The above budgets for the Ohio and Indiana portion and for the Kentucky portion of the area, agreed upon as part of the interagency consultation process, include the emission estimates calculated for 2015 and 2021 (from Table 6 and Table 12) with an additional 5% margin of safety allocated for $PM_{2.5}$ in 2015, 10% margin of safety allocated to $PM_{2.5}$ in 2021 and 15% margin of safety allocated to NO_x in 2015 and 2021. "Safety margin" means the amount by which the total projected emissions from all sources of a given pollutant are less than the total emissions that would satisfy the applicable requirement for reasonable further progress, attainment, or maintenance.

In an effort to accommodate future variations in travel demand models and VMT forecast when no change to the network is planned, the states consulted with the U.S. EPA to determine a reasonable approach to address this variation. Based on this discussion, a 5 to15 percent margin of safety allocation was agreed upon and has been added to the mobile emissions estimates for the nonattainment area.

All methodologies, the latest planning assumptions, and the safety margins allocations were determined through the interagency consultation process described in the Transportation Conformity Memorandum of Understanding (MOU) among OKI, ODOT, and Ohio EPA.

A 5 to 15 percent margin of safety is appropriate because: 1) there is an acknowledged potential variation in VMT forecast and potential estimated mobile source emissions due to expected modifications to TDM and mobile emissions models; and 2) the total decrease in emissions from all sources is sufficient to accommodate this 5 to 15 percent allocation of safety margin (as defined in 40 C.F.R. 93.101) to mobile sources while still continuing to maintain the total emissions in the Cincinnati-Hamilton area well below the 2008 attainment level of emissions.

The 5 to 15 percent margin of safety was calculated by taking 5 to 15 percent of the mobile source emission estimates. Safety margin, as defined by the conformity rule, looks at the total emissions from all sources in the nonattainment area. The actual allocation is less than 5 to 15 percent of the total emission reduction from all sources as can be seen from Table 49.

In summary, for all three states combined, the mobile budget safety margin allocation translates into an additional 98.49 tpy for $PM_{2.5}$ and 5,709.06 tpy for NO_x for 2015 and an additional 140.38 tpy for $PM_{2.5}$ and 3,799.82 tpy for NO_x for 2021.

When compared to the overall safety margin, as defined in 40 C.F.R. 93.101, it is evident this allocation is significantly below the total safety margin for this area.

The current $PM_{2.5}$ and NO_x mobile budgets for the fine particle NAAQS will no longer be applicable either after the effective date of the approved redesignation or after the effective date of any U.S. EPA action approving a finding that the $PM_{2.5}$ and NO_x conformity budgets included in this submittal are adequate for transportation conformity purposes, whichever date comes first.

Finally, it is important to underline that all motor vehicle emission budgets in this redesignation submittal, which are based on MOVES, will replace previous motor vehicle emission budgets on attainment demonstration submittals based on MOBILE6.2.

DEMONSTRATION AND PROJECTED EMISSIONS WITH SAFETY MARGINS

KENTUCKY PORTION OF THE NONATTAINMENT AREA

The 2005 and 2008 actual $PM_{2.5}$ emissions data below generally contains particulate fraction emissions only and not the condensible fractions as Ohio EPA did not have a consistent reporting requirement at those years. The U.S. EPA IPM modeling was used to generate future year EGU emissions with the CAIR program. The IPM modeling added additional $PM_{2.5}$ condensible emissions into future years. Therefore, comparing base and attainment year emissions with the

future year predictions is not accurate in the IPM CAIR modeling. This step leads to a false perception of significant $PM_{2.5}$ emissions growth. Modeling performed by LADCO, without CAIR, did not incorporate added condensible fraction emissions. Although Ohio EPA has stated that it is most appropriate to evaluate future year emissions that include the CAIR program, because of this flaw it will be more accurate and appropriate for the purposes of $PM_{2.5}$ to evaluate future year emissions without the CAIR program.

TABLE 16
BOONE COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED $PM_{2.5}$ EMISSIONS
(TONS PER YEAR)
2005-2021

$PM_{2.5}$	Boone					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	135.62	145.51	153.66	165.05	173.56	182.36
Area	351.27	353.71	356.21	359.57	362.07	364.58
Non-hwy total	304.76	310.52	291.92	268.43	252.14	236.53
Mobile	205.21	251.85	204.04	151.35	131.82	114.05
Total	**996.86**	**1061.59**	**1005.83**	**944.40**	**919.59**	**897.52**

TABLE 17
BOONE COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED NO_X EMISSIONS
(TONS PER YEAR)
2005-2021

NO_x	Boone					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	3984.30	2024.25	1819.34	1570.87	1472.97	1379.24
Area	1844.50	1897.28	1934.62	1985.25	2024.02	2063.30
Non-hwy total	3858.96	3772.42	3373.85	2892.72	2524.78	2189.66
Mobile	5126.88	5067.94	3965.01	2788.45	2241.93	1772.72
Total	**14814.64**	**12761.89**	**11092.81**	**9237.29**	**8263.71**	**7404.92**

TABLE 18
BOONE ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED SO_2 EMISSIONS
(TONS PER YEAR)
2005-2021

SO_2	Boone					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	3661.80	2830.13	2746.25	2637.34	2596.24	2555.57
Area	1054.33	1066.79	1078.16	1093.47	1104.96	1116.53
Non-hwy total	494.27	435.93	387.02	328.37	287.59	250.36
Mobile	15.91	16.71	18.33	20.67	22.47	24.37
Total	**5226.31**	**4349.56**	**4229.77**	**4079.85**	**4011.26**	**3946.83**

TABLE 19
CAMPBELL COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED $PM_{2.5}$ EMISSIONS
(TONS PER YEAR)
2005-2021

$PM_{2.5}$	Campbell					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	84.26	89.52	94.65	101.84	107.03	112.39
Area	200.08	201.26	200.74	200.05	199.68	199.32
Non-hwy total	80.95	76.09	67.61	57.43	49.30	41.99
Mobile	120.30	146.46	115.57	82.36	70.64	60.09
Total	**485.59**	**513.33**	**478.58**	**441.68**	**426.65**	**413.79**

TABLE 20
CAMPBELL COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED NO_X EMISSIONS
(TONS PER YEAR)
2005-2021

NOx	Campbell					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	53.68	49.52	51.33	53.81	54.51	55.21
Area	523.45	536.71	548.21	563.83	575.52	587.37
Non-hwy total	1902.55	1833.46	1610.33	1345.37	1137.03	951.58
Mobile	3041.21	2988.33	2296.09	1570.14	1254.81	985.28
Total	**5520.89**	**5408.02**	**4505.95**	**3533.15**	**3021.87**	**2579.44**

TABLE 21
CAMPBELL COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED SO_2 EMISSIONS
(TONS PER YEAR)
2005-2021

SOx	Campbell					
Sector	2005 Base	2008 Attain	2011 Interim	2015 Interim	2018 Interim	2021 Maintain
Point	0.97	0.96	0.99	1.04	1.06	1.09
Area	471.77	479.14	484.48	491.66	497.18	502.75
Non-hwy total	239.99	206.21	180.11	149.28	125.14	103.78
Mobile	9.30	9.69	10.32	11.21	11.97	12.77
Total	**722.03**	**696.00**	**675.90**	**653.19**	**635.36**	**620.39**

TABLE 22
KENTON COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED $PM_{2.5}$ EMISSIONS
(TONS PER YEAR)
2005-2021

$PM_{2.5}$	Kenton					
Sector	2005 Base	2008 Attain	2011 Interim	2015 Interim	2018 Interim	2021 Maintain
Point	9.53	11.11	12.09	13.50	14.60	15.76
Area	365.74	366.69	365.44	363.77	362.71	361.65
Non-hwy total	119.08	110.61	98.06	83.03	70.88	59.98
Mobile	212.29	247.31	194.23	137.40	118.39	101.24
Total	**706.64**	**735.72**	**669.82**	**597.70**	**566.58**	**538.63**

TABLE 23
KENTON COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED NO_X EMISSIONS
(TONS PER YEAR)
2005-2021

NOx	Kenton					
Sector	2005 Base	2008 Attain	2011 Interim	2015 Interim	2018 Interim	2021 Maintain
Point	19.50	20.44	21.01	21.79	22.43	23.09
Area	1542.27	1581.60	1612.65	1654.75	1686.60	1718.86
Non-hwy total	2684.68	2562.60	2235.19	1848.86	1540.79	1269.32
Mobile	5328.44	5057.93	3874.85	2637.63	2121.33	1677.96
Total	**9574.89**	**9222.57**	**7743.70**	**6163.03**	**5371.16**	**4689.23**

TABLE 24
KENTON COUNTY ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
PROJECTED SO_2 EMISSIONS
(TONS PER YEAR)
2005-2021

SOx	Kenton					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	12.91	13.89	14.42	15.16	15.78	16.41
Area	1196.61	1210.42	1222.57	1238.92	1251.23	1263.63
Non-hwy total	248.34	190.40	160.90	127.09	101.12	78.99
Mobile	16.24	16.34	17.29	18.62	20.02	21.48
Total	**1474.10**	**1431.05**	**1415.19**	**1399.79**	**1388.15**	**1380.51**

TABLE 25
ANNUAL $PM_{2.5}$ FOR KY PORTION OF THE NONATTAINMENT AREA
PROJECTED $PM_{2.5}$ EMISSIONS
(TONS PER YEAR)
2005-2021

$PM_{2.5}$	Boone, Campbell, Kenton					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	229.41	246.14	260.41	280.39	295.19	310.51
Area	917.09	921.66	922.39	923.39	924.46	925.55
Non-hwy total	504.79	497.22	457.58	408.89	372.32	338.50
Mobile	537.80	645.62	513.85	371.11	320.84	275.38
Total	**2189.09**	**2310.64**	**2154.23**	**1983.78**	**1912.82**	**1849.94**

TABLE 26
ANNUAL $PM_{2.5}$ FOR KY PORTION OF THE NONATTAINMENT AREA
PROJECTED NO_X EMISSIONS
(TONS PER YEAR)
2005-2021

NO_X	Boone, Campbell, Kenton					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	4057.48	2094.21	1891.67	1646.47	1549.91	1457.54
Area	3910.22	4015.59	4095.47	4203.83	4286.15	4369.53
Non-hwy total	8446.19	8168.48	7219.36	6086.95	5202.60	4410.56
Mobile	13496.53	13114.20	10135.95	6996.22	5618.08	4435.96
Total	**29910.42**	**27392.48**	**23342.46**	**18933.47**	**16656.74**	**14673.59**

TABLE 27
ANNUAL $PM_{2.5}$ FOR KY PORTION OF THE NONATTAINMENT AREA
PROJECTED SO_2 EMISSIONS
(TONS PER YEAR)
2005-2021

SO_2	Boone, Campbell, Kenton					
Sector	**2005 Base**	**2008 Attain**	**2011 Interim**	**2015 Interim**	**2018 Interim**	**2021 Maintain**
Point	3675.68	2844.98	2761.67	2653.54	2613.08	2573.07
Area	2722.71	2756.35	2785.21	2824.05	2853.38	2882.91
Non-hwy total	982.60	832.54	728.03	604.74	513.85	433.13
Mobile	41.45	42.74	45.94	50.50	54.46	58.62
Total	**7422.44**	**6476.61**	**6320.86**	**6132.83**	**6034.77**	**5947.73**

TABLE 28
KY PORTION OF THE ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
$PM_{2.5}$ SAFETY MARGINS

(TONS PER YEAR) $PM_{2.5}$	Boone	Campbell	Kenton
Sector			
EGU Point	-6.72	0.00	0.00
Non-EGU	-30.13	-22.87	-4.65
Non-road	37.60	11.51	23.76
Other	-10.87	1.94	5.04
MAR	36.39	22.59	26.87
On-road	137.80	86.37	146.07
Total	**164.07**	**99.54**	**197.09**

TABLE 29
KY PORTION OF THE ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
NO_x SAFETY MARGINS

(TONS PER YEAR) NO_x	Boone	Campbell	Kenton
Sector			
EGU Point	654.56	0.00	0.00
Non-EGU	-9.55	-5.69	-2.64
Non-road	484.31	132.92	308.27
Other	-166.02	-50.66	-137.26
MAR	1098.45	748.96	985.01
On-road	3295.22	2003.05	3379.97
Total	**5356.97**	**2828.59**	**4533.35**

TABLE 30
KY PORTION OF THE ANNUAL $PM_{2.5}$ NONATTAINMENT AREA
SO_2 SAFETY MARGINS

(TONS PER YEAR) SO_2	Boone	Campbell	Kenton
Sector			
EGU Point	277.60	0.00	0.00
Non-EGU	-3.04	-0.13	-2.52
Non-road	25.94	7.72	17.96
Other	-49.74	-23.61	-53.21
MAR	159.63	94.71	93.45
On-road	-7.66	-3.08	-5.14
Total	**402.73**	**75.61**	**50.54**

THE OHIO AND INDIANA PORTION OF THE NONATTAINMENT AREA

Ohio EPA has revised the Butler County, Ohio $PM_{2.5}$, NO_x and SO_2 Emissions Inventory (non-EGU) to incorporate the total emissions reduction credits available and used to offset the allowed emissions of a major source modified within the maintenance area that will begin operating during the maintenance period. The total emissions included in the inventory, and in all the Butler County tables below for this facility in 2015 and 2021, are 117.81 tpy $PM_{2.5}$, 479.57 tpy NOx and 1209.92 tpy SO_2. The emissions increase does not significantly impact the safety margin for this area or prevent the area from maintaining the standard in future years.

Particulate Matter ($PM_{2.5}$)

Table 31 - **Butler County**, Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	15.27	16.78	15.86	15.59	1.19
Non-EGU	944.29	1045.15	1254.70	1337.03	-291.88
Non-road	185.28	158.41	109.75	66.98	91.43
Other	173.24	180.43	180.86	182.45	-2.02
MAR	31.19	27.40	16.01	6.43	20.97
On-road	413.97	377.64	301.16	215.76	161.88
TOTAL	1763.24	1805.81	1878.34	1824.24	-18.43

Table 32 - **Clermont County**, Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	648.21	532.61	651.88	711.22	-178.61
Non-EGU	7.93	3.86	6.42	7.33	-3.47
Non-road	104.54	89.84	62.51	38.56	51.28
Other	193.70	196.15	193.49	191.83	4.32
MAR	6.11	5.64	3.54	1.81	3.83
On-road	281.79	256.60	204.32	145.39	111.21
TOTAL	1242.28	1084.70	1122.16	1096.14	-11.44

Table 33 - **Hamilton County**, Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	648.64	202.88	554.65	708.74	-505.86
Non-EGU	161.88	158.14	171.28	179.45	-21.31
Non-road	355.97	307.30	218.86	141.16	166.14
Other	303.61	323.94	330.03	338.37	-14.43
MAR	42.04	37.82	23.54	11.64	26.18
On-road	1222.02	1080.54	826.00	571.48	509.06
TOTAL	2734.16	2110.62	2124.36	1950.84	159.78

Table 34 - **Warren County**, Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	18.75	19.91	19.01	18.60	1.31
Non-road	143.72	122.20	79.69	42.68	79.52
Other	236.92	238.33	233.88	230.65	7.68
MAR	2.95	2.58	1.53	0.64	1.94
On-road	320.74	289.56	242.05	177.61	111.95
TOTAL	723.08	672.58	576.16	470.18	202.40

Table 35 - **Dearborn County**, Indiana $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	673.94	804.18	847.16	922.81	-118.63
Non-EGU	67.38	62.02	60.00	57.32	4.70
Non-road	23.96	19.91	13.34	9.07	10.84
Other					
MAR	4.29	4.29	4.11	3.98	0.31
On-road	33.98	29.89	25.14	18.11	11.78
TOTAL	803.55	920.29	949.75	1011.29	-91.00
*MAR emissions are included in Non-road emissions					

Oxides of Nitrogen (NO_x)

Table 36 - **Butler County**, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	743.27	856.92	343.95	124.10	732.82
Non-EGU	4367.15	3940.28	4626.45	4686.11	-745.83
Non-road	2348.42	1986.81	1228.83	572.69	1414.12
Other	796.34	807.64	811.94	817.28	-9.64
MAR	919.91	847.08	545.76	297.37	549.71
On-road	10910.37	9803.70	6064.61	3757.91	6045.79
TOTAL	20085.46	18242.43	13621.54	10255.46	7986.97

Table 37 - **Clermont County**, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	28063.56	24233.18	16491.26	10451.28	13781.90
Non-EGU	67.50	42.71	60.83	68.68	-25.97
Non-road	1218.23	1039.67	655.01	322.89	716.78
Other	612.97	619.27	620.94	623.36	-4.09
MAR	259.07	245.25	159.04	89.20	156.05
On-road	7295.87	6516.40	3993.63	2449.31	4067.09
TOTAL	37517.20	32696.48	21980.71	14004.72	18691.76

Table 38 - **Hamilton County**, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	15236.04	12372.00	7236.90	5036.15	7335.85
Non-EGU	2756.21	2652.79	2943.73	3139.37	-486.58
Non-road	4845.98	4029.63	2464.90	1098.14	2931.49
Other	1923.27	1955.47	1974.77	1995.51	-40.04
MAR	1463.80	1372.41	909.89	532.19	840.22
On-road	31127.09	27020.93	15925.19	9530.16	17490.77
TOTAL	57352.39	49403.23	31455.38	21331.52	28071.71

Table 39 - **Warren County**, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	1024.95	1043.27	1035.29	1034.26	9.01
Non-road	1789.97	1517.53	919.21	403.56	1113.97
Other	426.57	432.28	434.26	436.82	-4.54
MAR	96.07	89.92	60.22	35.92	54.00
On-road	8224.57	7267.18	4598.44	2875.72	4391.46
TOTAL	11562.13	10350.18	7047.42	4786.28	5563.90

Table 40 - **Dearborn County**, Indiana NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	7961.30	7429.20	9862.76	11229.31	-3800.11
Non-EGU	2024.68	1979.83	1965.19	1943.22	36.61
Non-road	382.53	318.09	219.83	154.18	163.91
Other	141.37	145.42	143.39	142.90	2.52
MAR*					
On-road	865.46	748.81	482.33	297.95	450.86
TOTAL	11375.34	10621.35	12673.50	13767.56	-3146.21
*MAR emissions are included in Non-road emissions					

Sulfur Dioxide (SO_2)

Table 41 - Butler County, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	1959.10	2181.63	654.49	0.00	2181.63
Non-EGU	6185.26	5442.54	6847.48	6828.13	-1385.59
Non-road	260.36	95.29	15.09	0.80	94.49
Other	224.54	221.09	209.01	198.96	22.13
MAR	80.84	79.05	62.61	49.44	29.61
On-road	30.01	34.25	34.28	37.90	-3.65
TOTAL	8740.11	8053.85	7822.96	7115.23	938.62

Table 42 - **Clermont County**, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	88876.65	42918.28	32590.92	20589.16	22329.12
Non-EGU	162.19	118.05	148.28	160.98	-42.93
Non-road	138.93	50.86	8.05	0.43	50.43
Other	164.72	162.20	151.29	142.32	19.88
MAR	22.73	15.39	5.26	0.78	14.61
On-road	20.51	23.32	23.34	25.66	-2.34
TOTAL	89385.73	43288.10	32927.14	20919.33	22368.77

Table 43 - **Hamilton County**, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	77381.13	24693.00	16390.65	7508.46	17184.54
Non-EGU	7819.40	6552.65	7739.34	8309.88	-1757.23
Non-road	474.85	174.16	28.47	1.93	172.23
Other	163.45	161.80	151.81	143.71	18.09
MAR	117.60	100.46	64.96	34.20	66.26
On-road	88.85	98.30	94.43	100.82	-2.52
TOTAL	86045.28	31780.37	24469.66	16099.00	15681.37

Table 44 - **Warren County**, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	3.39	3.53	3.45	3.42	0.11
Non-road	23.54	26.57	27.77	31.58	-5.01
Other	140.25	138.31	131.36	125.59	12.72
MAR	8.13	7.99	6.34	5.03	2.96
On-road	208.73	76.29	11.87	1.73	74.56
TOTAL	384.04	252.69	180.79	167.35	85.34

Table 45 - **Dearborn County**, Indiana SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	46533.70	25729.10	39295.70	36843.66	-11114.56
Non-EGU	1331.15	1334.33	1335.94	1337.95	-3.62
Non-road	40.16	17.38	4.73	1.14	16.24
Other	78.72	81.02	77.64	75.69	5.33
MAR*					
On-road	2.45	2.69	2.87	3.19	-0.50
TOTAL	47986.18	27164.52	40716.88	38261.63	-11097.11
*MAR emissions are included in Non-road emissions					

(CONTINUED NEXT PAGE)

TOTAL OF ALL EMISSIONS

It is important to recognize in Tables 46 through 48 the differences between the 2008 attainment year tpd for each pollutant and the projected 2021 maintenance tpd for each pollutant. Table 49 shows that for the combined nonattainment area, projected 2021 emissions for all pollutants are less than 2008 attainment year levels.

*****Summary Tables for Emission Inventory Totals*****

Table 46 – **Cincinnati-Hamilton Area $PM_{2.5}$ Emission Inventory** Totals for Base Year 2005, Estimated 2008, and projected 2015 and 2021 (tpy) – Without CAIR

$PM_{2.5}$	**2005 Base**	**2008 Attainment**	**2015 Interim**	**2021 Maintenance**	**Safety Margin**
Butler, OH	1763.24	1805.81	1878.34	1824.24	-18.43
Clermont, OH	1242.28	1084.70	1122.16	1096.14	-11.44
Hamilton, OH	2734.16	2110.62	2124.36	1950.84	159.78
Warren, OH	723.08	672.58	576.16	470.18	202.40
Dearborn, IN	803.55	920.29	949.75	1011.29	-91.00
Boone, KY	996.86	1061.59	944.40	897.52	164.07
Campbell, KY	485.59	513.33	441.68	413.79	99.54
Kenton, KY	706.64	735.72	597.70	538.63	197.09
COMBINED $PM_{2.5}$ TOTAL	**9455.40**	**8904.64**	**8634.55**	**8202.63**	**702.01**

Table 47 - **Cincinnati-Hamilton Area NO_x Emission Inventory** Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

NO_x	**2005 Base**	**2008 Attainment**	**2015 Interim**	**2021 Maintenance**	**Safety Margin**
Butler, OH	20085.46	18242.43	13621.54	10255.46	7986.97
Clermont, OH	37517.20	32696.48	21980.71	14004.72	18691.76
Hamilton, OH	57352.39	49403.23	31455.38	21331.52	28071.71
Warren, OH	11562.13	10350.18	7047.42	4786.28	5563.90
Dearborn, IN	11375.34	10621.35	12673.50	13767.56	-3146.21
Boone, KY	14814.64	12761.89	9237.29	7404.92	5356.97
Campbell, KY	5520.89	5408.02	3533.15	2579.44	2828.58
Kenton, KY	9574.89	9222.57	6163.03	4689.23	4533.34
COMBINED NOx TOTAL	**167802.94**	**148706.15**	**105712.02**	**78819.13**	**69887.02**

Table 48 - **Cincinnati-Hamilton Area SO_2 Emission Inventory** Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

SO_2	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
Butler, OH	8740.11	8053.85	7822.96	7115.23	938.62
Clermont, OH	89385.73	43288.10	32927.14	20919.33	22368.77
Hamilton, OH	86045.28	31780.37	24469.66	16099.00	15681.37
Warren, OH	384.04	252.69	180.79	167.35	85.34
Dearborn, IN	47986.18	27164.52	40716.88	38261.63	-11097.11
Boone, KY	5226.31	4349.56	4079.85	3946.83	402.73
Campbell, KY	722.03	690.00	653.19	620.39	75.61
Kenton, KY	1474.10	1431.05	1399.79	1380.51	50.54
COMBINED SO_2 TOTAL	**239963.78**	**117016.14**	**112250.26**	**88510.27**	**28505.87**

$PM_{2.5}$, NO_x, and SO_2 Projected Emission Decreases

Table 49 - **Cincinnati-Hamilton Area Comparison of 2008 attainment year and 2015 interim and 2021 projected emission estimates (**tpy)

	2008 Base	2015 Interim	2015 Projected Decrease	2021 Maintenance	2021 Projected Decrease
$PM_{2.5}$	8,904.64	8,634.55	270.09	8,202.63	702.01
NO_x	148,706.15	105,712.02	42,994.13	78,819.13	69,887.02
SO_2	117,016.14	112,250.26	4,765.88	88,510.27	28,505.87

As shown in the table above (Table 49), $PM_{2.5}$ emissions in the nonattainment area are projected to decrease by 270.09 tpy in 2015 and 702.01 tpy in 2021. NO_x emissions in the nonattainment area are projected to decrease by 42,994.13 tpy in 2015 and 69,887.02 tpy in 2021. SO_2 emissions in the nonattainment area are projected to decline by 4,765.88 tpy in 2015 and 28,505.87 in 2021.

Area source emissions and, to a lesser extent, point sources show an increase due to expectations that the population will grow in this area; however, cleaner vehicles and fuels are expected to be in place in 2009 and 2018, and the Transport Rule will be implemented in 2012 and 2014. These programs should cause an overall drop in all three pollutants emissions. Decreases from the U.S.

EPA rules covering Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (*FR* Feb 10, 2000 Vol. 65 No. 28), Highway Heavy-Duty Engine Rule (*FR* Oct. 21, 1997 Vol. 62 No. 203), and the Non-Road Diesel Engine Rule (*FR* Oct. 23, 1998 Vol. 63, No. 205) are factored into the changes.

PLAN TO MAINTAIN AIR QUALITY

The Commonwealth of Kentucky and the U.S. EPA have instituted previously mentioned control strategy programs that will remain enforceable and are hereby submitted as a plan to maintain air quality which meets the NAAQS for the annual $PM_{2.5}$ standard. Sources are prohibited from reducing emission controls following the redesignation of the area.

In addition to these measures, further reductions will be achieved through federal regulations such as the "FIP to Reduce Interstate Transport of Fine Particulate Matter and Ozone", published as a proposed rule on August 2, 2010. This rule is proposing to further regulate EGUs in 32 states to limit NO_x and SO_2 emissions.

EXISTING MONITORING NETWORK

In addition to the maintenance plan discussed above, the existing $PM_{2.5}$ monitoring network located within the Kentucky counties of the Cincinnati-Hamilton $PM_{2.5}$ Nonattainment area has been approved by the U.S. EPA. The monitoring network will continue to remain operational in accordance to 40 CFR 58, with no reductions.

CONTINGENCY MEASURES

Future reviews of actual emissions for this redesignated area will be performed using the latest emission factors, models, and methodologies. For these periodic inventories, Kentucky will review the assumptions made for the purpose of the maintenance demonstration concerning projected growth of activity levels. If any of these assumptions appear to have changed substantially, Kentucky will re-project emissions.

In the event that a measured value of the weighted annual mean is 15.5 micrograms per cubic meter or greater occurs in a single calendar year in any portion of the maintenance area, the state will evaluate existing control measures to see if any further emission reduction measures should be implemented at that time.

In the event of a monitored violation of the annual $PM_{2.5}$ NAAQS in the Cincinnati-Hamilton maintenance area, the Commonwealth commits to adopt, within nine months, one or more of the following contingency measures to re-attain the standard. All regulatory programs will be implemented within 18 months after the triggering monitored violation.

- Implementation of a program to require additional emission reductions on stationary sources;
- Implementation of fuel programs, including incentives for alternative fuels;
- Restriction of certain roads or lanes to, or construction of such roads or lanes for use by, passenger buses or high-occupancy vehicles;
- Trip-reduction ordinances;
- Employer-based transportation management plans, including incentives;
- Programs to limit or restrict vehicle use in downtown areas, or other areas of emission concentration, particularly during periods of peak use;
- Programs for new construction and major reconstructions of paths or tracks for use by pedestrians or by non-motorized vehicles when economically feasible and in the public interest;
- Diesel reduction emission strategies, including diesel retrofit programs

Kentucky also reserves the right to implement other contingency measures if new control programs should be developed and deemed more advantageous for the area.

Section 175A(b) of the CAA requires that eight years after formal redesignation, the state continues to provide for maintenance of the standard by submitting another maintenance plan that covers an additional 10 years. If this requirement remains applicable for this area, Kentucky commits to submit to the U.S. EPA a plan for future maintenance of the standard in Boone, Campbell and Kenton counties as required.

PUBLIC PARTICIPATION

Kentucky held a public hearing to receive comments on this proposed redesignation request on December 15, 2010 at the offices of the Northern Kentucky Area Development District. A copy of the public hearing notice and a copy of the advertisements are included in *Appendix I*.

A copy of the Energy and Environment Cabinet's response to comments received during that public review period is included as *Appendix I*.

Appendix A

U.S. EPA Memorandums

regarding

Redesignations

MEMORANDUM

SUBJECT: Processing of State Implementation Plan (SIP) Submittals

FROM: John Calcagni, Director
Air Quality Management Division, OAQPS (MD-15)

TO: Director, Air, Pesticides and Toxics Management Division, Regions I and IV
Director, Air and Waste Management Division, Region II
Director, Air, Radiation, and Toxics Division, Region III
Director, Air and Radiation Division, Region V
Director, Air, Pesticides, and Toxics Division, Region VI
Director, Air and Toxics Division, Regions VII, VIII, IX, and X

This memorandum provides guidance concerning the processing of SIP submittals. In general, there are three situations that can occur related to each required submittal: the State may fail to submit the required plan, the State may make a submittal that is not complete, or the State may make a complete submittal. Once a State submits a SIP and the Environmental Protection Agency (EPA) has determined that the submittal is complete, EPA must either approve or disapprove the submittal within a specified time period. However, if the State fails to make a required submittal or makes a submittal that is determined to be incomplete, the sanctions and Federal implementation plan (FIP) provisions of sections 179 and 110(c), respectively, will be triggered. In addition, disapproval of a submittal also triggers the sanctions and FIP provisions. These provisions are discussed in further detail in this memorandum.

There are, however, three alternatives to full approval or full disapproval of a complete SIP submittal: partial approval,

limited approval, and conditional approval. Each of these is discussed in more detail below along with some guidance as to when each might be used. In addition, Attachment 1 to this memorandum contains several examples of how these may be used. Attachment 2 to this memorandum is a table that summarizes the requirements discussed below.

Partial Approval/Disapproval

Section 110(k)(3) of the amended Clean Air Act (Act) addresses the situation in which an entire submittal, or a separable portion of a submittal, meets all applicable requirements of the Act. Where the entire submittal meets all the requirements of the Act, EPA will fully approve the entire submittal. In the case where a separable portion of the submittal meets all of the applicable requirements, partial approval may be used to approve that part of the submittal and disapprove the remainder. It is important that the two parts of the submittal be separable. By separable, EPA means that the action it anticipates taking will not result in the approved rule(s) being more stringent than the State anticipated. See Bethlehem Steel Corp. v. Gorsuch, 742 F. 2d 1028 (7th Cir. 1984); Indiana and Michigan Elec. Co. v. U.S. E.P.A., 733 F. 2d 489 (7th Cir. 1984). For example, EPA cannot approve part of a submittal that specifies control measures and disapprove the part that specifies the test methods associated with those control measures. The EPA has frequently taken a partial approval approach in the past to process groups of rules that are submitted together. The EPA can approve some of the rules and disapprove the rest as long as the rules that are disapproved do not affect those that are approved. The disapproval of any part of a required SIP submittal starts the clocks discussed above for sanctions and FIP's.

Limited Approval/Disapproval

In some cases, a submittal may contain certain provisions that meet the applicable requirements of the Act along with other provisions that do not meet the requirements, and the provisions are not separable. Although the submittal may not meet all of the applicable requirements, EPA may want to consider whether the submittal as a whole has a strengthening effect on the SIP. If that is the case, limited approval may be used to approve a rule that strengthens the existing SIP as representing an improvement over what is currently in the SIP and as meeting some of the applicable requirements of the Act.

The Act does not expressly provide for limited approvals.

Rather, EPA is using its "gap-filling" authority under section 301(a) of the Act in conjunction with the section 110(k)(3) approval provision to interpret the Act to provide for this type of approval action.

Through a limited approval, EPA would concurrently, or within a reasonable time thereafter, disapprove the rule, under the relevant provision(s) of Part D, for not meeting all of the applicable requirements of the Act. As with the limited approval action the limited disapproval is a rulemaking action, and it is subject to notice and comment. Under section 110(k), EPA must take final rulemaking action on SIP submittals within 12 months of the date EPA determines the submittal is complete or the submittal is automatically deemed to be complete if EPA fails to make a completeness determination. As a general matter, although the statute directs EPA to act within that timeframe, EPA's failure to finalize the disapproval portion of the action within that 12-month timeframe will not affect the validity of any prior or subsequent limited approval or limited disapproval.[1] The EPA's failure to take action prior to the expiration of the 12-month period could, however, subject EPA to a lawsuit to compel such an action.

A key distinction between the limited approval and a partial approval is that under a limited approval EPA's approval action goes to the entire rule. In other words, although portions of a rule prevent EPA from finding that the rule meets a certain requirement of the Act, EPA believes that the rule, as a whole, strengthens the SIP. Therefore, EPA approves the entire rule--even those portions that prohibit full approval. Likewise, when EPA issues the limited disapproval, the disapproval applies to the entire rule as failing to meet a specific requirement of the Act. The rule remains a part of the SIP, however, under the limited disapproval, because the rule strengthens the SIP. The disapproval only applies to whether the submittal meets a specific requirement of the Act and does not affect incorporation of the rule into the approved, federally enforceable SIP.

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[1] The March 22, 1991 memorandum from John Calcagni discussed the potential impact of Abramowitz v. U.S. E.P.A., 832, F. 2d 1071 (9th Cir. 1988), on EPA's decision to split the approval and disapproval portions of a limited approval. After reevaluating that case, we believe it may have a narrower impact than initially described and, therefore, generally would not impact the timing of limited approval/disapproval actions.

The primary advantage to using the limited approval approach is to make the State submittal federally enforceable and to increase the SIP's potential to achieve additional reductions. Therefore, limited approval should not be used to approve any rule that is unenforceable for all situations--for example, a rule that lacks a test method. These rules and any other rules that do not have an overall strengthening effect on the SIP should be disapproved. Limited approval can be used, however, where the rule is unenforceable for some limited number of situations but is enforceable for the majority of situations, if the rule, as a whole, strengthens the SIP.

The disapproval coinciding with (or following) the limited approval also starts the sanctions and FIP clocks discussed above. With the limited approval EPA may or may not have a commitment from the State to correct the deficiency. The EPA may choose to use the limited approval approach (instead of conditional approval) in the case where the State has submitted a commitment as part of a rule but EPA has reason to believe that the State will not be able to meet the commitment (as discussed below). Where a limited approval/disapproval approach is taken, the notice of proposed rulemaking (NPR) should clearly identify which requirements have not been met and what action would be required on the part of the State to meet those requirements.

Conditional Approval

Under section 110(k)(4) of the Act EPA may conditionally approve a plan based on a commitment from the State to adopt specific enforceable measures within 1 year from the date of approval. If the State fails to meet its commitment within the 1-year period, the approval is treated as a disapproval. We expect that conditional approvals will be used only in rare situations that merit special consideration. We will evaluate specific types of SIP submittals [e.g., reasonably available control technology (RACT) catch-ups, particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM-10) SIP's] to determine whether certain elements of that type of submittal, or that type of submittal as a whole, merit conditional approval. For this reason and to ensure consistency, Regions should not use conditional approvals without input from Headquarters as to whether such an approach is appropriate. Furthermore, as any statutory deadline approaches, we may issue guidance regarding the appropriate use of conditional approval with respect to that specific requirement.

Once a determination has been made that a specific type of submittal can be considered for conditional approval, Regions

must make a determination of whether an individual State submittal should be conditionally approved. The first consideration should be whether the State has made (or agrees to make) a commitment to adopt specific enforceable measures within 1 year of EPA approval. The commitment must be made in writing by the party responsible for adopting the specified measures before the plan is conditionally approved, and the commitment must be submitted by the State.[2]

In addition, to the extent that the commitment materially alters the existing rule (in respects that the public could not reasonably have anticipated would result from the public review of the existing rule), or is a commitment to adopt an entire rule or set of rules, the commitment must be a SIP revision submittal by the State. In many cases, the determination of whether the commitment materially alters the underlying rule may be based on whether a similar issue was raised during the earlier State proceedings on the submitted rule. In general, each commitment will need to be examined to determine whether it materially alters the submitted rule. As with any SIP revision, in order for EPA to accept the commitment as a SIP revision, the State must have provided notice and public hearing on the submitted commitment. However, EPA has the discretion to parallel process commitments and in limited circumstances may propose conditional approval of the commitment and allow the State process to proceed on a parallel track.

As a general matter, the greater the extent to which a submittal is lacking in important plan elements, the less appropriate the use of conditional approval may be. It should be noted, however, that there may be circumstances under which EPA would accept a SIP revision consisting of a commitment only (without specifically adopted rules) as a candidate for conditional approval. In such cases, the commitment should also be accompanied by a work plan detailing any specific measures to be adopted, the steps that will be taken to adopt the measures,

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[2] Although the commitment must identify the measures to be adopted and contain a schedule for adopting such measures, it is not necessary for the commitment itself to be enforceable in a State court.

and the schedule for adoption of those measures. As stated earlier, a submittal that consists entirely of a commitment will be considered a SIP revision that is subject to the State process for submitting SIP revisions, e.g., notice and a public hearing.

Where the submittal contains specifically adopted rules that need some revisions or corrections to be fully-approvable, the commitment may not need to be as comprehensive. The commitment should, however, be as explicit as possible concerning the measures that will be adopted, the steps that will be taken to adopt the measures, and the schedule for adoption of those measures.

Because the conditional approval relies on a commitment from the State, EPA would need some level of confidence that the State would be able to meet such a commitment. In making a determination as to whether a State could reasonably be expected to meet its commitment, EPA would need to consider a number of factors such as:

- the amount of technical work necessary for the measures to be adopted;
- whether adoption of the measures is expected to be controversial;
- the average length of the State adoption process;
- how far along in the process the State is; and
- the State's past track record.

It should be noted that these are only some of the factors that should be considered. Each Region, in making a determination regarding the credibility of the State's commitment, may have to look at a number of other factors. The Region should clearly explain, either in the NPR or in a technical support document, the rationale for these determinations.

In addition to the determination of whether the State's commitment is credible, the Region must make a determination as to whether it is appropriate to conditionally approve a revision on the merits of that revision. Conditional approval might typically be used in the same types of situations as the limited approval. As with the limited approval, one of the main advantages of the conditional approval approach is to make the State submittal (where the submittal contains control requirements and not just a commitment to adopt enforceable measures) federally enforceable and to increase its potential to achieve additional reductions. Because the conditionally approved submittal will become a part of the SIP, the Region

should be certain that the approval of the commitment will not weaken the existing SIP. The Region may also want to consider when the plan (or plan element) that has been submitted was due.

The NPR for a conditional approval should clearly identify which requirements are the subject of the commitment and, therefore, have not been met. In addition, both the NPR and the State's commitment should clearly identify what action is required on the part of the State. Unlike the limited approval/disapproval, the conditional approval does not immediately start the sanctions and FIP clocks. These clocks start if and when the approval is converted to a disapproval.

There are at least two ways that the conditional approval may be converted to a disapproval.[3] First, if the State fails to adopt and submit the specified measures by the end of 1 year (from the final conditional approval), or fails to submit anything at all, EPA will have to issue a finding of disapproval but will not have to propose the disapproval. That is because in the original proposed and final conditional approval, EPA will have provided notice and an opportunity for comment on the fact that EPA would directly make the finding of disapproval (by letter) if the State failed to submit anything.[4] Therefore, at the end of 1 year from the conditional approval, the Regional Administrator (RA) will send a letter to the State finding that it had failed to meet its commitment and that the SIP submittal is disapproved. The 18-month clock for sanctions and the 2-year clock for a FIP start as of the date of the letter. Subsequently, a notice to that effect will be published in the Federal Register, and appropriate language will be inserted in the Code of Federal Regulations. Similarly, if EPA receives a submittal addressing the commitment but determines that the submittal is incomplete, the RA will send a letter to the State making such a finding. As with the failure to submit, the sanctions and FIP clocks will begin as of the date of the finding

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[3] It should be noted that this disapproval can be a limited approval/disapproval. In some cases, the Regions may want to use such an approach to retain the enforceability of control measures. The NPR should indicate if this approach is planned.

[4] To provide for this contingency, in the final conditional approval, EPA would need to provide, for example, "If the State fails to make a submittal or makes only an incomplete submittal during the time period for submittal of the rule, EPA will issue a letter to the State which converts the conditional approval to a disapproval."

letter.

Second, where the State does make a complete submittal by the end of the 1-year period, EPA will have to evaluate that submittal to determine if it may be approved and take final action on the submittal within 12 months after the date EPA determines the submittal is complete. If the submittal does not adequately address the deficiencies that were the subject of the conditional approval, and is therefore not approvable, EPA will have to go through notice-and-comment rulemaking to disapprove the submittal. The 18-month clock for sanctions and the 2-year clock for a FIP start as of the date of final disapproval. If EPA determines that the rule is approvable, EPA will propose approval of the rule. In either instance, whether EPA finally approves or disapproves the rule, the conditional approval remains in effect until EPA takes its final action.

It should be noted that EPA will conditionally approve a certain rule only once. Subsequent submittals of the same rule that attempt to correct the same specifically identified problems will not be eligible for conditional approval.

Sanctions and FIP Requirements

Actions that Trigger the Sanctions and FIP Requirements

The actions EPA has the authority to take under the sanctions and FIP provisions of the Act correspond to the different steps EPA must follow as it reviews and processes SIP submittals. As discussed previously, the Act in section 179[5] requires EPA to impose sanctions based on four types of actions (findings[6]) provided in section 179(a):

(1) a finding that a State has failed to submit a SIP, a

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[5] Section 110(m) grants EPA broad authority to apply either sanction listed in section 179(b) " . . . at any time (or at any time after) a finding . . ." under section 179(a) with respect to any portion of the State, with certain exceptions. This memorandum is intended to address the application of sanctions under section 179. The section 179 sanctions apply only to the area for which a finding has been made.

[6] Although subsections (1)-(4) refer to findings, determinations and disapprovals, for simplicity these four actions will be referred to as "findings."

SIP element,[7] or has submitted a SIP or SIP element that does not satisfy the completeness criteria;

(2) that EPA disapproval of a SIP submission for a nonattainment area based on its failure to meet one or more elements required by the Act;

(3) a determination that the State has not made any other submission, has made an inadequate submission (as required by the Act), or that EPA disapproves such a submission; or

(4) a finding that a requirement of an approved plan is not being implemented.

Under section 110(c)(1), EPA is required to promulgate a FIP based on two types of findings:[8]

(1) a finding that a State has failed to make a required submittal or that a submittal does not satisfy the minimum completeness criteria established under section 110(k)(1)(A), or

(2) the EPA disapproval of a SIP submittal in whole or in part.

The Sanctions and FIP Clocks

Although EPA may make any of the findings discussed above to trigger the 179(a) sanctions and 110(c)(1) FIP requirements, these findings do not require the immediate imposition of sanctions or promulgation of a FIP. Instead the Act provides a "clock" for sanctions and FIP's. For plan submittals required under Part D or in response to a SIP call, section 179(a) allows

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[7] Since EPA does not intend to issue a list of such elements per se, to ensure that such findings are consistently applied, findings of failure to submit SIP elements should be decided on a case-by-case basis in conjunction with Headquarters. The basis for the finding should be clear and well-supported.

[8] Since the deficiency is a failure to implement after a State has submitted a plan and EPA has approved it, it is unnecessary for this finding to trigger a requirement that EPA develop the required rule (i.e., prepare a FIP) and section 110(c)(1) does not require it.

for up to 18 months for the State to correct the deficiency that is the subject of a finding or disapproval before EPA is required to impose sanctions. Section 110(c)(1) provides for up to 2 years for the State to correct the deficiency and for EPA to approve a new submittal before EPA is obligated to promulgate a FIP.

The Administrator has delegated the authority to make findings of failure to submit to the RA's. The findings are made via letters from the RA's to State governors or other State officers to whom authority has been delegated. The letter itself triggers the sanctions and FIP clocks. For disapprovals, the Federal Register notice in which EPA takes final action triggers the sanctions and FIP clocks. Findings of nonimplementation have traditionally been processed as rulemaking actions through Headquarters. The sanctions clock will start when EPA makes a finding of nonimplementation in the Federal Register after soliciting comment on the proposal (the FIP clock is not triggered by such a finding). Although the findings of failure to submit and SIP disapproval start both the sanctions and FIP clocks, what is required to stop the clocks differs; therefore, they are discussed separately. Note that in some cases the sanctions clock may be stopped while EPA remains under an obligation to promulgate a FIP.

Sanctions Clock

Under section 179(a), in order to stop the sanctions clock, the State must correct the "deficiency" prompting the finding. The EPA must apply one of the two sanctions available under section 179(b) within 18 months after the date of the finding and both sanctions at 24 months, unless the deficiency has been corrected. Section 179(a) also requires EPA to apply both sanctions after 18 months if EPA finds a lack of good faith on the part of the State.

Attachment 3 provides seven scenarios illustrating how the sanctions clock operates, including examples of what constitutes a deficiency correction (and hence a stopping of the clock). In brief, for purposes of the sanctions clock, findings of failure to submit plans or complete plans are corrected when EPA finds the submittal complete[9] [although the FIP clock is still

[9] Where EPA made a finding of failure to submit and subsequently finds that the State has made a complete submittal for the plan or plan element that was the subject of the finding, the letter that makes the finding of completeness will notify the State that the sanctions clock is stopped as of the date of that

running (see FIP clock discussion)] and disapprovals are corrected when EPA takes final rulemaking action approving the plan. In addition, findings of nonimplementation are corrected when EPA makes a finding in the Federal Register that the State is now implementing that provision.

FIP Clock

Under the FIP provisions, either a SIP must be approved or a FIP must promulgated within 2 years of one of the two findings discussed above. In other words, EPA must approve the State submittal in order to stop the FIP clock. Where the sanctions and FIP clocks were started by EPA disapproval of a plan, the clocks will run concurrently. In this case, to correct the deficiency for purposes of the sanctions clock, the State must make a submittal which EPA finds approvable. Such a determination is not made until EPA issues a final approval of the plan. Final approval of a plan is also what is needed to stop the FIP clock. Attachment 3 provides seven scenarios of how the FIP clock operates.

Available Sanctions

For plan submittals required under Part D or in response to a SIP call, if the State does not correct the specific deficiency within the 18-month period allowed under section 179(a), EPA must apply at least one of the two sanctions available under section 179(b)[10] as described:

(1) Highway funding sanctions. The EPA may impose a prohibition on the approval by the Secretary of Transportation of certain projects, or the awarding of certain grants.

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letter. The Region should periodically announce any such findings that represent corrections of failure to submit in the Federal Register.

[10] In addition, section 179(a) provides for an air pollution grant sanction that applies to grants EPA may award under section 105. However, since it is not a sanction provided under section 179(b), it is not one of the sanctions EPA must impose after the 18-month period.

(2) Offset sanctions. A ratio of at least 2-to-1 will be required for emissions reductions within the nonattainment area to offset emissions from new or modified major facilities (as required under section 173).

Regions should determine which of the sanctions will be applied at the 18- and 24-month milestones on a case-by-case basis. As discussed previously, EPA must apply both sanctions at the 18-month mark if it finds there is a lack of good faith effort. Such a determination should be made on a case-by-case basis in consultation with Headquarters. In addition, once one of the sanctions has been imposed, EPA must impose the second sanctions if the deficiency has not been corrected within 6 months (regardless of the State's efforts). Headquarters will issue a proposal of the sanctions and the Regional Office will issue the final rule imposing sanctions.

Conclusion

General comments on this memorandum should be directed to Pam Johnson of the Regional Operations Branch at (919) 541-5270. Comments related specifically to ozone or carbon monoxide should be directed to Carla Oldham at (919) 541-3347. Comments related to particulate matter, sulfur dioxide, or lead should be directed to Chris Stoneman at (919) 541-0823.

cc: Regional Air Counsels, Regions I-X
Chief, Air Programs Branch, Regions I-X
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William Becker, STAPPA/ALAPCO
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Attachment 1

Example 1

A State submits a SIP revision containing four rules: (1) control requirements for bulk gasoline plants, (2) control requirements for gasoline dispensing facilities (Stage I), (3) leak detection requirements for gasoline tanks trucks, and (4) test methods that apply to these three rules. The EPA review of the rules shows that all of the rules except the Stage I rule meet the applicable requirements of the Act. The Stage I rule fails to require submerged fill loading for all storage tanks. This is inconsistent with EPA's RACT guidance and the State has failed to propose an alternative that it has demonstrated is RACT for the applicable sources.

Partial Approval

Under the partial approval option, EPA can approve the rules for bulk terminals and tank truck leaks, approve the test methods, and disapprove the Stage I rule. These rules are separable from the Stage I rule. Disapproval of the Stage I rule does not affect the stringency of the other three rules. Therefore, the other three rules may be approved under this provision. However, the submittal as a whole would only be partially approved.

Limited Approval of Stage I Rule

Under the limited approval approach, EPA could approve the Stage I rule as being an improvement over what is currently in the SIP and, at the same time or within a reasonable time after the approval (but no later than 12 months after the submittal is complete), disapprove the rule because it does not represent RACT. The sanctions and FIP clocks would start upon the final disapproval of the rule.

Conditional Approval

Alternatively, EPA could conditionally approve the Stage I rule if the State committed to revise the rule, within 1 year of the conditional approval, to require submerged fill loading. If the State then failed to make such a revision, EPA would issue a finding converting the conditional approval to a disapproval.

Example 2

If in example 1 the first three rules (containing control requirements) are all approvable but the fourth (containing the test methods) is either deficient or has not been submitted, then the submittal would have to be handled differently. Because a test method is critical in determining the stringency of a control requirement and is needed for the requirements to be enforceable, these rules cannot be considered separable and,

therefore, partial approval would not be an option. In addition, because the control requirements will not be enforceable without a test method, it would not be appropriate to use either the limited or conditional approval approach.

Example 3

A State submits a SIP revision that contains four PM-10 rules, two for controlling emissions of fugitive dust and two for the control of residential wood combustion. The rules represent reasonable available control measures (RACM) and include (1) paving or stabilizing unpaved roads, (2) developing a traffic reduction plan for unpaved roads, (3) a mandatory episode curtailment program for residential wood combustion, and (4) encouraging changeover to new source performance standards and wood stoves. The third rule is deficient in that it does not provide a communication strategy on which the curtailment program is dependent.

Partial Approval

The EPA may approve the three rules which satisfy RACM but disapprove the episode curtailment program as failing to meet the RACM requirement. These rules are separable because disapproval of the curtailment program will not have any effect on the stringency or enforceability of the remaining rules.

Limited Approval

The EPA may approve the episode curtailment plan as strengthening the SIP by providing enforceable measures in a SIP which currently has no curtailment program. At the same time or within a reasonable time after the approval (but no later than 12 months after the submittal is complete), EPA must disapprove the rule as not representing RACM. Final disapproval of the rule would start the sanctions and FIP clocks.

Conditional Approval

The EPA may conditionally approve the rule if the State submits a commitment to submit a revised rule within 1 year of the approval. If the State then failed to make such a revision, EPA would issue a finding converting the conditional approval to a disapproval.

Attachment 2

Type of Approval	Separability	Commitment	Act Requirements	SIP Strengthening
Partial	rules must be separable	no commitment necessary	part to be approved must meet all applicable requirements	part to be approved must strengthen the SIP
Limited	deficient portion of submittal is not separable	no commitment necessary	does not have to meet <u>all</u> applicable requirements	submittal as a whole must strengthen the SIP
Conditional	deficient portion of submittal is not separable	State must commit to correct within 1 year	does not have to meet <u>all</u> applicable requirements	submittal as a whole must strengthen the SIP

Attachment 3: Sanctions and FIP Clocks Scenarios

Scenario 1: The EPA receives a SIP and finds it incomplete prior to the statutory due date of the SIP.

Although a finding that the State submitted an incomplete SIP is one of the section 179(a) findings, the sanctions and FIP clocks will not begin to run until after a submittal is due. This is because the finding must be based on the failure to submit a complete required SIP or SIP element and the submittal is not required until it is due under the statute. If a SIP submitted prior to a due date is still incomplete by the due date, then EPA will notify the State by letter that the plan remains incomplete and that the 18-month sanctions clock and the 2-year FIP clock have started.

Scenario 2: The EPA receives a SIP and finds it incomplete on or after the statutory due date of the SIP.

If EPA receives a SIP and finds it incomplete pursuant to section 110(k) on or after the statutory due date of the SIP, then, as in scenario 1, the State has failed to make a complete submittal under section 179(a). The EPA will notify the State by letter that the plan is incomplete and that the 18-month sanctions clock and the 2-year FIP clock have started.

Scenario 3: The EPA receives no submittal at the due date.

If EPA receives no submittal from a State to meet a statutory due date, then it may make a finding of failure to submit under section 179(a)(1), triggering the 18-month sanctions clock and the 2-year FIP clock.

Scenario 4: After the due date, EPA receives a SIP for which it originally made a finding of failure to submit.

Upon receiving the plan, the sanctions clock will continue to run during the completeness review and be stopped if EPA finds the plan complete and continue if EPA finds the plan incomplete. If the 18 months elapse during the time EPA is doing its completeness review, EPA will not impose sanctions unless it determines the plan incomplete. If sanctions have been imposed prior to the State's submittal, the sanctions will remain in place until EPA determines the submittal complete.

The FIP clock continues to run while EPA makes its completeness determination.

Scenario 5: The EPA originally makes a finding of failure to submit, then receives a SIP, finds it complete, but disapproves it in final rulemaking.

Upon a determination that the SIP is complete, the State corrects the deficiency that prompted the finding of nonsubmittal and the sanctions clock stops. A new sanctions clock will start upon the final SIP disapproval rulemaking. The new sanctions clock will not stop until EPA has taken final action to approve the revised SIP submittal.

Even after the submittal is determined to be complete, EPA remains under obligation to promulgate a FIP. Therefore, the disapproval of the SIP does not start a new FIP clock.

Scenario 6: The EPA originally makes a finding of failure to submit, then receives a SIP, finds it complete, and approves it in final rulemaking.

Upon a determination that the SIP is complete, the State corrects the deficiency prompting the finding of nonsubmittal and the sanctions clock stops. The EPA remains under obligation to promulgate a FIP until EPA takes final rulemaking action to approve the SIP.

Scenario 7: The EPA finds that a State has failed to implement a SIP or SIP provision.

The EPA will make a finding of nonimplementation in the Federal Register after soliciting comment on the proposal. The sanctions clock will start upon EPA taking final action and stop when EPA makes a finding in the Federal Register after notice-and-comment rulemaking that the State has corrected the deficiency that prompted the finding. A finding of nonimplementation does not start a FIP clock.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

4 SEP 1992

MEMORANDUM

SUBJECT: Procedures for Processing Requests to Redesignate Areas to Attainment

FROM: John Calcagni, Director
Air Quality Management Division (MD-15)

TO: Director, Air, Pesticides and Toxics Management Division, Regions I and IV
Director, Air and Waste Management Division, Region II
Director, Air, Radiation and Toxics Division, Region III
Director, Air and Radiation Division, Region V
Director, Air, Pesticides and Toxics Division, Region VI
Director, Air and Toxics Division, Regions VII, VIII, IX, and X

Purpose

The Office of Air Quality Planning and Standards (OAQPS) expects that a number of redesignation requests will be submitted in the near future. Thus, Regions will need to have guidance on the applicable procedures for handling these requests, including maintenance plan provisions. This memorandum, therefore, consolidates the Environmental Protection Agency's (EPA's) guidance regarding the processing of requests for redesignation of nonattainment areas to attainment for ozone (O_3), carbon monoxide (CO), particulate matter (PM-10), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and lead (Pb). Regions should use this guidance as a general framework for drafting Federal Register notices pertaining to redesignation requests. Special concerns for areas seeking redesignation from unclassifiable to attainment will be addressed on a case-by-case basis.

Background

Section 107(d)(3)(E) of the Clean Air Act, as amended, states that an area can be redesignated to attainment if the following conditions are met:

1. The EPA has determined that the national ambient air quality standards (NAAQS) have been attained.

2. The applicable implementation plan has been fully approved by EPA under section 110(k).

3. The EPA has determined that the improvement in air quality is due to permanent and enforceable reductions in emissions.

4. The State has met all applicable requirements for the area under section 110 and Part D.

5. The EPA has fully approved a maintenance plan, including a contingency plan, for the area under section 175A.

Each of these criteria is discussed in more detail in the following paragraphs. Particular attention is given to maintenance plan provisions at the end of this document since maintenance plans constitute a new requirement under the amended Clean Air Act. Exceptions to the guidance will be considered on a case-by-case basis.

1. Attainment of the Standard

The State must show that the area is attaining the applicable NAAQS. There are two components involved in making this demonstration which should be considered interdependently. The first component relies upon ambient air quality data. The data that are used to demonstrate attainment should be the product of ambient monitoring that is representative of the area of highest concentration. These monitors should remain at the same location for the duration of the monitoring period required for demonstrating attainment. The data should be collected and quality-assured in accordance with 40 CFR 58 and recorded in the Aerometric Information Retrieval System (AIRS) in order for it to be available to the public for review. For purposes of redesignation, the Regional Office should verify that the integrity of the air quality monitoring network has been preserved.

For PM-10, an area may be considered attaining the NAAQS if the number of expected exceedances per year, according to 40 CFR 50.6, is less than or equal to 1.0. For O_3, the area must show that the average annual number of expected exceedances, according to 40 CFR 50.9, is less than or equal to 1.0 based on data from all monitoring sites in the area or its affected downwind environs. In making this showing, both PM-10 and O_3 must rely on 3 complete, consecutive calendar years of quality-assured air quality monitoring data, collected in accordance with 40 CFR 50, Appendices H and K. For CO, an area may be considered attaining the NAAQS if there are no violations, as determined in accordance

with 40 CFR 50.8, based on 2 complete, consecutive calendar years of quality-assured monitoring data. For SO_2, according to 40 CFR 50.4, an area must show no more than one exceedance annually and for Pb, according to section 50.12, an area may show no exceedances on a quarterly basis.

The second component relies upon supplemental EPA-approved air quality modeling. No such supplemental modeling is required for O_3 nonattainment areas seeking redesignation. Modeling may be necessary to determine the representativeness of the monitored data. For pollutants such as SO_2 and CO, a small number of monitors typically is not representative of areawide air quality or areas of highest concentration. When dealing with SO_2, Pb, PM-10 (except for a limited number of initial moderate nonattainment areas), and CO (except moderate areas with design values of 12.7 parts per million or lower at the time of passage of the Clean Air Act Amendments of 1990), dispersion modeling will generally be necessary to evaluate comprehensively sources' impacts and to determine the areas of expected high concentrations based upon current conditions. Areas which were designated nonattainment based on modeling will generally not be redesignated to attainment unless an acceptable modeling analysis indicates attainment. Regions should consult with OAQPS for further guidance addressing the need for modeling in specific circumstances.

2. State Implementation Plan (SIP) Approval

The SIP for the area must be fully approved under section 110(k),[1] and must satisfy all requirements that apply to the area. It should be noted that approval action on SIP elements and the redesignation request may occur simultaneously. An area cannot be redesignated if a required element of its plan is the subject of a disapproval; a finding of failure to submit or to implement the SIP; or partial, conditional, or limited approval. However, this does not mean that earlier issues with regard to the SIP will be reopened. Regions should not reconsider those things that have already been approved and for which the Clean Air Act Amendments did not alter what is required. In contrast, to the extent the Amendments add a requirement or alter an existing requirement so that it adds something more, Regions should consider those issues. In addition, requests from areas known to be affected by dispersion techniques which are inconsistent with EPA guidance will continue to be considered unapprovable under section 110 and will not qualify for redesignation.

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[1]Section 110(k) contains the requirements for EPA action on plan submissions. It addresses completeness, deadlines, full and partial approval, conditional approval, and disapproval.

3. Permanent and Enforceable Improvement in Air Quality

The State must be able to reasonably attribute the improvement in air quality to emission reductions which are permanent and enforceable.[2] Attainment resulting from temporary reductions in emission rates (e.g., reduced production or shutdown due to temporary adverse economic conditions) or unusually favorable meteorology would not qualify as an air quality improvement due to permanent and enforceable emission reductions.

In making this showing, the State should estimate the percent reduction (from the year that was used to determine the design value for designation and classification) achieved from Federal measures such as the Federal Motor Vehicle Control Program and fuel volatility rules as well as control measures that have been adopted and implemented by the State. This estimate should consider emission rates, production capacities, and other related information to clearly show that the air quality improvements are the result of implemented controls. The analysis should assume that sources are operating at permitted levels (or historic peak levels) unless evidence is presented that such an assumption is unrealistic.

4. Section 110 and Part D Requirements

For the purposes of redesignation, a State must meet all requirements of section 110 and Part D that were applicable prior to submittal of the complete redesignation request. When evaluating a redesignation request, Regions should not consider whether the State has met requirements that come due under the Act after submittal of a complete redesignation request.[3]

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[2]This is consistent with EPA's existing policy on redesignations as stated in an April 21, 1983 memorandum titled "Section 107 Designation Policy Summary." This memorandum states that in order for an area to be redesignated to attainment, the State must show that "actual enforceable emission reductions are responsible for the recent air quality improvement." This element of the policy retains its validity under the amended Act pursuant to section 193. [Note: other aspects of the April 21, 1983 memorandum have since been superseded by subsequent memorandums; interested parties should consult with OAQPS before relying on these aspects, e.g. those relating to required years of air quality data.]

[3]Under section 175A(c), however, the requirements of Part D remain in force and effect for the area until such time as it is redesignated. Upon redesignation to attainment, the requirements that became due under section 175A(c) after submittal of the complete redesignation request would no longer be applicable.

However, any requirements that came due prior to submittal of the redesignation request must be fully approved into the plan at or before the time EPA redesignates the area.

To avoid confusion concerning what requirements will be applicable for purposes of redesignation, Regions should encourage States to work closely with the appropriate Regional Office early in the process. This will help to ensure that a redesignation request submitted by the State has a high likelihood of being approved by EPA. Regions should advise States of the practical planning consequences if EPA disapproves the redesignation request or if the request is invalidated because of violations recorded during EPA's review. Under such circumstances, EPA does not have the discretion to adjust schedules for implementing SIP requirements. As a result, an area may risk sanctions and/or Federal implementation plan implementation that could result from failure to meet SIP submittal or implementation requirements.

a. Section 110 Requirements

Section 110(a)(2) contains general requirements for nonattainment plans. Most of the provisions of this section are the same as those contained in the pre-amended Act. We will provide guidance on these requirements as needed.[4]

b. Part D Requirements

Part D consists of general requirements applicable to all areas which are designated nonattainment based on a violation of the NAAQS. The general requirements are followed by a series of subparts specific to each pollutant. The general requirements appear in subpart 1. The requirements relating to O_3, CO, PM-10, SO_2, NO_2, and Pb appear in subparts 2 through 5. In those instances where an area is subject to both the general nonattainment provisions in subpart 1 as well as one of the pollutant-specific subparts, the general provisions may be subsumed within, or superseded by, the more specific requirements of subparts 2 through 5.

If an area was not classified under section 181 for O_3, or section 186 for CO, then that area is only subject to the provisions of subpart 1, "Nonattainment Areas in General." In addition to relevant provisions in subpart 1, an O_3 and CO area, which is classified, must meet all applicable requirements in subpart 2, "Additional Provisions for Ozone Nonattainment Areas," and subpart 3, "Additional Provisions for Carbon Monoxide

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[4]General guidance regarding the requirements for SIP's may be found in the "General Preamble to Title I of the 1990 Clean Air Act Amendments," 57 FR 13498 (April 16, 1992).

Nonattainment Areas," respectively, before the area may be redesignated to attainment. All PM-10 nonattainment areas (whether classified as moderate or serious) must similarly meet the applicable general provisions of subpart 1 and the specific PM-10 provisions in subpart 4, "Additional Provisions for Particulate Matter Nonattainment Areas." Likewise, SO_2, NO_2, and Pb nonattainment areas are subject to the applicable general nonattainment provisions in subpart 1 as well as the more specific requirements in subpart 5, "Additional Provisions for Areas Designated Nonattainment for Sulfur Oxides, Nitrogen Dioxide, and Lead."

i. Section 172(c) Requirements

This section contains general requirements for nonattainment plans. A thorough discussion of these requirements may be found in the General Preamble to Title I [57 FR 13498 (April 16, 1992)]. The EPA anticipates that areas will already have met most or all of these requirements to the extent that they are not superseded by more specific Part D requirements. The requirements for reasonable further progress, identification of certain emissions increases, and other measures needed for attainment will not apply for redesignations because they only have meaning for areas not attaining the standard. The requirements for an emission inventory will be satisfied by the inventory requirements of the maintenance plan. The requirements of the Part D new source review program will be replaced by the prevention of significant deterioration (PSD) program once the area has been redesignated. However, in order to ensure that the PSD program will become fully effective immediately upon redesignation, either the State must be delegated the Federal PSD program or the State must make any needed modifications to its rules to have the approved PSD program apply to the affected area upon redesignation.

ii. Conformity

The State must work with EPA to show that its SIP provisions are consistent with section 176(c)(4) conformity requirements. The redesignation request should include conformity procedures, if the State already has these procedures in place. Additionally, we currently interpret the conformity requirement to apply to attainment areas. However, EPA has not yet issued its conformity regulations specifying what areas are subject to the conformity requirement. Therefore, if a State does not have conformity procedures in place at the time that it submits a redesignation request, the State must commit to follow EPA's conformity regulation upon issuance, as applicable. If the State submits the redesignation request subsequent to EPA's issuance of the conformity regulations, and the conformity requirement became applicable to the area prior to submission,

the State must adopt the applicable conformity requirements before EPA can redesignate the area.

5. Maintenance Plans

Section 107(d)(3)(E) of the amended Act stipulates that for an area to be redesignated, EPA must fully approve a maintenance plan which meets the requirements of section 175A. A State may submit both the redesignation request and the maintenance plan at the same time and rulemaking on both may proceed on a parallel track. Maintenance plans may, of course, be submitted and approved by EPA before a redesignation is requested. However, according to section 175A(c), pending approval of the maintenance plan and redesignation request, all applicable nonattainment area requirements shall remain in place.

Section 175A defines the general framework of a maintenance plan. The maintenance plan will constitute a SIP revision and must provide for maintenance of the relevant NAAQS in the area for at least 10 years after redesignation. Section 175A further states that the plan shall contain such additional measures, if any, as may be necessary to ensure such maintenance. Because the Act requires a demonstration of maintenance for 10 years after an area is redesignated (not 10 years after submittal of a redesignation request), the State should plan for some lead time for EPA action on the request. In other words, the maintenance demonstration should project maintenance for 10 years, beginning from a date which factors in the time necessary for EPA review and approval action on the redesignation request. In determining the amount of lead time to allow, States should consider that section 107(d)(3)(D) grants the Administrator up to 18 months from receipt of a complete submittal to process a redesignation request. The statute also requires the State to submit a revision of the SIP 8 years after the original redesignation request is approved to provide for maintenance of the NAAQS for an additional 10 years following the first 10-year period [see section 175A(b)].

In addition, the maintenance plan shall contain such contingency measures as the Administrator deems necessary to ensure prompt correction of any violation of the NAAQS [see section 175A(d)]. The Act provides that, at a minimum, the contingency measures must include a requirement that the State will implement all measures contained in the nonattainment SIP prior to redesignation. Failure to maintain the NAAQS and triggering of the contingency plan will not necessitate a revision of the SIP unless required by the Administrator, as stated in section 175A(d).

The following is a list of core provisions that we anticipate will be necessary to ensure maintenance of the relevant NAAQS in an area seeking redesignation from

nonattainment to attainment. We therefore recommend that States seeking redesignation of a nonattainment area consider these provisions. However, any final EPA determination regarding the adequacy of a maintenance plan will be made following review of the plan submittal in light of the particular circumstances facing the area proposed for redesignation and based on all relevant information available at the time.

a. Attainment Inventory

The State should develop an attainment emissions inventory to identify the level of emissions in the area which is sufficient to attain the NAAQS.[5] This inventory should be consistent with EPA's most recent guidance on emission inventories for nonattainment areas available at the time and should include the emissions during the time period associated with the monitoring data showing attainment.[6]

Source size thresholds are 100 tons/year for SO_2, NO_2, and PM-10 areas, and 5 tons/year for Pb based upon 40 CFR 51.100(k) and 51.322, as well as established practice for AIRS data. The source size threshold for serious PM-10 areas is 70 tons/year

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[5]Where the State has made an adequate demonstration that air quality has improved as a result of the SIP (as discussed previously), the attainment inventory will generally be the actual inventory at the time the area attained the standard.

[6]The EPA's current guidance on the preparation of emission inventories for O_3 and CO nonattainment areas is contained in the following documents: "Procedures for the Preparation of Emission Inventories for Carbon Monoxide and Precursors of Ozone: Volume I" (EPA-450/4-91-016), "Procedures for the Preparation of Emission Inventories for Carbon Monoxide and Precursors of Ozone: Volume II" (EPA-450/4-91-014), "Emission Inventory Requirements for Ozone State Implementation Plans" (EPA-450/4-91-010), "Emission Inventory Requirements for Carbon Monoxide Implementation Plans" (EPA-450/4-91-011), "Guideline for Regulatory Application of the Urban Airshed Model" (EPA-450/4-91-013), "Procedures for Emission Inventory Preparation: Volume IV, Mobile Sources" (EPA-450/4-81-026d), and "Procedures for Preparing Emission Inventory Projections" (EPA-450/4-91-019). The EPA does not currently have specific guidance on attainment emissions inventories for SO_2. In lieu thereof, States are referred to the guidance on emissions data to be used as input to modeling demonstrations, contained in Table 9.1 of EPA's "Guideline on Air Quality Models (Revised)" (EPA-450/2-78-027R), July 1987, which is generally applicable to all criteria pollutants. Emission inventory procedures and requirements documents are currently being prepared by OAQPS for PM-10 and Pb; these documents are due for release by summer 1992.

according to Clean Air Act section 189(b)(3). However, the inventory should include sources below these size thresholds if these smaller sources were included in the SIP attainment demonstration. Where sources below the 100, 70, and 5 tons/year-size thresholds (e.g., areas with smaller source size definitions) are subject to a State's minor source permit program, these sources need only be addressed in the aggregate to the extent that they result in areawide growth.

For O_3 nonattainment areas, the inventory should be based on actual "typical summer day" emissions of O_3 precursors (volatile organic compounds and nitrogen oxides) during the attainment year. This will generally correspond to one of the periodic inventories required for nonattainment areas to reconcile milestones. For CO nonattainment areas, the inventory should be based on actual "typical CO season day" emissions for the attainment year. This will generally correspond to one of the periodic inventories required for nonattainment areas.

b. Maintenance Demonstration

A State may generally demonstrate maintenance of the NAAQS by either showing that future emissions of a pollutant or its precursors will not exceed the level of the attainment inventory, or by modeling to show that the future mix of sources and emission rates will not cause a violation of the NAAQS. Under the Clean Air Act, many areas are required to submit modeled attainment demonstrations to show that proposed reductions in emissions will be sufficient to attain the applicable NAAQS. For these areas, the maintenance demonstration should be based upon the same level of modeling. In areas where no such modeling was required, the State should be able to rely on the attainment inventory approach. In both instances, the demonstration should be for a period of 10 years following the redesignation.

Where modeling is relied upon to demonstrate maintenance, each plan should contain a summary of the air quality concentrations expected to result from application of the control strategy. In the process, the plan should identify and describe the dispersion model or other air quality model used to project ambient concentrations (see 40 CFR 51.46).

In either case, to satisfy the demonstration requirement the State should project emissions for the 10-year period following redesignation, either for the purpose of showing that emissions will not increase over the attainment inventory or for conducting modeling.[7] The projected inventory should consider future growth, including population and industry, should be consistent

[7]Guidance for projecting emissions may be found in the emissions inventory guidance cited in footnote 6.

with the attainment inventory, and should document data inputs and assumptions. All elements of the demonstration (e.g., emission projections, new source growth, and modeling) should be consistent with current EPA modeling guidance.[8] For O_3 and CO, the projected emissions should reflect the expected actual emissions based on enforceable emission rates and typical production rates.

For CO, a State should address the areawide component of the maintenance demonstration either by showing that future CO emissions will not increase or by conducting areawide modeling. Preferably, the State should carry out hot-spot modeling that is consistent with the Guideline on Air Quality Models (Revised), in order to demonstrate maintenance of the NAAQS. In particular, if the nonattainment problem is related to a pattern of hot-spots then hot-spot modeling should generally be conducted. However, hot-spot modeling is not automatically required. For example, if the nonattainment problem was related solely to stationary point sources, or if highway improvements have been implemented and the associated emission reductions and travel characteristics can be qualitatively documented, then hot-spot modeling is not required. In such cases, adequate documentation as well as the concurrence of Headquarters is needed.

Any assumptions concerning emission rates must reflect permanent, enforceable measures. In other words, a State generally cannot take credit in the maintenance demonstration for reductions unless there are regulations in place requiring those reductions or the reductions are otherwise shown to be permanent. Therefore, the State will be expected to maintain its implemented control strategy despite redesignation to attainment, unless such measures are shown to be unnecessary for maintenance or are replaced with measures that achieve equivalent reductions (see additional discussion under "Contingency Plan"). Emission reductions from source shutdowns can be considered permanent and enforceable to the extent that those shutdowns have been reflected in the SIP and all applicable permits have been modified accordingly.

Modeling used to demonstrate attainment may be relied upon in the maintenance demonstration where the modeling conforms to current EPA guidance and where the State has projected no significant changes in the modeling inputs during the intervening time. Where the original attainment demonstration may no longer be relied upon, States will be expected to remodel using current

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[8]The EPA-approved modeling guidance may be found in the following documents: "Guideline on Air Quality Models (Revised)," OAQPS, RTP, NC (EPA-450/2-78-027R), July 1986; and "PM-10 SIP Development Guideline," OAQPS, RTP, NC (EPA-450/2-86-001), June 1987.

EPA referenced techniques.[9] This may be necessary where, for example, there has been a change in emissions or a change in the siting of new sources or modifications such that air quality may no longer be accurately represented by the existing modeling.

c. Monitoring Network

Once an area has been redesignated, the State should continue to operate an appropriate air quality monitoring network, in accordance with 40 CFR Part 58, to verify the attainment status of the area. The maintenance plan should contain provisions for continued operation of air quality monitors that will provide such verification. In cases where measured mobile source parameters (e.g., vehicle miles traveled congestion) have changed over time, the State may also need to perform a saturation monitoring study to determine the need for, and location of, additional permanent monitors.

d. Verification of Continued Attainment

Each State should ensure that it has the legal authority to implement and enforce all measures necessary to attain and to maintain the NAAQS. Sections 110(a)(2)(B) and (F) of the Clean Air Act, as amended, and regulations promulgated at 40 CFR 51.110(k), suggest that one such measure is the acquisition of ambient and source emission data to demonstrate attainment and maintenance.

Regardless of whether the maintenance demonstration is based on a showing that future emission inventories will not exceed the attainment inventory or on modeling, the State submittal should indicate how the State will track the progress of the maintenance plan. This is necessary due to the fact that the emission projections made for the maintenance demonstration depend on assumptions of point and area source growth.

One option for tracking the progress of the maintenance demonstration, provided here as an example, would be for the State to periodically update the emissions inventory. In this case, the maintenance plan should specify the frequency of any planned inventory updates. Such an update could be based, in part, on the annual AIRS update and could indicate new source growth and other changes from the attainment inventory (e.g., changes in vehicle miles travelled or in traffic patterns). As an alternative to a complete update of the inventory, the State may choose to do a comprehensive review of the factors that were used in developing the attainment inventory to show no significant change. If this review does show a significant change, the State should then perform an update of the inventory.

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[9] See references for modeling guidance cited in footnote 8.

Where the demonstration is based on modeling, an option for tracking progress would be for the State to periodically (typically every 3 years) reevaluate the modeling assumptions and input data. In any event, the State should monitor the indicators for triggering contingency measures (as discussed below).

e. Contingency Plan

Section 175A of the Act also requires that a maintenance plan include contingency provisions, as necessary, to promptly correct any violation of the NAAQS that occurs after redesignation of the area. These contingency measures are distinguished from those generally required for nonattainment areas under section 172(c)(9) and those specifically required for O_3 and CO nonattainment areas under sections 182(c)(9) and 187(a)(3), respectively. For the purposes of section 175A, a State is not required to have fully adopted contingency measures that will take effect without further action by the State in order for the maintenance plan to be approved. However, the contingency plan is considered to be an enforceable part of the SIP and should ensure that the contingency measures are adopted expediently once they are triggered. The plan should clearly identify the measures to be adopted, a schedule and procedure for adoption and implementation, and a specific time limit for action by the State. As a necessary part of the plan, the State should also identify specific indicators, or triggers, which will be used to determine when the contingency measures need to be implemented.

Where the maintenance demonstration is based on the inventory, the State may, for example, identify an "action level" of emissions as the indicator. If later inventory updates show that the inventory has exceeded the action level, the State would take the necessary steps to implement the contingency measures. The indicators would allow a State to take early action to address potential violations of the NAAQS before they occur. By taking early action, States may be able to prevent any actual violations of the NAAQS and, therefore, eliminate the need on the part of EPA to redesignate an area to nonattainment.

Other indicators to consider include monitored or modeled violations of the NAAQS (due to the inadequacy of monitoring data in some situations). It is important to note that air quality data in excess of the NAAQS will not automatically necessitate a revision of the SIP where implementation of contingency measures is adequate to address the cause of the violation. The need for a SIP revision is subject to the Administrator's discretion.

The EPA will review what constitutes a contingency plan on a case-by-case basis. At a minimum, it must require that the State will implement all measures contained in the Part D nonattainment

plan for the area prior to redesignation [see section 175A(d)]. This language suggests that a State may submit a SIP revision at the time of its redesignation request to remove or reduce the stringency of control measures. Such a revision can be approved by EPA if it provides for compensating equivalent reductions. A demonstration that measures are equivalent would have to include appropriate modeling or an adequate justification. Alternatively, a State might be able to demonstrate (through EPA-approved modeling) that the measures are not necessary for maintenance of the standard. In either case, the contingency plan would have to provide for implementation of any measures that were reduced or removed after redesignation of the area.

Summary

As stated previously, this memorandum consolidates EPA's redesignation and maintenance plan guidance and Regions should rely upon it as a general framework in drafting Federal Register notices. It is strongly suggested that the Regional Offices share this document with the appropriate States. This should give the States a better understanding of what is expected from a redesignation request and maintenance plan under existing policy. Any necessary changes to existing Agency policy will be made through our action on specific redesignation requests and the review of section 175A maintenance plans for these particular areas, both of which are subject to notice and comment rulemaking procedures. Thus, in applying this memorandum to specific circumstances in a rulemaking, Regions should consider the applicability of the underlying policies to the particular facts and to comments submitted by any person. If your staff members have questions which require clarification, they may contact Sharon Reinders at (919) 541-5284 for O_3- and CO-related issues, and Eric Ginsburg at (919) 541-0877 for SO_2-, PM-10-, and Pb-related issues.

cc: Chief, Air Branch, Regions I-X
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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OCT 2 2007

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Guidance on SIP Elements Required Under Sections 110(a)(1) and (2) for the 1997 8-hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards

FROM: for William T. Harnett, Director
Air Quality Policy Division (C539-01)

TO: Air Division Directors, Regions I-X

The purpose of this memorandum is to provide guidance on the "infrastructure" elements for State Implementation Plans (SIPs) required under section 110(a)(1) and (2) of the Clean Air Act (CAA) for the 1997 8-hour ozone and fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS). Attachment A to this memo provides a list of the basic elements that States must include in their SIPs. To the extent that existing SIPs for ozone and particulate matter already meet these requirements, States need only certify that fact to the Environmental Protection Agency (EPA). To the extent that existing SIPs for ozone and particulate matter fail to address any of these requirements for purposes of the 1997 8-hour ozone or $PM_{2.5}$ NAAQS, States need to make timely SIP submissions to EPA to address these requirements. We anticipate that States will already have approved SIPs in place for ozone that meet the basic requirements of sections 110(a)(1) and (2). For $PM_{2.5}$, however, we anticipate that many States may need to make SIP revisions to ensure that their existing SIPs for prior particulate matter NAAQS are revised to include the new particle size indicator.

Background

On July 18, 1997, the EPA promulgated new and revised NAAQS for ozone and particulate matter. For ozone, EPA revised the NAAQS to provide an 8-hour averaging period (versus a 1-hour averaging period for the pre-existing NAAQS), and set the level of the standard at 0.08 ppm (versus 0.12 ppm for the pre-existing NAAQS). For PM, EPA promulgated a new 24-hour and a new

annual NAAQS for $PM_{2.5}$ (particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers).[1]

Under sections 110(a)(1) and (2) of the CAA, all States are required to submit plans to provide for the implementation, maintenance, and enforcement of the 8-hour ozone and $PM_{2.5}$ standards. Sections 110(a)(1) and (2) require States to address basic SIP requirements, including emissions inventories, monitoring, and modeling to assure attainment and maintenance of the standards. By statute, SIPs meeting the requirements of sections 110(a)(1) and (2) are to be submitted by States within 3 years after promulgation of a new or revised standard. This being the case, States were required to submit such SIPs for the 1997 standards to EPA no later than July 2000. However, intervening litigation over the 1997 8-hour ozone and $PM_{2.5}$ NAAQS, created uncertainty about how to proceed and, to date, States have not submitted SIPs to meet the basic or infrastructure requirements enumerated in sections 110(a)(1) and (2).

In March of 2004, Earth Justice initiated a lawsuit against EPA for failure to take action against States that had not made SIP submissions to meet the requirements of sections 110(a)(1) and (2), i.e., failure to make a "finding of failure to submit." On March 10, 2005, EPA entered into a Consent Decree with Earth Justice that obligates EPA to make official findings whether States have made required SIP submissions by dates certain. The Consent Decree obligates EPA to determine whether States have made SIP submissions required to meet CAA section 110(a)(2)(D)(i) relating to interstate transport by no later than March 15, 2005. The Consent Decree also obligates EPA to make a determination whether States have made submissions necessary to meet the remaining 110(a)(1) and (2) requirements by December 15, 2007, for the 8-hour ozone NAAQS, and by October 5, 2008, for the $PM_{2.5}$ NAAQS.[2] It should be noted that the latter determinations pertain only to whether the submissions are complete, pursuant to section 110(k)(1)(A), and do not constitute EPA approval or disapproval of such submissions. In addition, the determinations required by the Consent Decree explicitly exclude any determinations regarding: (i)

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[1] More recently, on December 18, 2006, EPA again revised the standards for particulate matter, tightening the 24-hour $PM_{2.5}$ standard from 65 micrograms per cubic meter ($\mu g/m^3$) to 35 $\mu g/m,^3$ and retaining the current annual fine particle standard at 15 $\mu g/m^3$. EPA also decided to retain the existing 24-hour PM_{10} standard of 150 $\mu g/m^3$ and to revoke the annual PM_{10}. This guidance document applies only to the SIP submission requirements for the 1997 8-hour Ozone and $PM_{2.5}$ NAAQS. EPA will address SIP requirements for the 2006 NAAQS separately, although the Agency notes that the statutory requirements for SIPs for new or revised NAAQS are comparable.

[2] The dates specified in the Consent Decree reflect the anticipated dates for submission of nonattainment area SIPs for each NAAQS, plus six months for EPA evaluation. EPA presumed that States would make SIP submissions meeting the basic requirements of sections 110(a)(1) and (2) for each NAAQS contemporaneously with, or not later than, SIPs meeting the nonattainment area plan requirements. EPA notes that recent decisions by the U.S. Court of Appeals for the District of Columbia concerning the implementation rule for the 8-hour Ozone NAAQS have affected certain nonattainment area SIP requirements. These judicial decisions do not, however, affect States' obligations under the CAA or EPA's obligations under the Consent Decree concerning the infrastructure SIP requirements of sections 110(a)(1) and (2).

submissions required by section 110(a)(2)(C) to the extent that subsection pertains to a nonattainment area new source permit program in part D Title I of the CAA; and (ii) submissions required by section 110(a)(2)(I) for Part D Title I nonattainment area plans.

In accordance with the Consent Decree, EPA has already published a finding that all States had failed to submit new SIPs addressing interstate transport for the 8-hour ozone and $PM_{2.5}$ NAAQS, as required by section 110(a)(2)(D)(i) of the CAA (70 FR 21147, April 25, 2005). That finding initiated a 2-year deadline for the promulgation of a Federal Implementation Plan (FIP) by EPA for each such State unless, prior to that time, each State makes a submission to meet the requirements of Section 110(a)(2)(D)(i) and EPA approves such submission. On May 12, 2005, EPA published the Clean Air Interstate Rule (CAIR) which identifies the degree to which emissions of SO_2 and NO_x in certain States significantly contribute to nonattainment of, or interfere with maintenance of, the 1997 8-hour ozone and $PM_{2.5}$ NAAQS in downwind States, and the reductions that must be achieved in those States to eliminate such contributions.

On August 15, 2006, EPA issued guidance entitled "Guidance for State Implementation Plan (SIP) Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards." The section 110(a)(2)(D)(i) guidance indicates that States within the CAIR region can satisfy 110(a)(2)(D) by satisfying the requirements of the CAIR, and addresses what other States that are outside of the CAIR region should consider doing to meet the "significant contribution" and "interfere with maintenance" requirements of section 110(a)(2)(D)(i) for the 1997 standards. The section 110(a)(2)(D)(i) guidance also addresses what all States (whether inside or outside of the CAIR region) should consider in making SIP submissions to meet the "prevention of significant deterioration" and "protect visibility" requirements of section 110(a)(2)(D)(i). The SIP submissions addressed by the section 110(a)(2)(D)(i) guidance are those that are necessary to rectify the finding of failure to submit that EPA has already issued for all States for section 110(a)(2)(D)(i).

The guidance contained in this memorandum is intended as a reminder that States must have SIPs for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS that meet all of the requirements of sections 110(a)(1) and (2). Pursuant to the Consent Decree, EPA has an obligation to take action to determine whether States have made such submissions by the dates noted above. Because States should currently be in the process of submitting nonattainment SIPs for the 8-hour ozone standard and working on nonattainment area SIPs for the $PM_{2.5}$ standard, we want to alert them to be sure that their SIPs also meet the basic requirements of sections 110(a)(1) and (2).

Guidance

The EPA believes that the currently-approved section 110 SIPs for ozone may already be adequate in most cases to implement the 8-hour ozone NAAQS. Many of the required section 110(a)(1) and (2) SIP elements relate to the general information and authorities that constitute the "infrastructure" of the ozone air quality management program, and these have been in place since the initial SIPs were submitted in response to the 1970 Clean Air Act. For particulate matter, however, EPA believes that some States may need to adopt language specific to the $PM_{2.5}$ NAAQS to ensure that they have adequate SIP provisions to implement the $PM_{2.5}$ NAAQS, e.g., existing State laws may refer to PM_{10} specifically or to particulate matter more generally, rather than to $PM_{2.5}$. We believe that with one exception, the infrastructure requirements of sections 110(a)(1) and (2) are relatively self explanatory, and past experience with SIPs for other NAAQS should enable States to meet these requirements with assistance from EPA Regions. The one exception is section 110(a)(2)(G) relating to emergency episodes, for which EPA intends to take additional regulatory action to provide necessary numerical limits and concentration levels for emergency episode action plans for $PM_{2.5}$.

States should review and revise, as appropriate, their existing ozone and particulate matter SIPs to ensure that they are adequate to address the 8-hour ozone and $PM_{2.5}$ NAAQS. If a State determines that its existing SIP is adequate, then the State needs to certify, via a letter to the Agency from the Governor or his/her designee, that the existing SIPs contain provisions that address the requirements for the 8-hour ozone and $PM_{2.5}$ NAAQS. If a State determines that its existing ozone or particulate matter SIPs are inadequate, however, then the State needs to submit a SIP revision to make the appropriate changes.

With respect to $PM_{2.5}$, States may find it more advantageous to revise the language in their SIPs to identify "particulate matter" as the pollutant being implemented and define the size fractions as "those that EPA has currently set for the NAAQS" to the extent such an approach would be authorized by State law. This will ensure that the provisions remain adequate in the event that future changes occur to the particulate matter standards. States could also specify both PM_{10} and $PM_{2.5}$ as the size fractions if a State prefers to be more specific.

As an aid to the States in addressing the $PM_{2.5}$ related requirements of Section 110(a)(2)(G) pertaining to emergency episode provisions, EPA intends to take action to revise 40 CFR, Part 51, subpart H (sections 51.150). The rule changes will establish the priority classifications which determine the emergency episode plan requirements for each area and establish a significant harm level (SHL) for $PM_{2.5}$. Until these changes are final, EPA recommends that States rely on relevant information contained in upcoming EPA rule proposals or other EPA-issued interim guidance to satisfy the section 110(a)(2)(G) requirements for $PM_{2.5}$. After EPA issues final rules, EPA will work with States to revise SIP

submissions that were based on interim information, as appropriate. States may wish to take advantage of the parallel processing mechanism for making their section 110(a)(2)(G) submittal in the interim while EPA completes rulemakings on the SHL and the emergency episode plan requirements under 40 CFR 51.150.

The SHL for the 8-hour ozone NAAQS will remain unchanged as 0.60 ppm ozone, 2-hr average, as indicated in 40 CFR Part 51.151. EPA believes that the existing ozone-related provisions of 40 CFR Subpart H remain appropriate. Therefore, EPA expects that for purposes of the 1997 8-hour ozone NAAQS, States need only to confirm that they have existing emergency episode plan provisions consistent with EPA's existing regulatory requirements.

By statute, States are required to make SIP submissions to meet the basic requirements of CAA sections 110(a)(1) and (2) within 3 years after promulgation of any new or revised standards. For the 1997 8-hour ozone and $PM_{2.5}$ standards, this deadline was July 2000. By Consent Decree, as noted above, EPA has agreed to make a determination whether or not States have submitted SIPs to meet these requirements by a date certain. In the case of 8-hour ozone SIPs, this date is December 15, 2007. For $PM_{2.5}$ SIPs, this date is October 15, 2008. In order for EPA to evaluate the submissions adequately, EPA requests that States make their certifications of SIP adequacy or SIP revisions as soon as possible and to the extent feasible sufficiently in advance of these dates to allow EPA time to determine whether complete submissions have been made.

If you have any questions concerning this guidance, please contact Mr. David Sanders at (919) 541-3356. Please ensure that the appropriate air agency officials for States in your Region are made aware of this guidance.

Attachments

cc: Margo Oge, OTAQ
Steve Page, OAQPS
Brian McLean, OAP
Richard Wayland, OAQPS
Lydia Wegman, OAQPS
Peter Tsirigotis, OAQPS

Attachment A: Required Section 110 SIP Elements

The SIP elements listed below are required under section 110(a)(1) and (2). Section 110(a)(1) provides the procedural and timing requirements for SIPs. Section 110(a)(2) lists the basic or "infrastructure" elements that all SIPs must contain. We note that this list is not intended to constitute an interpretation of these provisions, or a change of past practice with respect to these provisions, merely a brief description of the required SIP elements.

Emission limits and other control measures: Section 110(a)(2)(A) requires SIPs to include enforceable emission limits and other control measures, means or techniques, schedules for compliance and other related matters. EPA notes that the specific nonattainment area plan requirements of section 110(a)(2)(I) are subject to the timing requirement of section 172, not the timing requirement of section 110(a)(1), and also that SIPs to meet this section are not covered by the Consent Decree.

Ambient air quality monitoring/data system: Section 110(a)(2)(B) requires SIPs to include provisions to provide for establishment and operation of ambient air quality monitors, collecting and analyzing ambient air quality data, and making these data available to EPA upon request.

Program for enforcement of control measures: Section 110(a)(2)(C) requires States to include a program providing for enforcement of all SIP measures and the regulation of construction of new or modified stationary sources to meet prevention of significant deterioration (PSD) and nonattainment NSR requirements.

Interstate transport: Section 110(a)(2)(D) requires SIPs to include provisions prohibiting any source or other type of emissions activity in one State from contributing significantly to nonattainment, or interfering with maintenance, of the NAAQs in another State, or from interfering with measures required to prevent significant deterioration of air quality or to protect visibility in another State. EPA has already issued CAIR to assist States in developing SIPs to meet this requirement for purposes of the 8-hour Ozone and $PM_{2.5}$ NAAQS, and has issued separate guidance to all States on how to comply with each prong of this statutory provision.

Adequate resources: Section 110(a)(2)(E) requires States to provide for adequate personnel, funding, and legal authority under State law to carry out its SIP, and related issues.

Stationary source monitoring system: Section 110(a)(2)(F) requires States to establish a system to monitor emissions from stationary sources and to submit

periodic emissions reports.

Emergency power: Section 110(a)(2)(G) requires States to provide for authority to address activities causing imminent and substantial endangerment to public health, including contingency plans to implement the emergency episode provisions in their SIPs.

Future SIP revisions: Section 110(a)(2)(H) requires States to have the authority to revise their SIPs in response to changes in the NAAQS, availability of improved methods for attaining the NAAQS, or in response to an EPA finding that the SIP is substantially inadequate.

Consultation with government officials: Section 110(a)(2)(J) requires States to provide a process for consultation with local governments and Federal Land Managers carrying out NAAQS implementation requirements pursuant to section 121 relating to consultation.

Public notification: Section 110(a)(2)(J) further requires States to notify the public if NAAQS are exceeded in an area and to enhance public awareness of measures that can be taken to prevent exceedances.

PSD and visibility protection: Section 110(a)(2)(J) also requires States to meet applicable requirements of part C related to prevention of significant deterioration and visibility protection.

Air quality modeling/data: Section 110(a)(2)(K) requires that SIPs provide for performing air quality modeling for predicting effects on air quality of emissions from any NAAQS pollutant and submission of such data to EPA upon request.

Permitting fees: Section 110(a)(2)(L) requires SIPs to require each major stationary source to pay permitting fees to cover the cost of reviewing, approving, implementing and enforcing a permit.

Consultation/participation by affected local entities: Section 110(a)(2)(M) requires States to provide for consultation and participation in SIP development by local political subdivisions affected by the SIP.

Appendix B

U.S. EPA

Federal Registers

Federal Register

Friday
July 18, 1997

Part II

Environmental Protection Agency

40 CFR Part 50

National Ambient Air Quality Standards for Particulate Matter; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 50

[AD–FRL–5725–2]

RIN 2060–AE66

National Ambient Air Quality Standards for Particulate Matter

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This document describes EPA's decision to revise the national ambient air quality standards (NAAQS) for particulate matter (PM) based on its review of the available scientific evidence linking exposures to ambient PM to adverse health and welfare effects at levels allowed by the current PM standards. The current primary PM standards are revised in several respects: Two new $PM_{2.5}$ standards are added, set at 15 μg/m^3, based on the 3-year average of annual arithmetic mean $PM_{2.5}$ concentrations from single or multiple community-oriented monitors, and 65 μg/m^3, based on the 3-year average of the 98th percentile of 24-hour $PM_{2.5}$ concentrations at each population-oriented monitor within an area; and the current 24-hour PM_{10} standard is revised to be based on the 99th percentile of 24-hour PM_{10} concentrations at each monitor within an area. The new suite of primary standards will provide increased protection against a wide range of PM-related health effects, including premature mortality and increased hospital admissions and emergency room visits, primarily in the elderly and individuals with cardiopulmonary disease; increased respiratory symptoms and disease, in children and individuals with cardiopulmonary disease such as asthma; decreased lung function, particularly in children and individuals with asthma; and alterations in lung tissue and structure and in respiratory tract defense mechanisms. The current secondary standards are revised by making them identical in all respects to the new suite of primary standards. The new secondary standards, in conjunction with a regional haze program, will provide appropriate protection against PM-related public welfare effects including soiling, material damage, and visibility impairment. In conjunction with the new $PM_{2.5}$ standards, a new reference method has been specified for monitoring PM as $PM_{2.5}$.

EFFECTIVE DATE: This action is effective September 16, 1997.

ADDRESSES: A docket containing information relating to the EPA's review of the PM primary and secondary standards (Docket No. A–95–54) is available for public inspection in the Central Docket Section of the U.S. Environmental Protection Agency, South Conference Center, Rm. 4, 401 M St., SW., Washington, DC. This docket incorporates the docket established for the air quality Criteria Document (Docket No. ECAO–CD–92–0671). The docket may be inspected between 8 a.m. and 3 p.m., Monday through Friday, except legal holidays, and a reasonable fee may be charged for copying. The information in the docket constitutes the complete basis for the decision announced in this document. For the availability of related information, see ''SUPPLEMENTARY INFORMATION.''

FOR FURTHER INFORMATION CONTACT: John H. Haines, MD–15, Air Quality Strategies and Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone: (919) 541–5533; e-mail: haines.john@epamail.epa.gov.

SUPPLEMENTARY INFORMATION:

Related Final Rules on PM Monitoring

In a separate document published elsewhere in this issue of the **Federal Register**, EPA is amending its ambient air quality surveillance requirements (40 CFR part 58) and its ambient air monitoring reference and equivalent methods (40 CFR part 53) for PM.

Availability of Related Information

Certain documents are available from the U.S. Department of Commerce, National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161. Available documents include:

(1) Air Quality Criteria for Particulate Matter (Criteria Document) (three volumes, EPA/600/P–95–001aF thru EPA/600/P–95–001cF, April 1996, NTIS #PB–96–168224, $234.00 paper copy).

(2) Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information (Staff Paper) (EPA–452/R–96–013, July 1996, NTIS #PB–97–115406, $47.00 paper copy and $19.50 microfiche). (Add a $3.00 handling charge per order.)

A limited number of copies of other documents generated in connection with this standard review, such as technical support documents pertaining to air quality, monitoring, and health risk assessment, can be obtained from: Environmental Protection Agency Library (MD–35), Research Triangle Park, NC 27711, telephone (919) 541–2777. These and other related documents are also available for inspection and copying in the EPA docket at the address under ''ADDRESSES,'' at the beginning of this document.

Electronic Availability

The Staff Paper and human health risk assessment support documents are available on the Agency's Office of Air Quality Planning and Standards' (OAQPS) Technology Transfer Network (TTN) Bulletin Board System (BBS) in the Clean Air Act Amendments area, under Title I, Policy/Guidance Documents. To access the bulletin board, a modem and communications software are necessary. To dial up, set your communications software to 8 data bits, no parity and one stop bit. Dial (919) 541–5742 and follow the on-screen instructions to register for access. After registering, proceed to choice ''<T> Gateway to TTN Technical Areas'', then choose ''<E> CAAA BBS''. From the main menu, choose ''<1> Title I: Attain/Maint of NAAQS'', then ''<P> Policy Guidance Documents.'' To access these documents through the World Wide Web, click on ''TTN BBSWeb'', then proceed to the Gateway to TTN Technical areas, as above. If assistance is needed in accessing the system, call the help desk at (919) 541–5384 in Research Triangle Park, NC.

Implementation Strategy For Revised Air Quality Standards

On Wednesday, July 16, 1997, President Clinton signed a memorandum to the Administrator specifying his goals for the implementation of the O_3 and PM standards. Attached to the President's memorandum is a strategy prepared by an interagency Administration group outlining the next steps that would be necessary for implementing these standards. The EPA will prepare guidance and proposed rules consistent with the President's memorandum. Copies of the Presidential document are available in paper copy by contacting the U.S. Environmental Protection Agency Library at the address under ''Availability of Related Information'' and in electronic form as discussed above in ''Electronic Availability.''

The following topics are discussed in this preamble:

I. Background

A. Legislative Requirements

Two sections of the Clean Air Act (Act) govern the establishment, review, and revision of NAAQS. Section 108 of the Act (42 U.S.C. 7408) directs the Administrator to identify certain pollutants which ''may reasonably be anticipated to endanger public health and welfare'' and to issue air quality criteria for them. These air quality criteria are to ''accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of [a] pollutant in the ambient air * * *.''

Section 109 of the Act (42 U.S.C. 7409) directs the Administrator to propose and promulgate ''primary'' and ''secondary'' NAAQS for pollutants identified under section 108 of the Act. Section 109(b)(1) of the Act defines a primary standard as one ''the attainment and maintenance of which in the judgment of the Administrator, based on [the] criteria and allowing an adequate margin of safety, are requisite to protect the public health.'' The margin of safety requirement was intended to address uncertainties associated with inconclusive scientific and technical information available at the time of standard setting, as well as to provide a reasonable degree of protection against hazards that research has not yet identified. Both kinds of uncertainties are components of the risk associated with pollution at levels below those at which human health effects can be said to occur with reasonable scientific certainty. Thus, by selecting primary standards that provide an adequate margin of safety, the Administrator is seeking not only to prevent pollution levels that have been demonstrated to be harmful but also to prevent lower pollutant levels that she finds may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. The Act does not require the Administrator to establish a primary NAAQS at a zero-risk level, but rather at a level that reduces risk sufficiently so as to protect public health with an adequate margin of safety. The selection of any particular approach to providing an adequate margin of safety is a policy choice left specifically to the Administrator's judgment. *Lead Industries Ass'n* v. *EPA*, 647 F.2d 1130, 1161–1162 (D.C. Cir.1980).

A secondary standard, as defined in section 109 (b)(2) of the Act, must ''specify a level of air quality the attainment and maintenance of which in the judgment of the Administrator, based on [the] criteria, [are] requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of [the] pollutant in the ambient air.'' Welfare effects as defined in section 302(h) of the Act (42 U.S.C. 7602(h)) include, but are not limited to, ''effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being.''

Section 109(d)(1) of the Act requires periodic review and, if appropriate, revision of existing air quality criteria and NAAQS. Section 109(d)(2) of the Act requires appointment of an independent scientific review committee to review criteria and standards and recommend new standards or revisions of existing criteria and standards, as appropriate. The committee established under section 109(d)(2) of the Act is known as the Clean Air Scientific Advisory Committee (CASAC), a standing committee of EPA's Science Advisory Board.

B. Related Control Requirements

States are primarily responsible for ensuring attainment and maintenance of ambient air quality standards once EPA has established them. Under section 110 of the Act (42 U.S.C. 7410) and related provisions, States are to submit, for EPA approval, State implementation plans (SIP's) that provide for the attainment and maintenance of such standards through control programs directed to sources of the pollutants involved. The States, in conjunction with EPA, also administer the prevention of significant deterioration program (42 U.S.C. 7470–7479) for these pollutants. In addition, Federal programs provide for nationwide reductions in emissions of these and other air pollutants through the Federal Motor Vehicle Control Program under Title II of the Act (42 U.S.C. 7521–7574), which involves controls for automobile, truck, bus, motorcycle, nonroad engine, and aircraft emissions; the new source performance standards under section 111 of the Act (42 U.S.C. 7411); and the national emission standards for hazardous air pollutants under section 112 of the Act (42 U.S.C. 7412).

C. Review of Air Quality Criteria and Standards for PM

Particulate matter is the generic term for a broad class of chemically and physically diverse substances that exist as discrete particles (liquid droplets or solids) over a wide range of sizes. Particles originate from a variety of anthropogenic stationary and mobile sources as well as from natural sources. Particles may be emitted directly or formed in the atmosphere by transformations of gaseous emissions such as sulfur oxides (SO_x), nitrogen oxides (NO_x), and volatile organic compounds (VOC). The chemical and physical properties of PM vary greatly with time, region, meteorology, and source category, thus complicating the assessment of health and welfare effects.

The last review of PM air quality criteria and standards was completed in July 1987 with notice of a final decision to revise the existing standards published in the **Federal Register** (52 FR 24854, July 1, 1987). In that decision, EPA changed the indicator for PM from total suspended particles (TSP) to

PM_{10}.[1] Identical primary and secondary PM_{10} standards were set for two averaging times: 50 μg/m³, expected annual arithmetic mean, averaged over 3 years, and 150 μg/m³, 24-hour average, with no more than one expected exceedance per year.[2]

The EPA initiated this current review of the air quality criteria and standards for PM in April 1994 by announcing its intention to develop a revised Air Quality Criteria Document for Particulate Matter (henceforth, the ''Criteria Document''). Thereafter, the EPA presented its plans for review of the criteria and standards for PM under a highly accelerated, court-ordered schedule[3] at a public meeting of the CASAC in December 1994. Several workshops were held by EPA's National Center for Environmental Assessment (NCEA) to discuss important new health effects information in November 1994 and January 1995. External review drafts of the Criteria Document were made available for public comment and were reviewed by CASAC at public meetings held in August and December 1995 and February 1996. The CASAC came to closure in its review of the Criteria Document, advising the Administrator in a March 15, 1996 closure letter (Wolff, 1996a) that ''although our understanding of the health effects of PM is far from complete, a revised Criteria Document which incorporates the Panel's latest comments will provide an adequate review of the available scientific data and relevant studies of PM.'' CASAC and public comments from these meetings, and from subsequent written comments and the closure letter, were incorporated as appropriate in the final Criteria Document (U.S. EPA, 1996a).

External review drafts of a Staff Paper prepared by the Office of Air Quality Planning and Standards (OAQPS), Review of the National Ambient Air Quality Standards for Particulate Matter: Assessment of Scientific and Technical Information (henceforth, the ''Staff Paper''), were made available for public comment and were reviewed by CASAC at public meetings in December 1995 and May 1996.[4] The CASAC came to closure in its review of the Staff Paper, advising the Administrator in a June 13, 1996 closure letter (Wolff, 1996b) that ''the Staff Paper, when revised, will provide an adequate summary of our present understanding of the scientific basis for making regulatory decisions concerning PM standards.'' CASAC and public comments from these meetings, subsequent written comments, and the CASAC closure letter were incorporated as appropriate in the final Staff Paper (U.S. EPA, 1996b).

On November 27, 1996, EPA announced its proposed decision to revise the NAAQS for PM (61 FR 65638, December 13, 1996) (hereafter ''proposal'') as well as its proposed decision to revise the NAAQS for ozone (O_3)(61 FR 65716, December 13, 1996). In the proposal, EPA identified proposed revisions, based on the air quality criteria for PM, and solicited public comments on alternative primary standards and on the proposed forms of the standards.

To ensure the broadest possible public input on the PM and O_3 proposals, EPA took extensive and unprecedented steps to facilitate the public comment process beyond the normal process of providing an opportunity to request a hearing and receiving written comments submitted to the rulemaking docket. The EPA established a national toll-free telephone hotline to facilitate public comments on the proposed revisions to the PM and O_3 NAAQS, and on related notices dealing with the implementation of revised PM and O_3 standards, as well as a system for the public to submit comments on the proposals electronically via the Internet. Over 14,000 calls and over 4,000 electronic mail messages were received through these channels. The public could also access key supporting documents (including the Criteria Document, Staff Paper, related technical documents and fact sheets) via the Internet.

The EPA also held several public hearings and meetings across the country to provide direct opportunities for public comment on the proposed revisions to the PM and O_3 NAAQS and to disseminate information to the public about the proposed standard revisions. On January 14 and 15, 1997, EPA held concurrent, 2-day public hearings in Boston, MA, Chicago, IL, and Salt Lake City, UT. A fourth public hearing, which focused primarily on PM monitoring issues, was held in Durham, NC on January 14, 1997. Over 400 citizens and organizations testified during these public hearings. EPA also held two national satellite telecasts to answer questions on the standards and participated in meetings sponsored by the Air and Waste Management Association on the proposed revisions to the standards at more than 10 locations across the country. Beyond that, several EPA regional offices held public meetings and workshops and participated in hearings that States and cities held around the country.

As a result of this intensive effort to solicit public input, over 50,000 written and oral comments were received on the proposed revisions to the PM NAAQS by the close of the public comment period on March 12, 1997. Major issues raised in the comments are discussed throughout the preamble of this final decision. A comprehensive summary of all significant comments, along with EPA's response to such comments (hereafter ''Response to Comments''), can be found in the docket for this rulemaking (Docket No. A–95–54).

The principal focus of this current review of the air quality criteria and standards for PM is on recent epidemiological evidence reporting associations between ambient concentrations of PM and a range of serious health effects. Particular attention has been given to several size-specific classes of particles, including PM_{10} and the principal fractions of PM_{10}, referred to as the fine ($PM_{2.5}$)[5] and coarse ($PM_{10-2.5}$)[6] fractions. As discussed in the Criteria Document, fine and coarse fraction particles can be differentiated by their sources and formation processes and their chemical and physical properties, including behavior in the atmosphere. Detailed discussions of atmospheric formation, ambient concentrations, and health and welfare effects of PM, as well as quantitative estimates of human health risks associated with exposure to PM, can be found in the Criteria Document and in the Staff Paper.

[1] PM_{10} refers to particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers. Technical details further specifying the measurement of PM_{10} are contained in 40 CFR part 50, Appendices J and M.

[2] A more complete history of the PM NAAQS is presented in section II.B of the OAQPS Staff Paper, Review of National Ambient Air Quality Standards for Particulate Matter: Assessment of Scientific and Technical Information (U.S. EPA, 1996b).

[3] A court order entered in *American Lung Association* v. *Browner*, CIV–93–643–TUC–ACM (D. Ariz.,October 6, 1994), as subsequently modified, requires publication of EPA's final decision on the review of the PM NAAQS by July 19, 1997.

[4] The Staff Paper evaluates policy implications of the key studies and scientific information in the Criteria Document, identifies critical elements that EPA staff believes should be considered, and presents staff conclusions and recommendations of suggested options for the Administrator's consideration.

[5] $PM_{2.5}$ refers to particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, as further specified in 40 CFR part 50, Appendix L in this document.

[6] $PM_{10-2.5}$ refers to those particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers but greater than 2.5 micrometers. In other words, it refers to the inhalable particles that remain if fine ($PM_{2.5}$) particles are removed from a sample of PM_{10} particles.

D. Summary of Proposed Revisions to the PM Standards

For reasons discussed in the proposal, the Administrator proposed to revise the current primary standards for PM (as indicated by PM_{10}), by adding two new primary $PM_{2.5}$ standards set at 15 μg/m^3, annual mean, and 50 μg/m^3, 24-hour average. The proposed annual $PM_{2.5}$ standard would be based on the 3-year average of the annual arithmetic mean $PM_{2.5}$ concentrations, spatially averaged across an area. The proposed 24-hour $PM_{2.5}$ standard would be based on the 3-year average of the 98th percentile of 24-hour $PM_{2.5}$ concentrations at each population-oriented monitor within an area. The proposal solicited comment on two alternative approaches for selecting the levels of $PM_{2.5}$ standards. The Administrator also proposed to revise the current 24-hour primary PM_{10} standard of 150 μg/m^3 by replacing the 1-expected-exceedance form with a 98th percentile form, averaged over 3 years at each monitor within an area, solicited comment on an alternative proposal to revoke the 24-hour PM_{10} standard, and proposed to retain the current annual primary PM_{10} standard of 50 μg/m^3. The proposal also solicited comment on proposed revisions to 40 CFR part 50, Appendix K to establish new data handling conventions for calculating 98th percentile values and spatial averages, revisions to 40 CFR part 50, Appendix J to modify the reference method for monitoring PM as PM_{10}, and a proposed new reference method for monitoring PM as $PM_{2.5}$ (40 CFR part 50, Appendix L).

With regard to the secondary standards, the Administrator proposed to revise the current secondary standards by making them identical to the suite of proposed primary standards, in conjunction with the establishment of a regional haze program under section 169A of the Act.

II. Rationale for the Primary Standards

A. Introduction

1. *Overview.* This document presents the Administrator's final decisions regarding the need to revise the current primary ambient air quality standards for PM, and, more specifically, regarding the establishment of new annual and 24-hour $PM_{2.5}$ primary standards and revisions to the form of the current 24-hour PM_{10} primary NAAQS. These decisions are based on a thorough review, in the Criteria Document, of the latest scientific information on known and potential human health effects associated with exposure to PM at levels typically found in the ambient air. These decisions also take into account:

(1) Staff Paper assessments of the most policy-relevant information in the Criteria Document, upon which staff recommendations for new and revised primary standards are based.

(2) CASAC advice and recommendations, as reflected in discussions of drafts of the Criteria Document and Staff Paper at public meetings, in separate written comments, and in the CASAC's closure letters to the Administrator.

(3) Public comments received during the development of these documents, either in connection with CASAC meetings or separately.

(4) Extensive public comments received on the proposed decisions regarding the primary PM standards.

After taking this information and comments into account, and for the reasons discussed below in this unit, the Administrator concludes that revisions to the current primary standards to provide increased public health protection against a variety of health risks are appropriate. More specifically, the Administrator has determined that it is appropriate to establish new annual and 24-hour $PM_{2.5}$ standards, to revise the current 24-hour PM_{10} standard, and to retain the current annual PM_{10} standard. As discussed more fully below in this unit, the rationale for the final decisions regarding the PM primary NAAQS includes consideration of:

(1) Health effects information, and alternative views on the appropriate interpretation and use of the information, as the basis for judgments about the risks to public health presented by population exposures to ambient PM.

(2) Insights gained from a quantitative risk assessment conducted to provide a broader perspective for judgments about protecting public health from the risks associated with PM exposures.

(3) Specific conclusions regarding the need for revisions to the current standards and the elements of PM standards (i.e., indicator, averaging time, form, and level) that, taken together, would be appropriate to protect public health with an adequate margin of safety.

As with virtually any policy-relevant scientific research, there is uncertainty in the characterization of health effects attributable to exposure to ambient PM. As discussed in the proposal, however, there is now a greatly expanded body of health effects information as compared with that available during the last review of the PM standards. Moreover, the recent evidence on PM-related health effects has undergone an unusually high degree of scrutiny and reanalysis over the past several years, beginning with a series of workshops held early in the review process to discuss important new information. A number of opportunities were provided for public comment on successive drafts of the Criteria Document and Staff Paper, as well as for intensive peer review of these documents by CASAC at several public meetings attended by many knowledgeable individuals and representatives of interested organizations. In addition, there have been a number of important scientific conferences, symposia, and colloquia on PM issues, sponsored by the EPA and others, in the U.S. and abroad, during this period. While significant uncertainties exist, the review of the health effects information has been thorough and deliberate. In the judgment of the Administrator, this intensive evaluation of the scientific evidence has provided an adequate basis for regulatory decision making at this time, as well as for the comprehensive research needs document recently developed by EPA, and reviewed by CASAC and others, for improving our future understanding of the relationships between ambient PM exposures and health effects.

The health effects information and human risk assessment were summarized in the proposal and are only briefly outlined below in this unit. Subsequent units provide a more complete discussion of the Administrator's rationale, in light of key issues raised in public comments, for concluding that it is appropriate to revise the current primary standards (Unit II.B. of this preamble) and to revise the specific elements of the standards including indicator (Unit II.C. of this preamble); averaging time, form, and level of new $PM_{2.5}$ standards (Units II.D., II.E., and II.F. of this preamble); and averaging time, form, and level of revised PM_{10} standards (Unit II.G. of this preamble).

2. *Summary of the health effects evidence.* In brief, since the last review of the PM criteria and standards, the most significant new evidence on the health effects of PM is the greatly expanded body of community epidemiological studies. The Criteria Document stated that these recent studies provide ''evidence that serious health effects (mortality, exacerbation of chronic disease, increased hospital admissions, etc.) are associated with exposures to ambient levels of PM found in contemporary U.S. urban airsheds even at concentrations below current U.S. PM standard'' (U.S. EPA, 1996a; p. 13-1). Although a variety of

responses to constituents of ambient PM have been hypothesized to contribute to the reported health effects, the relevant toxicological and controlled human studies published to date have not identified any accepted mechanism(s) that would explain how such relatively low concentrations of ambient PM might cause the health effects reported in the epidemiological literature.

Unit II.A. of the proposal further outlines key information contained in the Criteria Document, Chapters 10-13, and the Staff Paper, Chapter V, on the known and potential health effects associated with airborne PM, alone and in combination with other pollutants that are routinely present in the ambient air. The information highlighted there summarizes:

(1) The nature of the effects that have been reported to be associated with ambient PM, which include premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions and emergency room visits, school absences, work loss days, and restricted activity days), changes in lung function and increased respiratory symptoms, changes to lung tissues and structure, and altered respiratory defense mechanisms.

(2) Sensitive subpopulations that appear to be at greater risk to such effects, specifically individuals with respiratory disease and cardiovascular disease and the elderly (premature mortality and hospitalization), children (increased respiratory symptoms and decreased lung function), and asthmatic children and adults (aggravation of symptoms).

(3) An integrated evaluation of the health effects evidence, with an emphasis on the key issues raised in assessing community epidemiological studies, including alternative interpretations of the evidence, both for individual studies and for the evidence as a whole.

(4) The PM fractions of greatest concern to health.

The summary in the proposal will not be repeated here. EPA emphasizes that the final decisions on these standards take into account the more comprehensive and detailed discussions of the scientific information on these issues contained in the Criteria Document and Staff Paper, which were reviewed by the CASAC and the public.

3. *Key insights from the risk assessment.* The Staff Paper presents the results of a quantitative assessment of health risks for two example cities, including risk estimates for several categories of health effects associated with: existing PM air quality levels, projected PM air quality levels that would occur upon attainment of the current PM_{10} standards, and projected PM air quality levels that would occur upon attainment of alternative $PM_{2.5}$ standards. The risk assessment is intended as an aid to the Administrator in judging which alternative PM NAAQS would reduce risks sufficiently to protect public health with an adequate margin of safety, recognizing that such standards will not be risk-free. The risk assessment is described more fully in the Staff Paper and summarized in the proposal. Related technical reports and updates[7] have been placed in the docket (Abt Associates, 1996a,b; 1997a,b).

EPA emphasizes that it places greater weight on the overall conclusions derived from the studies—that PM air pollution is likely causing or contributing to significant adverse effects at levels below those permitted by the current standards—than on the specific concentration-response functions and quantitative risk estimates derived from them. These quantitative risk estimates include significant uncertainty and, therefore, should not be viewed as demonstrated health impacts. EPA believes, however, that they do represent reasonable estimates as to the possible extent of risk for these effects given the available information. Keeping in mind the important uncertainties inherent in any such analyses, the key insights from the risk assessment that are most pertinent to the current decision include:

(1) Fairly wide ranges of estimates of the incidence of PM-related mortality and morbidity effects and risk reductions associated with attainment of alternative standards were calculated for the two locations analyzed when the effects of key uncertainties and alternative assumptions were considered. Significantly, the combined analysis for these two cities alone found that the risk remaining after attaining the current PM_{10} standards was on the order of hundreds of premature deaths each year, hundreds to thousands of respiratory-related hospital admissions, and tens of thousands of additional respiratory related symptoms in children.

(2) Based on the results from the sensitivity analyses of key uncertainties and the integrated uncertainty analyses, the single most important factor influencing the uncertainty associated with the risk estimates is whether or not a threshold concentration exists below which PM-associated health risks are not likely to occur.

(3) Over the course of a year, the few peak 24-hour $PM_{2.5}$ concentrations appear to contribute a relatively small amount to the total health risk posed by the entire air quality distribution as compared to the aggregated risks associated with the low to mid-range concentrations.

(4) There is greater uncertainty about both the existence and the magnitude of estimated excess mortality and other effects associated with PM exposures as one considers increasingly lower concentrations approaching background levels.

B. Need for Revision of the Current Primary PM Standards

1. *Introduction.* The overarching issue in the present review of the primary NAAQS is whether, in view of the advances in scientific knowledge reflected in the Criteria Document and Staff Paper, the existing PM standards should be revised and, if so, what revised or new standards would be appropriate. The concluding section of the integrative synthesis of health effects information in the Criteria Document, which CASAC characterized as EPA's ''best ever example of a true integrative summary of the state of knowledge about the health effects of airborne PM,'' (Wolff, 1996b) provides the following summary of the science with respect to this issue:

> The evidence for PM-related effects from epidemiological studies is fairly strong, with most studies showing increases in mortality, hospital admissions, respiratory symptoms, and pulmonary function decrements associated with several PM indices. These epidemiological findings cannot be wholly attributed to inappropriate or incorrect statistical methods, misspecification of concentration-effect models, biases in study design or implementation, measurement errors in health endpoint, pollution exposure, weather, or other variables, nor confounding of PM effects with effects of other factors. While the results of the epidemiological studies should be interpreted cautiously, they nonetheless provide ample reason to be concerned that there are detectable health effects attributable

[7] The risk assessment results that appear in the Staff Paper and are summarized in the proposal have been updated to include analyses of the particular forms of standard alternatives contained in the proposal and to correct estimates for one effects category (mortality from long-term exposure) to reflect the actual statistics used in the study upon which they were based (Pope et al., 1995). The corrections, which cumulatively reduce estimates of mortality associated with long-term exposures by 20 to 35%, have no effect on risk estimates for mortality associated with short-term exposures or the estimates for any other effects. Because the key sensitivity analyses that provide additional insights regarding thresholds, copollutants, averaging time and related issues involved the short-term exposure studies, none of these results are affected by changes to the long-term exposure risk estimates.

to PM at levels below the current NAAQS. [U.S. EPA, 1996a, p. 13-92]

Given the nature of the health effects in question, this finding, which is based on a large number of studies that used PM_{10} measurements, as well as studies using other indicators of PM, clearly indicates that revision of the current PM NAAQS is appropriate. Quite apart from the issue of whether PM_{10} should be the sole indicator for the PM NAAQS, the extensive PM epidemiological data base provides evidence of serious health effects (e.g., mortality, exacerbation of chronic disease, increased hospital admissions) in sensitive populations (e.g., the elderly, individuals with cardiopulmonary disease), as well as significant adverse health effects (e.g., increased respiratory symptoms, school absences, and lung function decrements) in children. Moreover, these effects associations are observed in areas or at times when the levels of the current PM_{10} standards are met. Although the increase in relative risk is small for the most serious outcomes, EPA believes it is significant from an overall public health perspective, because of the large number of individuals in sensitive populations that are exposed to ambient PM, as well as the significance of the health effects involved (U.S. EPA, 1996a, p. 1-21). The results of the two-city PM risk assessment reinforce these conclusions regarding the significance of the public health risk—even under a scenario in which the current PM_{10} standards are attained.

While the lack of demonstrated mechanisms that explain the extensive body of epidemiological findings is an important caution, which presents difficulties in providing an integrated assessment of PM health effects research, a number of potential mechanisms have been hypothesized in the recent literature (U.S. EPA, 1996b; p. V-5 to V-8; appendix D). Moreover, qualitative information from laboratory studies of the effects of particle components at high concentrations and dosimetry considerations suggest that the kinds of effects observed in community studies (e.g., respiratory- and cardiovascular-related responses) are at least plausibly related to inhalation of PM.[8] Indeed, as discussed in the Criteria Document and section V.E of the Staff Paper, the consistency of the results of the epidemiological studies from a large number of different locations and the coherent nature of the observed effects[9] are suggestive of a likely causal role of ambient PM in contributing to the reported effects.

2. *Comments on scientific basis for revision.* A majority of the public comments received on the proposal agreed that, based on the available scientific information, the current PM_{10} standards are not of themselves sufficient to protect public health and it would be appropriate to revise them. Included in those calling for revisions to the current standards are many public health professionals, including numerous medical doctors and academic researchers. For example, a group of 27 members of the scientific and medical community recognized as having substantial expertise in conducting research on the health effects of air pollution stated:

> Health studies conducted in the U.S. and around the world have demonstrated that levels of particulate and ozone air pollution below the current U.S. National Air Quality Standards exacerbate serious respiratory disease and contribute to early death. A large body of scientific and medical evidence clearly indicates that the current NAAQS are not sufficiently protective of public health. [Thurston, 1997]

Similar conclusions were reached in a letter signed by more than 1,000 scientists, clinicians, researchers, and other health care professionals (Dickey, 1997). The cosigners to this letter argued that tens of thousands of hospital visits and premature deaths could be prevented with the proposed air quality standard revisions. In fact, these commenters argued that even stronger standards than those proposed by EPA are needed to protect the health of the most vulnerable residents of our communities.

A number of State and local government authorities also submitted comments in support of adopting new air quality standards for fine particulate matter. The commenters concurred with conclusions reached through the EPA's peer review process that the PM standards should be revised to protect public health. A number of these commenters suggested that the standards proposed by EPA should be even stronger, while several other State agencies recommended that EPA adopt $PM_{2.5}$ standards, but at less stringent levels. A number of the comments from states supporting even stronger standards acknowledged the lack of demonstrated mechanism(s) and other uncertainties but stressed the strength of the other evidence in urging EPA to set protective standards.

Many comments were also received from representatives of environmental or community health organizations that supported the adoption of air quality standards for $PM_{2.5}$. These commenters agreed with EPA's finding that a large body of compelling evidence demonstrates that exposure to particulate matter pollution, in general, is associated with premature death, aggravation of heart and lung diseases, increased respiratory illness and reduced lung function. They agreed with EPA that these studies present a consistent and coherent relationship between exposure to PM and both mortality and various measures of morbidity. However, the majority of these commenters argued that EPA's proposed standards for $PM_{2.5}$ were inadequate and recommended adoption of more stringent levels of the 24-hour and/or annual air quality standards for $PM_{2.5}$. Many of these commenters also urged EPA to revise the NAAQS for PM_{10} to be more protective of public health. These commenters based their recommendations on the findings of the studies that were reviewed in the preparation of the Criteria Document and Staff Paper. One commenter used results from five of these studies as the basis for recommending $PM_{2.5}$ standards of 10 $\mu g/m^3$ (annual) and 18 $\mu g/m^3$ (24-hour) (Dockery et al., 1993; Pope et al., 1995; Schwartz et al., 1996; Schwartz et al., 1994; Thurston et al., 1994). The commenters agreed with EPA on the significance of these studies' results and the need to revise the PM standards, while differing with EPA's interpretation of the findings for purposes of developing the proposed PM standards.

Several commenters made reference to the conclusions of a number of international scientific panels regarding the health effects of exposure to airborne particulate matter—the British Expert Panel on Air Quality Standards, the British Committee on the Medical Effects of Air Pollutants, the World Health Organization, the Canadian Ministry of Environment, Lands and Parks, and the Health Council of the Netherlands -- and argued that all these panels found that PM concentrations equivalent to the current U.S. standards for PM_{10} are not protective of human health and made recommendations for greater protection. One commenter noted that the findings of the British Health Panel have resulted in a British

[8] As discussed more fully below in this unit, epidemiological studies alone cannot be used to demonstrate mechanisms of action, but they can provide evidence useful in making inferences with regard to causal relationships (U.S. EPA, 1996b, p. V-9).

[9] As noted in the proposal, the kinds of effects observed in the epidemiological studies are logically related. For example, the association of PM with mortality is mainly linked to respiratory and cardiovascular causes, which is coherent with observed PM associations with respiratory and cardiovascular hospital admissions and respiratory symptoms. Further, similar categories of effects are seen in long- and short-term exposure studies.

proposal to adopt a 24-hour PM_{10} standard of 50 $\mu g/m^3$, which is one-third the level of the current U.S. NAAQS.

In these comments, some toxicological studies were cited as providing evidence for toxicity of particulate pollution. These commenters disagreed with arguments that PM standards cannot be adopted due to a lack of a sufficient understanding of the biological mechanism of injury. The commenters argued that there is sufficient evidence that particulate pollution is associated with adverse health effects to make it inappropriate to delay the establishment of standards while further studies are undertaken. This group of commenters was also critical of arguments against the establishment of additional PM standards based on the possibility of confounding by other pollutants, and urged that more attention be paid instead to the possible additive or synergistic effects of multiple pollutant exposures.

In general, the EPA agrees with these commenters' arguments regarding the need to revise the PM standards. The scientific studies cited by these commenters were the same studies used in the development of the Criteria Document and the Staff Paper, and the EPA agrees that there is a sufficient body of evidence that the current NAAQS for PM are not adequately protective of the public health. For reasons detailed in Unit II.F. of this preamble and in the Response to Comments, EPA disagrees with aspects of these commenters' views on the level of protection that is appropriate and supported by the available scientific information.

Another body of commenters, including almost all commenters representing businesses and industry associations, many local governmental groups and private citizens, and some States opposed revising the standards. Many of these commenters argued that the available scientific evidence does not provide an adequate basis for revising the current standards. The central arguments made by these commenters can be divided into two categories: (1) General comments on the appropriateness of relying on the epidemiological evidence for making regulatory decisions, and (2) more specific comments challenging EPA's appraisal of the consistency and coherence of the available information, EPA's conclusions regarding causality, and the use of these studies for risk assessment and decisions on whether to revise the standards. While EPA has included comprehensive responses to these comments in the Response to Comments, certain key points are summarized below in this unit.

a. *General comments on the use of epidemiological studies.* The first category of comments was largely derived from ad hoc panels of occupational and other epidemiological experts, consulting groups, and individual consultants. Most of these individuals and groups commented on the use of epidemiology in reaching scientific and policy conclusions primarily from an occupational or hazard assessment perspective, in contrast to the perspective of the review of ambient PM criteria and standards, where the use of community air pollution epidemiological studies are central. Citing accepted criteria used in evaluating epidemiological studies to assess the likelihood of causality (most notably those of Sir Austin Bradford Hill, 1965), these commenters argued that in the absence of a demonstrated biological mechanism, the relative risks of effects in the PM epidemiological studies are too low (less than values variously cited as 1.5 to 2.0) to reach any conclusions regarding causality or to form the basis for regulations. In general, the commenters applied these criteria to a subset of studies evaluated in the Criteria Document, including as few as two long-term exposure studies (EOP Group) (API, 1997), a group of 9 selected studies (Greenland panel) (API, 1997), those studies cited in the proposal (AIHC, 1997), or as many as 23 selected short-term exposure studies examined in a recently published review paper (Gamble and Lewis, 1996).

Based on a careful review of these comments, EPA notes a number of limitations in these commenters' evaluations of the epidemiological studies that they considered, as discussed in detail in the Response to Comments. In summary, EPA notes that these commenters provided scientific advice and conclusions that are in substantial disagreement with the conclusions of the review reflected in the Criteria Document and Staff Paper. EPA stands behind the scientific conclusions reached in these documents regarding the appropriate use of the available community epidemiological studies. These documents were the product of an extended public process that included conducting public workshops involving the leading researchers in the field, drafts of the Criteria Document and Staff Paper providing opportunities for public scrutiny and comment on, and, not least, receiving the advice of an independent panel of air pollution experts, including epidemiologists.

EPA clearly specified the key criteria by which it evaluated the available epidemiological studies in section 12.1.2 of the Criteria Document, with substantial reliance on those specified by Hill (1965). In rejecting results with relative risks less than 1.5 to 2 as meaningful absent demonstrated biological mechanisms, the commenters fail to note that Hill and other expert groups (U.S. DHEW, 1964) have emphasized that no one criterion is definitive by itself, nor is it necessary that all be met in order to support a determination of causality (U.S. EPA, 1996a, p. 12-3).

With respect to biological plausibility, Hill noted that ''this is a feature I am convinced we cannot demand. What is biologically plausible depends upon the biological knowledge of the day'' (Hill, 1965). This statement is clearly pertinent to the toxicological and mechanistic understanding of the effects of PM and associated air pollutants, especially at lower concentrations. It is also important to stress that while the mechanistic evidence published as of the time the Criteria Document closed does not provide quantitative support for the epidemiological results, neither can such limited evidence refute these findings. It is also important to stress that our understanding of biological mechanisms for PM pollution effects is not sufficient to explain the effects observed at much higher concentrations in air pollution episodes, for which causality is generally accepted. Moreover, the toxicological literature has only recently begun to examine animal models (or controlled human studies) that might reflect the sensitive populations in question (the elderly, individuals with chronic respiratory and cardiovascular disease) or that adequately reproduce all of the physico-chemical properties of particles in the ambient atmosphere. In short, the absence of evidence of a particular mechanism is hardly proof that there are no mechanisms that could explain the effects observed so consistently in the epidemiological studies. The absence of biological mechanisms did not deter CASAC from recommending revisions to the PM standards in 1982, 1986, and again in 1996.

While Hill appropriately emphasized the strength of the association as important (e.g., size of the relative risk), he also pointed out that ''We must not be too ready to dismiss a cause-and-effect hypothesis merely on the ground that the observed association appears to be slight. There are many occasions in medicine when this in truth is so'' (Hill, 1965). EPA believes that the effects of air pollution containing PM is such a

case. Unlike the ''textbook'' examples of unlikely significant associations provided by some commenters (e.g., ice cream consumption correlated with heat stroke), the abundant epidemiological literature on combustion particles documents numerous occasions in which single short-term episodes of high air pollution produced unequivocally elevated relative risks. For the week of the well documented 1952 London air pollution episode, for example, the relative risk of mortality for all causes was 2.6, while the relative risk for bronchitis mortality was as high as 9.3 (Ministry of Health, 1954). Hospital admissions also increased by more than a factor of two. British epidemiologists in the 1950s concluded that increased mortality was likely when PM (as mass calibrated British Smoke <4.5 μm in aerodynamic diameter) exceeded 500 $\mu g/m^3$ (Martin and Bradley, 1960). This is only about a factor of 3 higher than that allowed by the current PM standard. Unlike the ''textbook'' and other unlikely statistical associations noted by some commenters, where the only evidence is for low relative risk, clear and convincing links between high-level PM concentrations and mortality and morbidity buttress the findings of similar associations at much lower PM concentrations as suggested in the more recent epidemiological literature.

These commenters also appear to ignore several epidemiological studies conducted at low PM concentrations in U.S. and European cities, including both short- and long-term exposures to PM air pollution, that find statistically significant relative risks of respiratory symptom categories in children in the range of 1.5 to 5 (Schwartz et al., 1994; Pope and Dockery, 1992; Braun-Fahrlander et al., 1992; Dockery et al., 1989; Dockery et al., 1996). Concentrations in these studies extend from moderately above to well below those permitted by the current PM_{10} standards. While, as noted in the proposal, most of the recent epidemiological studies of mortality and hospital admissions report comparatively small relative risks, the findings of relative risks well in excess of the 1.5 to 2 criterion noted by commenters for earlier studies of high PM episodes, as well as the relative risks of 1.5 to 5 reported in more recent studies of less serious, but still important effects categories, lend credibility to EPA's interpretation of the results.

In addition to basing their conclusions primarily on their own assessment of a limited set of studies, this group of commenters reached different conclusions about the consistency of the observed associations because of their assumptions that all model building strategies by all authors are equally valid. Even the most thorough of these treatments (Gamble and Lewis, 1996) shared this flaw, particularly in the discussion of the series of Philadelphia mortality studies and in the discussion of modeling approaches. The authors' treatment of modeling and confounding issues was further limited because they did not include the most recent Philadelphia results (Samet et al., 1996a,b) sponsored by the Health Effects Institute (HEI, 1997). One of the important functions of the Criteria Document is to evaluate the strengths and limitations of various studies. As discussed more fully below in this unit, the Criteria Document found that some of the studies cited by commenters as suggesting a lack of consistency had important limitations. In general, these commenters' analyses suffered by ignoring the much more thorough critical review of these studies and issues contained in the Criteria Document, notably that in section 12.6 on alternative modeling approaches.

EPA also rejects the notion advanced by these commenters that epidemiological studies must use personal exposure monitoring to be considered for regulatory purposes. In particular, commenters ignore the significant strengths of the time-series studies and prospective cohort studies relied on by EPA as compared to cross-sectional epidemiological studies. Time-series studies, such as the daily mortality studies, look at changes in response rate in relation to changes in weather and air pollution over time intervals of a few days. This controls for other factors such as smoking and socioeconomic status, which are little changed during such short intervals. Prospective cohort studies (e.g., Pope et al., 1995; Raizenne et al., 1996), on the other hand, look at changes in health status in a selected cohort of individuals, which allows direct adjustment for smoking status, socioeconomic status, and other subject-specific factors. The commenters also ignore the Criteria Document conclusions on how properly conducted monitoring can provide an adequate index of population exposure to ambient air pollution in such studies that, as detailed below, is more relevant to establishing ambient air quality standards (U.S. EPA 1996a, chapter 7). Although personal monitoring may be practical for some occupational and epidemiological studies, and has been employed in some past studies of air pollution, it is not realistic to require personal monitors in air pollution studies of daily mortality, which require urban scale population data over a period of years. Furthermore, the use of community monitoring-based epidemiological studies as a basis for establishing standards and guidelines has a long history in air pollution, including the British authorities' response to the London episodes and the establishment of the original U.S. NAAQS in 1971. Rejecting the use of the vast array of such studies on this basis alone would also go against the advice of the independent scientific experts on every CASAC panel that has addressed the subject of PM pollution through the years, each of which has recommended general PM standards based primarily on the results of community epidemiological studies (Friedlander, 1982; Lippmann, 1986; Wolff, 1996b). As noted above in this unit, EPA has included a more detailed discussion of its responses to these comments in the Response to Comments.

b. *Specific comments on epidemiologic studies.* The second group of commenters noted above made more specific challenges to EPA's assessment of the epidemiological studies. These comments, although overlapping some of those made by the first group, were generally made by commenters who have taken a more active role in the review of the Criteria Document and Staff Paper. These commenters asserted that the epidemiological evidence on PM is not as consistent and coherent as EPA has claimed, and, in particular, charged that EPA ignored or downplayed a number of studies that the commenters argue contradict the evidence the Agency cited as supporting the consistency and coherence of PM effects. The studies, all of which commenters contend do a better job of addressing one or more key issues, such as confounding pollutants, weather, exposure misclassification, and model specification, than earlier studies, include several that were available during preparation of the Criteria Document, and a number that appeared after the Criteria Document and Staff Paper were completed. Because the status of the later studies differ from that of the earlier ones for purposes of decisions under section 109 of the Act, the two categories are discussed separately below in this unit. Additional responses to comments relating to both sets of studies have been included in the Response to Comments. In addition to the inclusion of specific studies, commenters also raised other issues regarding the limitations of the

epidemiological information and the use of these studies in EPA's two-city risk assessment. Both of these topics are also discussed below in this unit.

(i) *Studies available for inclusion in the criteria review.* With some exceptions, most of the above commenters cited somewhat similar lists of ''negative'' studies that they argue EPA ignored or downplayed in arriving at conclusions on consistency and coherence. Of the most commonly cited studies, the following were available for inclusion in the Criteria Document: daily mortality studies by Styer et al. (1995), Lyon et al. (1995), Li and Roth (1995), Moolgavkar (1995a,b), Wyzga and Lipfert (1995), Lipfert and Wyzga (1995), and Samet et al. (1995, 1996a,b); the long-term exposure mortality study by Abbey et al. (1991); and the re-examination of the Six-City mortality results (Dockery et al., 1993) by Lipfert (1995).

The written record of EPA's evaluations of these studies effectively refutes the claim that the Agency ignored any of these studies and supports the treatment the Agency accorded to each of them. All of the studies available to EPA at the time of CASAC closure on the PM Criteria Document (March 1996) were examined for inclusion in the Criteria Document and Staff Paper, which form the basis for the PM proposal. ''Negative''[10] studies were evaluated in detail along with ''positive'' studies when they were found to have no critical methodological deficiencies, or to point out strengths and limitations. Studies that had more serious problems were generally discussed in less detail, whether positive or negative, than studies with fewer or small deficiencies. The EPA assessments were evaluated by peer reviewers, by CASAC, and by the public.

Most of the short-term exposure studies cited above in this unit are reanalyses and extensions of PM/mortality studies that had been published by other investigators. In general, the Criteria Document concluded that the most comprehensive and thorough reanalyses were those in the series conducted for the HEI, which reanalyzed data sets used in studies from six urban areas in Phase I.A (Samet et al., 1995)[11], with extended analyses for Philadelphia in Phase I.B (Samet et al., 1996a,b). The most important finding in the HEI Phase I.A reanalyses of the six areas is ''the confirmation of the numerical results of the earlier analyses of all six data sets'' (HEI, 1995)[12]. After replicating the original investigators' analyses, Samet et al. (1995) also found similar results analyzing the data using an improved statistical model. The HEI Oversight Committee found

> [I]t is reasonable to conclude that, in these six data sets, daily mortality from all causes combined, and from cardiovascular and respiratory causes in particular, increases as levels of particulate air pollution indexes increase. [HEI, 1995]

It is important to note that these reanalyses by respected independent scientists confirm the reliability and reproducibility of the work of the original investigators, particularly in view of the concerns some commenters have expressed about EPA's reliance on a number of PM studies published by these authors.

The Phase I.A HEI results for Philadelphia also found that it was difficult to separate the effects of PM from those of co-occurring SO_2, in agreement with the Moolgavkar et al.(1995a) analysis. Subsequent HEI work, and several of the other so-called ''negative'' studies cited above in this unit, further examined this issue in terms of confounding or effects modification by one or more co-occurring gaseous pollutants or weather. Contrary to commenters' claims, this issue and these studies received considerable attention in the Criteria Document and Staff Paper, and the overall implications and conclusions from these assessments were summarized in the proposal. In particular, the so-called ''negative'' and other findings of Moolgalvkar et al. (1995a,b) in their Philadelphia and Steubenville studies were discussed in great detail in section 12.6 of the PM Critera Document and compared to those of the original investigators (Schwartz and Dockery, 1992a,b) and other investigators (Li and Roth, 1995; Wyzga and Lipfert, 1995). Further analytical studies of the Philadelphia data set were carried out by HEI (Samet et al., 1996a,b) and have largely resolved many of the uncertainties in the earlier analyses; in EPA's opinion, these studies supersede the results of the original investigators (Schwartz and Dockery, 1992a) and the several earlier reanalyses, including Moolgavkar (1995a), Moolgavkar and Luebeck (1996), Li and Roth (1995), Wyzga and Lipfert (1995), and Samet et al. (1995). Even though TSP is not the best PM indicator for health effects, since it includes a substantial fraction of non-thoracic particles, the extended Criteria Document assessment (U.S. EPA, 1996a, pp. 12-291 to -299; 12-327) of the Phase I.B HEI analyses in Philadelphia (Samet et al., 1996a,b) serves to support the following findings:

(1) The mortality effects estimates for TSP do not depend heavily on statistical methods when appropriate models are used.

(2) Estimated PM effects are not highly sensitive to appropriate methods for adjusting for time trends and for weather.

(3) Air pollution has significant health effects above and beyond those of weather.

(4) Copollutants such as ozone, CO, and NO_2 may be important predictors of mortality, but their effects can be substantially separated from those of TSP and SO_2.

(5) The health effects of TSP in Philadelphia cannot be completely separated from SO_2, which is itself a precursor of fine particles, based solely on the epidemiological analyses in this single city.

The most recent HEI Oversight Committee comments on these studies (HEI, 1997), which were submitted to the docket by HEI, state that:

> Although individual air pollutants (TSP, SO_2, and ozone) are associated with increased daily mortality in these data, the limitations of the Philadelphia data make it impossible to establish that particulate air pollution alone is responsible for the widely observed associations between increased mortality and air pollution in that city. All we can conclude is that it appears to play a role. [HEI, 1997; p.38.]

While recognizing the limitations in the conclusions that can be made based on studies in a single city, the Oversight Committee endorses the approach taken by EPA in evaluating a broader set of epidemiological studies:

> Consistent and repeated observations in locales with different air pollution profiles can provide the most convincing epidemiological evidence to support

[10] The term ''negative'' studies, as used in these comments, should not be construed to mean those in which there is a negative effects estimate (either significant or non-significant) for the nominal cause. As used by these commenters, the term also includes statistically non-significant positive effect estimates. In other words, the commenters define ''positive'' studies as including only those in which the effect estimate is both positive and statistically significant.

[11] Data sets were those used in the original studies by Dockery et al. (1992) for St. Louis and Eastern Tennessee; Pope et al. (1992) for Utah Valley; Schwartz and Dockery (1992a) for Philadelphia; Schwartz (1993) for Birmingham; and a portion of the Santa Clara data from Fairley (1990). The data set from the Moolgavkar et al. (1995a) Philadelphia reanalysis was also included (Samet et al., 1995).

[12] The HEI Board of Directors appointed an eight member Oversight Committee consisting of leading scientists in several disciplines relevant to air pollution epidemiology to oversee key aspects of the project and to prepare HEI's assessment of the results.

generalizing the findings from these models. This has been the approach reported by the EPA in its recent Criteria Document and Staff Paper. [HEI, 1997; p. 38.]

As noted in the proposal, based on this approach, EPA's assessment of numerous mortality studies concludes that when studies are evaluated on an individual basis, the PM-effects associations are valid and, in a number of studies, not seriously confounded by co-pollutants (U.S. EPA, 1996a; p. 13-57); and when a collection of studies from multiple areas with differing concentrations of PM and co-pollutants are examined together, the association with PM_{10} remains reasonably consistent across a wide range of concentrations of these potentially influential pollutants (U.S. EPA, 1996a; p. 12-33; U.S. EPA, 1996b; p. V-55).

In addition to relying on the most comprehensive and best analyses in evaluating the reanalysis in Philadelphia and other areas, the Criteria Document gave less weight to both so-called ''negative'' and ''positive'' studies with methodogical limitations. In particular, EPA agreed with the epidemiological experts on CASAC (Lippmann et al., 1996; Samet, 1995) that the Li and Roth (1995) study approach of using a ''panoply'' of different modeling strategies to produce seemingly conflicting findings provides little useful insight and is superseded by the HEI report. The attempt by Lipfert and Wyzga (1995) to address relative effects of different pollutants was considered inconclusive (Lippmann et al., 1996) and flawed by the use of a metric (elasticity) that ignores the absolute concentrations of the pollutants being compared (see Response to Comments).

Further, the Steubenville studies and reanalyses (Schwartz and Dockery, 1992b; Moolgavkar, 1995b) were discussed in detail to examine methodologies, and the differences in relative risks between the two were regarded as small (U.S. EPA, 1996a, p. 12-280 to 283). Both studies used TSP as the PM indicator variable, and they are augmented by the more recent findings of Schwartz et al. (1996) that examine PM_{10} and its components. The mixed results by Lyon et al. (1995) in Utah Valley are compromised by loss of information related to the methodology (U.S. EPA, 1996a, p. 12-58). As noted above, subsequent reanalyses of the Utah Valley study by HEI (Samet et al., 1995) as well as by Pope and Kalkstein (1996) confirmed the original findings of Pope et al. (1992) using different model specifications. The Salt Lake City study by Styer et al. (1995) was mentioned in the PM Criteria Document, but received little discussion because aspects of the methodological approach limited its statistical power to detect effects. The analysis of Chicago mortality data in the same paper shared these problems, particularly for seasonal analyses; in this larger city, they nonetheless found significant associations on an annual basis between PM_{10} and mortality that are consistent with other studies. In short, the record shows that EPA did not ignore these short-term exposure studies cited by commenters; moreover, EPA's assessment of these studies is consistent with the views of four researchers on the CASAC panel who have extensive involvement in conducting population studies of air pollution (Lippmann et al., 1996).[13]

Similarly, EPA believes that appropriate treatment and weight were given to studies of long-term exposure and mortality. EPA concluded that the lack of associations in the Abbey et al. (1991) prospective cohort study were not inconsistent with two other such studies because the use of days of peak TSP levels as the PM indicator (instead of PM_{10} or $PM_{2.5}$) is inappropriate for California cohorts exposed to both urban smog and fugitive dust episodes, and the overall sample size may have been too small to detect significant effects (U.S. EPA, 1996b; pp. V-17 to -18). The inadequacy of Lipfert's (1995) application of state-wide average sedentary lifestyle data to adjust mortality for the six cities studied by Dockery et al. (1993), in which superior subject-specific body mass index data had already been considered, was also noted and addressed in the Staff Paper (U.S. EPA, 1996b; p. V-16). Again, EPA did not ignore these studies; the rationale for giving them less weight was clearly articulated in the documents reviewed by CASAC and judged appropriate for use in standard setting.

While the proposal presents only a summary discussion of key Criteria Document and Staff Paper findings, EPA believes that discussion is fully consistent with the state of the science. Furthermore, the proposal highlights the nature of alternative viewpoints on the epidemiology in a quotation from the Criteria Document (61 FR 65644, December 13, 1996) and cites explicitly the views of most of the authors noted above in this unit (Moolgavkar et al., 1995b; Moolgavkar and Luebeck, 1996; Li and Roth, 1995; Samet et al., 1996; Wyzga and Lipfert, 1995). The proposal also summarizes EPA conclusions based on all of the literature as assessed in the Criteria Document and Staff Paper with respect to issues raised in these and other studies, including potential confounding by independent risk factors such as weather and other pollutants, choice of statistical models, use of outdoor monitors, and exposure misclassification.

More specifically, in the proposal EPA has not ignored the view advanced by some that the results of individual studies of multiple pollutants, such as the HEI Philadelphia studies, are more suggestive of an ''air pollution'' effect than an effect of PM alone. Indeed, the proposal notes that it is reasonable to expect that other pollutants may play a role in modifying the magnitude of the estimated effects of PM on mortality, either through pollutant interactions or independent effects (61 FR 65645, December 13, 1996). Based on the large body of evidence at hand, however, EPA cannot accept the suggestion that such multi-pollutant studies are in any way ''negative'' with respect to EPA's conclusions that PM, alone or in combination with other pollutants, is associated with adverse effects at levels below those allowed by the current standards. This conclusion is based not only on the consistency of PM effects across areas with widely varying concentrations of potentially confounding copollutants, but also on the extended analyses of the Philadelphia studies in the Criteria Document and Staff Paper.

Because commenters have tended to ignore the latter analyses, it is appropriate to summarize them here briefly. As noted above in this unit, the Criteria Document assessment of the Philadelphia studies finds that PM can reasonably be distinguished from potential effects of all pollutants except SO_2. The Staff Paper builds on this analysis through an integrated assessment that draws on information from atmospheric chemistry, human exposure studies, and respiratory tract penetration results to provide insight as to which of these two pollutants is more likely to be responsible for mortality in the elderly and individuals with cardiopulmonary disease (U.S. EPA 1996b; pp. V-46 to -50). That assessment notes that the inhalable (PM_{10}), including the fine ($PM_{2.5}$), components of TSP are more likely than SO_2 to penetrate and remain indoors where the sensitive population resides most of the time.[14] In addition, these PM

[13] Their March 20, 1996 letter to the Administrator concludes that the HEI analysis of Philadelphia supersedes earlier analyses, specifically Moolgavkar et al. (1995a), Lipfert and Wyzga (1995), and Li and Roth (1995), and points out the limitations of Styer et al. (1995).

[14] In response to comments on this rulemaking, some papers submitted by industry commenters

Continued

components, especially $PM_{2.5}$, penetrate far more effectively to the airways and gas exchange regions of the lung than does SO_2. Furthermore, in Philadelphia, it is possible that SO_2 is a surrogate for fine particulate acid sulfates. For these reasons, even though statistical analyses of the Philadelphia data set cannot fully distinguish between these two highly correlated pollutants, EPA believes that the weight of the available evidence from an integrated assessment more strongly supports the notion that PM is playing an important direct role in the observed mortality effects associations in Philadelphia. Moreover, as noted above in this unit, in some other locations with significant PM-mortality associations, ambient SO_2 levels are too low to confound PM.

(ii) *Recent studies available after completion of criteria review.* As noted above in this unit, other studies cited by some commenters as so-called ''negative'' evidence ignored by EPA were published or otherwise made available only after completion of the PM Criteria Document. EPA agrees that it did not rely on these studies, based on its long-standing practice of basing NAAQS decisions on studies and related information included in the pertinent air quality criteria and available for CASAC review.[15] Although EPA has not relied on such studies in this review and decision process, the Agency nevertheless has conducted a provisional examination of these and other recent studies to assess their general consistency with the much larger body of literature evaluated in the Criteria Document.[16] EPA has placed its examination of recent studies in the rulemaking docket.

Among the most frequently cited new studies relied on by commenters were Davis et al. (1996), Moolgavkar et al. (1997), and Roth and Li (1997). Davis et al. (1996) conducted a reanalysis of the Birmingham mortality data set originally investigated in Schwartz (1993). At the time of the close of the public comment period, the paper based on this manuscript had not been accepted for publication in a peer reviewed journal (Sacks, 1997). Commenters nevertheless highlight the authors' claim that ''when humidity is included among the meteorological variables (it is excluded in the analysis by Schwartz [1993]), we find that the PM_{10} effect is not statistically significant.'' EPA's review found important factual errors in this study. Contrary to Davis et al., Schwartz did include humidity in his 1993 study, and his finding of a hot-and-humid-day effect was reported there. In addition, the PM-related variables used by Davis et al. in their manuscript were not, as the authors claimed, the same as those in Schwartz (1993). Davis et al. also used a different humidity indicator, specific humidity. Reanalysis by one of the co-authors (R. Smith, personal communication, February 8, 1997) showed that when Schwartz's PM metric was used, the estimated PM_{10} effect was of about the same magnitude, and statistically significant at the 0.05 level, even using the characterization of humidity effect proposed by Davis et al. It therefore appears that the Davis et al. PM_{10} result was, in fact, consistent with that of Schwartz, and robust against a very different weather model specification.

Based on its examination of both the content and the publication status of this study, EPA believes the heavy reliance and attention given to it are misguided. In contrast to commenters' assertions, this study does not contradict EPA's conclusions with respect to consistency of the epidemiological evidence and confounding by weather variables; indeed, the consideration of the corrected results would actually support EPA's conclusions. EPA believes this example reinforces the importance of relying on peer reviewed studies and also conducting the kind of critical examination of such studies that takes place in the criteria and standards review process.

Several commenters note that Roth and Li (1997) also reexamined the Birmingham mortality data, as well as hospital admissions data from Schwartz (1994), and produced a number of negative and inconsistent results that depend on temperature effects and choice of statistical model. Preliminary findings from this study were presented by Roth at the May 1996 CASAC meeting. CASAC epidemiologists and statisticians at the meeting pointed out a number of shortcomings, both in the analytical strategy and in details of the models being evaluated.[17] As discussed in more detail in the Response to Comments, the materials from Roth and Li (1997) recently provided to EPA as attachments to public comments show that the deficiencies pointed out at the May 1996 CASAC meeting have not been adequately addressed. EPA concludes that this study does not support commenters' claims.

The paper recently accepted for publication by Moolgavkar et al. (1997) examines hospital admissions and air pollution in Minneapolis and Birmingham and comes to different conclusions than earlier investigators with respect to the role of PM_{10}. While the paper is a useful addition to the literature, the authors clearly do not attempt to replicate the original studies, making the kind of direct comparisons suggested by commenters difficult. The paper finds an air pollution effect in one city that implicates ozone but is unable to separate effects of PM from a group of other pollutants. EPA's provisional examination of this study raises some questions about the methodology, which might usefully be supplemented to further separate pollutants as was done by Samet et al. (1996a,b) in Philadelphia, and about the authors' interpretation of the results in both cities. In any event, EPA does not believe this study negates the PM associations with hospital admissions

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make statements that are in substantial agreement with these staff conclusions with respect to the likelihood of SO_2 penetrating to indoor environments and the lesser likelihood of affecting sensitive populations indoors (Lipfert and Wyzga, 1997; Lipfert and Urch, 1997).

[15] Since the 1970 amendments, the EPA has taken the view that NAAQS decisions are to be based on scientific studies that have been assessed in air quality criteria [see e.g., 36 FR 8186 (April 30, 1971) (EPA based original NAAQS for six pollutants on scientific studies discussed in the air quality criteria and limited consideration of comments to those concerning validity of scientific basis); 38 FR 25678, 25679-25680 (September 14, 1973) (EPA revised air quality criteria for sulfur oxides to provide basis for reevaluation of secondary NAAQS)]. This longstanding interpretation was strengthened by new legislative requirements enacted in 1977 (section 109(d)(2) of the Act; section 8(c) of the Environmental Research, Development, and Demonstration Authorization Act of 1978) for CASAC review of air quality criteria and reaffirmed in EPA's decision not to revise the ozone standards in 1993. 58 FR 13008, 13013-13014 (March 9, 1993). Some of the commenters now criticizing EPA for not considering the most recent PM studies strongly supported the Agency's interpretation in the 1993 decision (UARG, 1992).

[16] As discussed in EPA's 1993 decision not to revise the NAAQS for ozone, new studies may sometimes be of such significance that it is appropriate to delay a decision on revision of NAAQS and to supplement the pertinent air quality criteria so the new studies can be taken into account. 58 FR at 13014, March 9, 1993. In the present case, EPA's provisional examination of recent studies suggests that reopening the air quality criteria review would not be warranted even if there were time to do so under the court order governing the schedule for this rulemaking. Accordingly, EPA believes that the appropriate course of action is to consider the newly published studies during the next periodic review cycle.

[17] For example, commenting on the Roth examination of alternative model specifications, Dr. Stolwijk noted ''If you select out of his [Roth's] matrix the things that other people have done, he comes to a different conclusion than when he takes his whole matrix * * *. [Y]ou are going to get a random effect that shows that there is no effect. He [Roth] did this, I think, on purpose in this case. Most epidemiologists, I think, have been trained to limit their observations to something that they can state or would have stated before they started and observe that and base their conclusions on it'' [U.S. EPA 1996(c); May 17, 1996 Transcript, pages 45-46].

reported in a number of other studies cited in the Criteria Document.

Another recent paper by Lipfert and Wyzga (1997) provides analyses suggesting that differential measurement error might account for some or all of the observation by Schwartz et al. (1996) that daily mortality is more strongly associated with fine ($PM_{2.5}$) than with coarse ($PM_{10-2.5}$) PM. EPA staff and CASAC accounted for this possibility, however, and it was factored into both the Staff Paper and CASAC recommendations.[18]

Some commenters have highlighted selected individual papers or summaries from the APHEA[19] project conducted in Europe, and from Roth (1996), calling attention particularly to negative results found in heavily polluted regions of Eastern Europe. EPA notes that a number of the recent APHEA and other studies in Western Europe have shown significant associations between mortality and air pollution including PM, and that a meta-analysis of 12 Western and Central-eastern European studies ''is supportive of a causal association between PM and SO_2 exposure and all-cause mortality'' (Katsouyanni et al., 1997). The Eastern and Western European studies used differing measurement methods for PM, including PM_{10}, gravimetric ''suspended particles,'' and the British Smoke method.[20] The differences in aerometry and the substantial differences in location and strength of primary PM emissions sources in central and eastern Europe as compared to western Europe or the U.S. might well explain the different results in these unique areas. Consequently, integration of these results would involve comprehensive examination of the various PM instruments used, monitor siting in relation to sources, mass calibration procedures and other aspects of these studies.[21] EPA notes that a number of European authorities, who are familiar with this recent literature, have proceeded with recommendations to strengthen their health guidelines, risk assessments, or regulations for PM.[22]

Aside from the recent literature cited by these commenters, there are a number of other recent epidemiological studies that, if considered in today's decision, would tend to support EPA's conclusions about the effects of PM at lower concentrations, assuming their results were accepted following a full review in the criteria and CASAC process. For example, in addition to the APHEA studies, several other recent epidemiologic studies have reported significant positive associations between PM and health effects (Lipsett et al., 1997; Peters et al., 1997; Borja-Aburto et al., 1997; Delfino et al., 1997; Scarlett et al., 1996; Woodruff et al., 1997; Wordley et al., 1977). In addition, a number of recent toxicologic papers have been accepted or appear in proceedings (Costa and Dreher, 1997; Killingsworth et al., 1997; Godleski et al., 1997) that involve exposure to concentrated ambient fine particles or PM constituents and appear to provide supportive evidence as to the plausibility of the effects that have been reported epidemiologically. If considered in this decision, these studies would also provide biological support for the epidemiological observation that certain susceptible groups (notably those with cardiopulmonary disease) are most likely to be affected by PM, again assuming the results were sustained in the full criteria and CASAC review process.

In summary, EPA has conducted a provisional assessment of the more recent scientific literature. Based on this provisional assessment, EPA disagrees with commenters' assertion that full consideration of selected new studies in this decision would materially change the Criteria Document and Staff Paper conclusions on the consistency and coherence of the PM data, or on the need to revise the current standards.

(iii) *Other specific comments on the epidemiological studies.* Aside from their assertion that EPA ignored or downplayed particular studies, this second group of commenters raise additional objections, based on the statistical modeling strategies used and the potential importance of personal exposure misclassification, to EPA's conclusions regarding the consistency of the epidemiological evidence. EPA conclusions on these topics were summarized in the proposal and supported by extensive treatments in the Criteria Document and Staff Paper. With respect to the first issue, commenters argued that sufficient flexibility exists in the analyses of large data sets that it may be possible to obtain almost any result desired through choice of statistical method. Analytical choices include the specific statistical model; methods used to adjust for seasonal variation and the trends in the data; treatment of other variables (e.g., other pollutants, weather, and day of week); ''lag'' structure; and study population.

A more detailed discussion of this issue, which expands on the assessment summarized in the Criteria Document, is included in the Response to Comments. In summary, EPA must reject commenters' contention that legitimate alternative analyses can obtain ''almost any result.'' As outlined above in this unit, EPA's detailed reviews of individual studies have shown that not all methods are equally valid or legitimate. Moreover, strong arguments can be made that the methods and analytical strategies in the studies EPA relied upon are more appropriate approaches than those cited by commenters (e.g., Li and Roth, 1995; Lipfert and Wyzga, 1995; Davis et al., 1996; Roth and Li, 1997). While not all studies have addressed each of the above issues in this unit equally well, the most comprehensive analyses of these issues (e.g., Samet et al., 1995, 1996a,b; Pope and Kalkstein, 1996), as well as the EPA analyses comparing study results for each issue (U.S. EPA, 1996a, pp. 12-261 to 12-305) found that the authors of studies on which EPA

[18] CASAC panelists recommended a discussion of this issue in the Staff Paper. The Staff Paper notes: ''While greater measurement error for the coarse fraction could depress a potential coarse particle effect, this would not explain the results in Topeka relative to other cities. Even considering relative measurement error, these results provide no clear evidence implicating coarse particles in the reported effects.'' (U.S. EPA, 1996b p. V-64). EPA's provisional examination of the Lipfert and Wyzga (1997) paper in the Response to Comments, finds that it is implausible that most of the effect attributed to $PM_{2.5}$ could in fact be due to $PM_{10-2.5}$, since differential measurement error cannot make a weaker effect appear stronger than a stronger one, except under extremely unusual circumstances.

[19] The APHEA (Air Pollution and Health: a European Approach) project was supported by the European Union Environment 1991-1994 Programme to investigate the possible short-term health effects of exposure to low or moderate levels of ambient air pollutants. Eleven European research groups carried out studies in 15 cities (Amsterdam, Athens, Barcelona, Bratislava, Cracow, Helsinki, Koln, Lodz, London, Lyon, Milan, Paris, Poznan, Rotterdam and Wroclaw) in which air pollutant concentration data had been collected for at least 5 years. Initial findings of studies on mortality and hospital admissions were published in a series of papers in Supplement 1 to the Journal of Epidemiology and Community Health in 1996 and a meta-analysis of the mortality data from 12 cities is currently in press (Katsouyanni et al., 1997).

[20] The Roth et al. (1997) study in Prague used a measurement termed ''suspended particles'' that appears to be close to TSP. The relation of this indicator to PM_{10} or $PM_{2.5}$ in this city is not reported. Moreover, this study uses a variant of the problematic methodology in the Roth analyses cited above.

[21] These concerns are consistent with EPA's treatment of a number of European and South American studies that are included in the Criteria Document and contributed to the evaluation of the epidemiology in Chapter 12. Because of differences in aerometry methods and characteristic source classes between North America and other regions of the world, however, the integrative assessment chapter reported results only from studies conducted in the U.S. and Canada (cf. Tables 13-3 to 13-5) in reaching quantitative conclusions for effects estimates.

[22] See, for example, the United Kingdom Air Quality Strategy, 1997; Swiss Federal Commission of Air Hygiene, 1996; World Health Organization Revised Air Quality Guidelines for Europe, In Press).

chiefly relied made appropriate modeling choices. The Criteria Document concludes that: ''[T]he largely consistent specific results, indicative of significant positive associations of ambient PM exposures and human mortality/morbidity effects, are not model specific, nor are they artifactualy derived due to misspecification of any specific model. The robustness of the results of different modeling strategies and approaches increases our confidence in their validity [U.S. EPA, 1996a, p. 13-54].'' While it is true, as evidenced in Li and Roth (1995), that PM-effects data can be randomly manipulated to produce apparently conflicting results, commenters have provided no evidence that different plausible model specifications could lead to markedly different conclusions.

Some commenters have expressed concerns about the reliability of the epidemiological results because some studies showed a lack of correlation in cross-sectional comparisons between outdoor PM measured at central locations and indoor or personal exposures to PM (which includes PM from the outdoor, indoor and personal environments).[23] EPA acknowledged and responded to this issue in chapter 7 of the Criteria Document and the proposal (61 FR 65645, December 13, 1996). The major premise underlying commenters' arguments on this issue is incorrect.[24] The question is not whether central monitoring site measurements contain a signal reflecting actual exposures to total PM from both outdoor and indoor sources at the individual level; the relevant question is whether central monitoring site measurements contain a signal reflecting actual exposures to ambient PM for the subject population, including both ambient PM, while individuals are outdoors, and ambient PM that has infiltrated indoors, while individuals are indoors. The PM standards are intended to protect the public from exposure to ambient PM, not PM generated by indoor or personal sources. There is ample evidence, as discussed in chapter 7 of the Criteria Document, that personal exposure to ambient PM, while outdoors and while in indoor micro-environments, does correlate on a day-to-day basis with concentrations measured at properly sited central monitors (U.S. EPA, 1996a, p. 1-10). EPA has, therefore, concluded that it is reasonable to presume that a reduction in ambient PM concentrations will reduce personal exposure to ambient PM, and that this will protect the public from adverse health outcomes associated with personal exposure to ambient PM.

Commenters have also restated theoretically based concerns on a related issue, namely errors in the measurement of the concentrations of air pollutants, that was summarized in the proposal. In multiple pollutant analyses, measurement error or, more generally, exposure misclassification, could theoretically bias effects estimates of PM or co-pollutants in either direction, introducing further uncertainties in the estimated concentration-response relationships for all pollutants (U.S. EPA, 1996b, pp. V-39 to V-43). Relevant insights on this issue in material appended to public comments (Ozkaynak and Spengler, 1996) have prompted an expanded statistical analysis of the conditions under which such errors could inflate the magnitude of the effects estimates or the significance of PM relative to gaseous pollutants, as has been suggested by Lipfert and Wyzga (1995). This analysis, which is summarized in the Response to Comments, finds that the conditions under which measurement error could inflate the effects estimates or significance of PM relative to other pollutants are restricted to a limited set of statistical relationships. Commenters have not provided evidence that suggest such conditions are likely to occur with respect to the measurement of ambient PM in relation to those for gaseous co-pollutants commonly used in epidemiological studies.[25] Therefore, it appears unlikely that measurement and exposure errors for PM and other pollutants have inflated the estimated effects of PM, even in multivariate analyses. More importantly, the available evidence on the consistency of the PM-effects relationships in multiple urban locations, with widely varying indoor/outdoor conditions and a variety of monitoring approaches, makes it less likely that the observed associations of PM with serious health effects at levels allowed under the current NAAQS are an artifact of errors in measurement of pollution or of exposure (U.S. EPA 1996b, pp. V-39 to V-43).

(iv) *Comments on the PM risk assessment.* As noted in the proposal, uncertainties about measurement errors, exposure misclassification, and the relative effects of copollutants are more important to the quantitative estimates of risk associated with PM than to the existence of valid PM-effects associations at levels found in recent studies. A number of commenters argued that EPA's risk assessment is flawed and incomplete. Chief among the reasons they advanced is that the assessment is based on the same epidemiological studies these commenters argued are inadequate for the reasons summarized and responded to above. Specific comments also addressed the extent to which the risk assessment might overstate risk estimates because it assumes a linear no-threshold relationship and the use of studies that might inflate PM risk due to inadequate consideration of co-pollutants and other potential confounders. The full risk assessment acknowledges these issues and uncertainties, however, and it illustrates the potential influence of such uncertainties in sensitivity analyses (U.S. EPA 1996b; chapter 6, appendix F; Abt Associates, 1996a,b; 1997a,b). For example, Figure 2c in the proposal (61 FR 65653, December 13, 1996)

[23] Paradoxically, some commenters have argued (e.g., Valdberg, 1997) that the PM results are confounded because the weather and other factors that cause daily variations in outdoor pollution will cause similar daily variations in indoor generated air pollution. For this to be true, outdoor ambient pollution concentrations would have to be correlated with personal exposure to indoor generated air pollution such as that from smoking, cleaning, and cooking. This argument is logically inconsistent with the other comments on the lack of any such correlation with personal exposure, and these commenters have offered no scientific evidence to support their claim. In response, EPA has performed and included in the Response to Comments a numerical analysis of the relevant information from the PTEAM exposure study that finds no evidence for such a correspondence in the actual data.

[24] As documented in Chapter 7 of the Criteria Document, time-series community studies observe the effects of varying levels of ambient air pollution; therefore the effects of indoor-generated air pollution would be independent of and in addition to the effects found in these epidemiological studies. Commenters apparently believe EPA is claiming such studies are detecting the effects of daily variations in total PM personal exposure from indoor and outdoor sources. This misunderstanding is evidenced, for example, by Wyzga and Lipfert's (1995) treatment of the difference between ambient monitors and actual personal exposures as ''exposure errors'' and Brown's comment for API that ''if (ambient) PM is causally related to mortality/morbidity, then it is personal PM exposure that must be reduced to have an effect.'' On the contrary, it is personal exposure to ambient PM that must be reduced to address the risk identified in community air pollution studies. Any lack of significant correlation between outdoor PM concentrations and personal exposure to total PM from all sources is irrelevant, except to the extent it may decrease the power of time-series studies to detect the effects of ambient pollution.

[25] The EPA analysis finds that in order for measurement errors in one pollutant variable to significantly bias the estimated effect of another pollutant, three conditions are necessary: (1) The measurement error in the poorly measured pollutant must be very large, roughly at least the same size as the population variability in that pollutant; (2) the poorly measured pollutant must be highly correlated with the other pollutant, either positively or negatively; and (3) the measurement errors for the two pollutants must be highly negatively correlated (Response to Comments, Appendix D). This important factor was not considered in Lipfert and Wyzga (1995) or by commenters.

illustrates the potential influence of what appears to be the most significant uncertainty in current information, whether a population threshold exists below which the effects of PM no longer occur (61 FR 65653, December 13, 1996). EPA notes that a full consideration of the uncertainties, including the analysis summarized above on measurement error, suggests that the epidemiological studies might well have understated the total effects of air pollution; thus, both the direction and the extent of any bias in the risk estimates are less clear than commenters suggest.

EPA believes that, even recognizing the large uncertainties, the key qualitative insights derived from the risk assessment and summarized in Unit II.A.3. of this preamble remain appropriate. While not placing great weight on the specific numerical estimates, EPA believes that the risk analysis confirms the general conclusions drawn primarily from the epidemiological results themselves, that there is ample reason to be concerned that exposure to ambient PM at levels allowed under the current air quality standards presents a serious public health problem.

3. *Key considerations informing the decision.* Having carefully considered the public comments on the above matters, EPA believes the fundamental scientific conclusions on the effects of PM reached in the Criteria Document and Staff Paper, and restated in the introduction to this unit, remain valid. That is, the epidemiological evidence for ambient PM, alone or in combination with other pollutants, shows associations with premature mortality, hospital admissions, respiratory symptoms, and lung function decrements. Despite extensive critical examination in the criteria and standards review, these findings cannot be otherwise explained by analytical, data, or other problems inherent in the conduct of such studies. Although the evidence from toxicological studies available during the criteria review has not revealed demonstrated mechanisms that explain the range of effects reported in epidemiological studies, it does not and cannot refute the observation of such effects in exposed populations. Moreover, the effects observed in the recent epidemiological studies at lower PM concentrations are both coherent with each other and plausible based on the categories of effects observed at much higher concentrations in historic air pollution episodes, laboratory studies of PM effects at high doses, and particle dosimetry studies. The consistency of the results from a large number of locations and the coherent nature of the observed results suggest a likely causal role of ambient PM in contributing to the reported effects (U.S. EPA, 1996a; p. 13-1). Many of the studies showing PM effects were conducted in areas where the current PM_{10} standards are largely met, and both the studies and EPA's risk assessment suggest that the collective magnitude of the effects reflects a significant public health problem.

For these reasons, and having considered public comments on this issue, the Administrator concludes that the review of the criteria and standards provides strong evidence that the current PM_{10} standards do not adequately protect public health, and that revision of the standards is not only appropriate, but necessary.

Aside from that conclusion, the appropriateness of continuing to rely on the use of PM_{10} as the sole indicator for revised PM standards is also relevant here. While the basis for decisions on specific indicators is discussed more fully in Unit II.C. of this preamble, this issue is related to the Administrator's decision on the need to revise the standards. Based on both the staff review (U.S. EPA, 1996b, p. VII-3) and the recommendations of some commenters (e.g., California EPA), there are two alternative approaches for providing additional health protection in revising the standards: Adopt tighter PM_{10} standards and/or recognize the fundamental differences between fine and coarse particles and develop separate standards for the major components of PM_{10}, including fine particles. Conceptually, the first approach would give weight to comments that standards should be based on pollutant indicators for which the most data have been collected, with less consideration of the evidence that suggests that the current standards provide adequate protection against the effects of coarse particles, and that tightening the current PM_{10} standards in an attempt to control fine particles would place unnecessary requirements on coarse particles. Because the PM_{10} network is in place, a more stringent PM_{10} standard would also respond to commenters who have expressed a desire for more immediate implementation of revised standards. The second approach is based on the view that, in the long run, more effective and efficient protection can be provided by separately targeting appropriate levels of controls to fine and coarse PM.

The Staff Paper examined this issue in detail (U.S. EPA 1996b, pp. VII-3 to VII-11), and concluded that the available information was sufficient to develop separate indicators for fine and coarse fractions of PM_{10}, based on the recent health evidence, the fundamental differences between fine- and coarse-fraction particles, and implementation experience with PM_{10}. Further, the staff concluded that:

> [C]onsideration of comparisons between fine and coarse fractions suggests that fine fraction particles are a better surrogate for those particle components linked to mortality and morbidity effects at levels below the current standards. In contrast, coarse fraction particles are more likely linked with certain effects at levels above those allowed by the current PM_{10} standards. In examining alternative approaches to increasing the protection afforded by PM_{10} standards, the staff concludes that reducing the levels of the current PM_{10} standards would not provide the most effective and efficient protection from these health effects. [U.S. EPA 1996b; p. 7-45]

As discussed in Unit II.C. of this preamble, the Administrator believes that it is more appropriate to provide additional protection against the risk posed by PM by adding new standards for the fine fraction of PM_{10}, as opposed to tightening the current PM_{10} standards. Although fewer epidemiological studies have used $PM_{2.5}$ and other fine particle indicators (e.g., sulfates, acids), there are nonetheless significant indications from the scientific evidence - drawn from the physicochemical studies of PM, air quality and exposure information, toxicological studies, and respiratory tract deposition data - that this approach will provide the most effective and efficient protection of public health.

Several commenters have argued that the decision on whether to revise the PM standards should be deferred, particularly with regard to fine particle standards, pending establishment and operation of a national monitoring network to characterize fine PM and a research program to reduce uncertainties in the effects information. These commenters expressed concerns that establishing fine PM standards now might result in needless regulation of PM components that may be unrelated to observed health effects. As discussed more fully in Unit II.F. of this preamble, such commenters recommended, at most, that if fine PM standards were established, they should be set at a level ''equivalent'' to the current PM standards.

EPA strongly disagrees that the decision on revising the standards should be delayed to await the results of new PM monitoring and research programs. Under section 109(d) of the Act, EPA's obligation after reviewing the

existing criteria and standards for PM is to make such revisions in the standards and to promulgate such new standards as are appropriate under section 109(b) of the Act. Based on her review of the criteria and standards for PM, the Administrator has concluded that the current standards are not adequate to protect public health and that revisions are appropriate. In the face of the available evidence, a delay in revising the standards would not only be inconsistent with the statute but -- even under the optimistic assumption that the same extensive monitoring and strategy assessment as now contemplated would occur in the absence of a revised standard -- would add approximately 2 years to the time when significant health benefits can be realized, resulting in potentially significant numbers of additional premature deaths and even larger numbers of children and individuals with air pollution-related illness and symptoms. On the other hand, establishing standards now will set into motion the development of implementation programs and monitoring that can be conducted in parallel with additional scientific research, without undue delays inherent in waiting for the research.

The question of which pollutant components to regulate has been an issue since the inception of the first PM standards. Other ambient pollutants (e.g., NO_2 or CO) are uniquely defined as individual chemicals, whether or not they serve as proxies for a larger class of substances (e.g., ozone as an index of photochemical oxidants). Regulating general PM, as opposed to multiple chemical components of PM, raises the spectre of a host of particulate materials of varying composition, size, and other physicochemical properties, not all of which are likely to produce identical effects.

Both EPA's past and present regulatory experience with PM control programs and its successive reviews of the standards have reaffirmed the wisdom of retaining standards that control particles as a group, rather than eliminating such standards and waiting for scientific research to develop information needed to identify more precise limits for the literally thousands of particle components. Each such decision recognized the possibility that potentially less harmful particles might be included in the mix that was regulated, but concluded that the need to provide protection against serious health effects nonetheless required action under section 109 of the Act. The success of this approach is evident in early U.S. control programs that dramatically reduced ''smoke'' and ''TSP'' in major cities in the 1960's and 1970's and in the continued improvement in air quality through the current PM standards. The major refinements that have been recommended through the course of reviews of PM standards have been to improve the focus of control efforts by defining scientifically based size classes (i.e., moving from TSP to PM_{10} and now, $PM_{2.5}$) that will permit more effective and efficient regulation of those fractions most likely to present significant risks to health and the environment.

As discussed in Unit II.C. of this preamble, the current review has examined the available evidence to determine whether it would tend to support inclusion or exclusion of any physical or chemical classes of PM, for example sulfates, nitrates, or ultra-fine particles. That examination concludes that, while both fine and coarse particles can produce health effects, the fine fraction appears to contain more of the reactive substances potentially linked to the kinds of effects observed in the recent epidemiological studies (U.S. EPA 1996b, section V.F.). However, the available scientific information does not rule out any one of these components as contributing to fine particle effects. Indeed, it is reasonable to anticipate that no single component will prove to be responsible for all of the effects of PM.

EPA recognizes that whether the standards are set for PM_{10} only or also for fine particles, there are uncertainties with respect to the relative risk presented by various components of PM. In this regard, the Administrator places greater weight on the concern that by failing to act now, the PM NAAQS would not control adequately those components of air pollution that are most responsible for serious effects, than on the possibility they might also control some component that is not. EPA believes that moving simultaneously to establish standards based on the best available scientific evidence and to conduct an aggressive monitoring and scientific research program designed to help resolve current uncertainties is a prudent and responsible approach for addressing both the risks and the uncertainties inherent in this important public health issue.

In summary, given the evidence that PM-related health effects appear likely to occur at levels below the current standards, the serious nature and potential magnitude of the public health risks involved, and the need to consider the fine and coarse fractions as distinct classes of particles, the Staff Paper and the CASAC (Wolff, 1996b) concluded that revision of the current standards is clearly appropriate. Moreover, at their May 1996 public meeting (U.S. EPA, 1996c), and in separate written comments (including Lippmann et al., 1996), a majority of CASAC panel members recommended revisions that would strengthen the health protection provided by the current PM standards. Based on the rationale and recommendations contained in the Staff Paper and the advice of CASAC, and taking into account public comments, the Administrator concludes that it is appropriate at this time to revise the current PM standards to increase the public health protection provided against the known and potential effects of PM identified in the air quality criteria.

C. Indicators of PM

In establishing adequately protective, effective, and efficient PM standards, it is necessary to specify the fraction of particles found in the ambient air that should be used as the indicator(s) for the standards. In this regard, EPA concludes that the most recent assessment of scientific information in the Criteria Document, summarized in chapters IV and V of the Staff Paper, continues to support past staff and CASAC recommendations regarding the selection of size-specific indicators for PM standards. More specifically, EPA continues to find that the following conclusions reached in the Staff Paper and in the 1987 review remain valid:

(1) Health risks posed by inhaled particles are influenced both by the penetration and deposition of particles in the various regions of the respiratory tract and by the biological responses to these deposited materials.

(2) The risks of adverse health effects associated with deposition of ambient fine and coarse fraction particles in the thoracic (tracheobronchial and alveolar) regions of the respiratory tract are markedly greater than for deposition in the extrathoracic (head) region. Maximum particle penetration to the thoracic region occurs during oronasal or mouth breathing.

(3) The risks of adverse health effects from extrathoracic deposition of general ambient PM are sufficiently low that particles which deposit only in that region can safely be excluded from the standard indicator.

(4) The size-specific indicator(s) should represent those particles capable of penetrating to the thoracic region, including both the tracheobronchial and alveolar regions.

These conclusions, together with information on the dosimetry of particles in humans, were the basis for the promulgation in 1987 of a new size-specific indicator for the PM NAAQS, PM_{10}, that includes particles with an aerodynamic diameter smaller than or equal to a nominal 10 μm. The recent information on human particle dosimetry contained in the Criteria Document provides no basis for changing 10 μm as the appropriate cut point for particles capable of penetrating to the thoracic regions.

As noted in Unit II.B. of this preamble, however, the Staff Paper concludes that continued use of PM_{10} as the sole indicator for the PM standards would not provide the most effective and efficient protection from the health effects of PM (U.S. EPA, 1996b, pp. VII-4 to VII-11). Based on the recent health effects evidence and the fundamental physical and chemical differences between fine and coarse fraction particles, the Criteria Document and Staff Paper conclude that fine and coarse fractions of PM_{10} should be considered separately (U.S. EPA, 1996a, p. 13-93; 1996b, p. VII-18). Taking into account such information, CASAC found sufficient scientific and technical bases to support establishment of separate standards relating to these two fractions of PM_{10}. Specifically, CASAC advised the Administrator that ''there is a consensus that retaining an annual PM_{10} NAAQS * * * is reasonable at this time'' and that there is ''also a consensus that a new $PM_{2.5}$ NAAQS be established'' (Wolff, 1996b).

Some commenters have noted that it is often difficult to distinguish the effects of either fine or coarse fraction particles from those of PM_{10}; this is to be expected because both fractions are themselves components of PM_{10}, and hence not fully independent. EPA believes that it is more meaningful to examine comparisons between the fine and coarse fraction components. Such comparisons presented in the Staff Paper suggest that fine particles are a better surrogate for those components of PM that are linked to mortality and morbidity effects at levels below the current standards (U.S. EPA, 1996b, p. VII-18). Moreover, a regulatory focus on fine particles would likely also result in controls on gaseous precursors of fine particles (e.g., SO_x, NO_x, VOC), which are all components of the complex mixture of air pollution that has most generally been associated with mortality and morbidity effects. The Staff Paper concludes that, in contrast to fine particles, coarse fraction particles are more clearly linked with certain morbidity effects at levels above those allowed by the current 24-hour standard.

Public comments received on the proposed indicators were overwhelmingly in favor of EPA's proposal to maintain PM_{10} as an indicator for PM, whether as an indicator of coarse particles in conjunction with a fine PM standard, or as the sole PM indicator. This near unanimity shows strong support for retaining general PM standards. While a substantial number of commenters supported EPA's proposal to add an indicator for fine PM, a number of other commenters objected to any standard revisions, including addition of a fine PM indicator. Beyond the general points about the basis for any revisions discussed in Unit II.B. of this preamble, these commenters argued either that the available epidemiological data did not provide a basis for separating fine and coarse fraction particles, or that there were not enough fine particle studies to support selecting standard levels. Most of these commenters also expressed concerns that there were insufficient ambient fine particle data by which to evaluate the relative protection afforded by new standards.

EPA notes that issues relating to the basis for separating PM_{10} fractions were addressed in the Criteria Document and/or Staff Paper assessments, and these perspectives were also available for CASAC consideration in developing its recommendations. The proposal states that the main basis for separating the fine and coarse fractions of PM_{10} is that, because they are fundamentally different PM components with significantly different physico-chemical properties and origins (U.S. EPA 1996b, section V.D), separate standards would permit more effective and efficient regulation of PM. While the difficulty in separating these classes in the epidemiological studies is noted above, the preponderance of the available evidence suggests that strategies to control fine particles will more effectively reduce population exposure to substances associated with health effects in the recent epidemiological studies. Although the number of studies using fine PM indicators is more limited than for PM_{10}, there are more than 20 community studies showing significant associations for a consistent set of mortality and morbidity effects. A substantial subset of these studies (Tables V-12 to V-13; U.S. EPA, 1996b) provides a sufficient quantitative basis for selecting standard levels, without the need to rely on estimates based on $PM_{2.5}/PM_{10}$ ratios.

Having considered the public comments on this issue, the Administrator concurs with staff and CASAC recommendations to control particles of health concern (i.e., PM_{10}) through separate standards for fine and coarse fraction particles. The following units outline the basis for the Administrator's decision on specific indicators for fine and coarse fraction particle standards.

1. *Indicators for the fine fraction of* PM_{10}. The Administrator continues to conclude that it is appropriate to control fine particles as a group, as opposed to singling out particular components or classes of fine particles. The more qualitative scientific literature, evaluated in Chapter 11 of the Criteria Document and summarized in section V.C of the Staff Paper, has reported various health effects associated with high concentrations of a number of fine particle components (e.g., sulfates, nitrates, organics, transition metals), alone or in some cases in combination with gases. Community epidemiolgical studies have found significant associations between fine particles or PM_{10} and health effects in various areas across the U.S. where such fine particle components correlate significantly with particle mass. As noted above in this unit, it is not possible to rule out any one of these components as contributing to fine particle effects.[26] Thus, the Administrator finds that the present data more readily support a standard based on the total mass of fine particles. EPA will conduct additional research, in cooperation with other Federal agencies and in partnership with State and local agencies and the private sector, to better identify which species are of concern for human health, and the sources and relative magnitude of such species.

In specifying a precise size range for a fine particle standard, both the staff and CASAC recommended $PM_{2.5}$ as the indicator of fine particles (Wolff, 1996b). The particle diameter reflecting the mass minimum between the fine and coarse modes typically lies between 1 and 3 μm, and the scientific data support a sampling ''cut point'' to delineate fine particles somewhere in this range. Because of the potential

[26] As discussed above, a number of commenters expressed concerns that various portions of fine particles might not be responsible for any observed effects. One group (PG&E, 1997) recommended that nitrates should be excluded from fine PM mass collected on the basis of their assessment of available effects literature on particulate and gas phase inorganic nitrates. Based on an examination of this information as well as the earlier staff assessment, EPA maintains its conclusion that the available evidence is not sufficient to exclude nitrates or any other class of fine particles that are collected by PM monitors comparable to those used in the recent epidemiological studies.

overlap of fine and coarse particle mass in this intermodal region, EPA recognizes that any specific sampling cut point would result in only an approximation of the actual fine-mode particle mass. Thus, the choice of a specific diameter within this size range is largely a policy judgment. The staff and CASAC recommendations for a 2.5 μm sampling cut point were based on considerations of consistency with the community health studies, the limited potential for intrusion of coarse fraction particles into the fine fraction, and availability of monitoring technology.[27] $PM_{2.5}$ encompasses all of the potential agents of concern in the fine fraction, including most sulfates, acids, fine particle transition metals, organics, and ultrafine particles, and includes most of the aggregate surface area and particle number in the entire distribution of atmospheric particles.

The Administrator concurs with the staff and CASAC recommendations and concludes that $PM_{2.5}$ is the appropriate indicator for fine particle standards. As discussed in Unit VI.B. of this preamble, technical details of how $PM_{2.5}$ is to be measured in the ambient air are specified in the Federal Reference Method (40 CFR part 50, Appendix L).

2. *Indicators for the coarse fraction of* PM_{10}. The Criteria Document and Staff Paper conclude that epidemiological information, together with dosimetry and toxicological information, support the need for a particle indicator that addresses the health effects associated with coarse fraction particles within PM_{10} (i.e., $PM_{10-2.5}$). As noted above, coarse fraction particles can deposit in those sensitive regions of the lung of most concern. Although the role of coarse fraction particles in much of the recent epidemiological results is unclear, limited evidence from studies where coarse fraction particles are the dominant fraction of PM_{10} suggest that significant short-term effects related to coarse fraction particles include aggravation of asthma and increased upper respiratory illness. In addition, qualitative evidence suggests that potential chronic effects may be associated with long-term exposure to high concentrations of coarse fraction particles.

In selecting an indicator for coarse fraction particles, the Administrator took into account the views of several CASAC panel members who suggested using the coarse fraction directly (i.e., $PM_{10-2.5}$) as the indicator. However, the Administrator notes that the existing ambient data base for coarse fraction particles is smaller than that for fine particles, and that the only studies of clear quantitative relevance to effects most likely associated with coarse fraction particles have used undifferentiated PM_{10}. In fact, it was the consensus of CASAC that it is reasonable to consider PM_{10} itself as a surrogate for coarse fraction particles, when used together with $PM_{2.5}$ standards. The monitoring network already in place for PM_{10} is large. Therefore, in conjunction with the decision to have separate standards for $PM_{2.5}$, the Administrator concludes, consistent with CASAC recommendations and public comments, that it is appropriate to retain PM_{10} as the indicator for PM standards intended to protect against the effects most likely associated with coarse fraction particles.

D. Averaging Time of $PM_{2.5}$ Standards

As discussed above in this unit, the Administrator has concluded that $PM_{2.5}$ is an appropriate indicator for standards intended to provide protection from effects associated primarily with fine particles. The recent health effects information includes reported associations with both short-term (from less than 1 day to up to 5 days) and long-term (from a year to several years) measures of PM.

On the basis of this information, summarized in chapter V of the Staff Paper and in the rationale presented in the proposal, the Administrator has considered both short- and long-term $PM_{2.5}$ standards.

1. *Short-term $PM_{2.5}$ standard.* The current 24-hour averaging time is consistent with the majority of community epidemiological studies, which have reported associations of health effects with 24-hour concentrations of various PM indicators such as PM_{10}, fine particles, and TSP. Such health effects, including premature mortality and increased hospital admissions, have generally been reported with same-day, previous day, or longer lagged single-day concentrations, although some studies have reported stronger associations with multiple-day average concentrations. In any case, the Administrator recognizes that a 24-hour $PM_{2.5}$ standard can effectively protect against episodes lasting several days, since attainment of such a standard would provide protection on each day of a multi-day episode, while also protecting sensitive individuals who may experience effects after even a single day of exposure.

Although most reported effects have been associated with daily or longer measures of PM, evidence also suggests that some effects may be associated with PM exposures of shorter durations. For example, controlled human and animal exposures to specific components of fine particles, such as acid aerosols, suggest that bronchoconstriction can occur after exposures of minutes to hours. Some epidemiological studies of exposures to acid aerosols have also found changes in respiratory symptoms in children using averaging times less than 24 hours. However, such reported results do not provide a satisfactory quantitative basis for setting a fine particle standard with an averaging time of less than 24 hours, nor do current gravimetric mass monitoring devices make such shorter durations generally practical at present. Further, the Administrator recognizes that a 24-hour average $PM_{2.5}$ standard which leads to reductions in 24-hour average concentrations is likely to lead as well to reductions in shorter-term average concentrations in most urban atmospheres, thus providing some degree of protection from potential effects associated with shorter duration exposures.

2. *Long-term $PM_{2.5}$ standard.* Community epidemiological studies have reported associations of annual and multi-year average concentrations of PM_{10}, $PM_{2.5}$, sulfates, and TSP with an array of health effects, notably premature mortality, increased respiratory symptoms and illness (e.g., bronchitis and cough in children), and reduced lung function. The relative risks associated with such measures of long-term exposures, although highly uncertain, appear to be larger than those associated with short-term exposures. Based on the available epidemiology, and consistent with the limited relevant toxicological and dosimetric information, the Administrator concludes that significant, and potentially independent, health consequences are likely associated with long-term PM exposures.

[27] The National Mining Association (NMA) and related companies submitted comments favoring ultimate selection of a smaller cutpoint of 1 μm (PM_1) to further reduce coarse particle intrusion. EPA considered this approach in developing the Staff Paper and proposal. PM_1 has not been used in health studies, although in most cases collected mass should be similar to those for cutpoints of 2.1 or 2.5 μm. While a PM_1 indicator could reduce intrusion of coarse particles, it might also omit portions of hygroscopic PM components such as acid sulfates, nitrates, and some organic compounds in higher humidity environments picked up by $PM_{2.5}$ measurements. PM_1 sampling technologies have been developed, but have not been widely used in the field to date; there are some concerns about loss of certain organic materials in available models relative to an instrument with a larger size cut. NMA has also recommended consideration of a methodology that could subtract coarse mass from $PM_{2.5}$ measurements where undue coarse particle intrusion resulted in fine standard violations. EPA will evaluate this recommendation in the context of implementation policies.

The Administrator has considered this evidence, which suggests that some health endpoints reflect the cumulative effects of PM exposures over a number of years. In such cases, an annual standard would provide effective protection against persistent long-term (several years) exposures to PM. Requiring a much longer averaging time would also complicate and unnecessarily delay control strategies and attainment decisions.

The Administrator has also considered the seasonality of emissions of fine particles and their precursors in some areas (e.g., wintertime smoke from residential wood combustion, summertime regional acid sulfate and ozone formation), which suggests that some effects associated with annual average concentrations might be the result of repeated seasonally high exposures. However, different seasons are likely of concern in different parts of the country, and the current evidence does not provide a satisfactory quantitative basis for setting a national fine particle standard in terms of a seasonal averaging time.

In addition, the Administrator recognizes that an annual standard would have the effect of improving air quality broadly across the entire annual distribution of 24-hour $PM_{2.5}$ concentrations, although such a standard would not as effectively limit peak 24-hour concentrations as would a 24-hour standard. The risk assessment summarized above found that because such 24-hour peaks contribute much less to the total health risk over a year than the more numerous low- to mid-range $PM_{2.5}$ levels, an annual standard could also provide effective protection from health effects associated with short-term exposures to $PM_{2.5}$ as well as those associated with long-term exposures (see figure 2; 61 FR 65652-65653, December 13, 1996).

3. *Combined effect of annual and 24-hour standards.* For the reasons outlined in Units II.C.1. and 2. of this preamble, the Administrator concluded in the proposal that a short-term $PM_{2.5}$ standard with a 24-hour averaging time can serve to control short-term ambient $PM_{2.5}$ concentrations, thus providing protection from health effects associated with short-term (from less than 1-day to up to 5-day) exposures to $PM_{2.5}$. Further, a long-term $PM_{2.5}$ standard with an annual averaging time can serve to control both long- and short-term ambient $PM_{2.5}$ concentrations, thus providing protection from health effects associated with long-term (seasonal to several years) and, to some degree, short-term exposures to $PM_{2.5}$.

EPA received comparatively few public comments on these proposed averaging times. Those supporting $PM_{2.5}$ standards also strongly supported adopting both annual and 24-hour averaging times. Many of those opposing $PM_{2.5}$ standards, for the reasons discussed in Unit II.B. of this preamble, provided contingent comments that variously supported both averaging times for $PM_{2.5}$ standards in the event the Administrator disagreed with their overall recommendations. Other opponents of $PM_{2.5}$ standards disagreed with having two standards on administrative grounds, or because some CASAC members did not support both averaging times.

The relationship between standards for the two averaging times is discussed below in this unit. In essence, based on its examination of the effects data and air quality relationships, EPA believes that a single $PM_{2.5}$ standard (24-hour or annual) either would not provide adequate protection against effects of concern for all averaging times, or would be inefficient in the sense that it was more stringent than necessary for at least one averaging time. Contrary to commenters who focused on minority CASAC opinions, EPA notes that a clear majority of CASAC supported both 24-hour and annual standards[28]. After considering public comments on averaging time and the rationale outlined above, the Administrator has concluded that both 24-hour and annual $PM_{2.5}$ standards are appropriate.

The Administrator next considered the potential combined effects of such standards on PM concentration levels and distributions. The existing health effects evidence could, of course, be used to assess the form and level of each standard independently, with short-term exposure health effects evidence being used as the basis for a 24-hour standard and the long-term exposure health effects evidence as the entire basis for an annual standard. Some CASAC panel members apparently used this approach as a basis for their views on appropriate averaging times and standard levels. In particular, a few members focused only on a 24-hour $PM_{2.5}$ standard in light of the relative strength of the short-term exposure studies. On the other hand, two members focused only on an annual standard, recognizing that strategies to meet an annual standard would provide protection against effects of both short- and long-term exposures.

[28] Of the 19 panel members who joined in the consensus for $PM_{2.5}$ standards, 17 (90 percent) recommended a 24-hour standard and 13 (70 percent) recommended an annual standard (Wolff, 1996b).

As noted above in this unit, attempting to provide protection for all of the effects identified in long- and short-term PM exposure studies with a single averaging time would result in either inadequate protection for some effects, or unnecessarily stringent control for others. The Administrator has, instead, emphasized a policy approach that considers the consistency and coherence, as well as the limitations, of the body of evidence as a whole, and recognizes that there are various ways to combine two standards to achieve an appropriate degree of public health protection. Such an approach to standard setting, which integrates the body of health effects evidence and air quality analyses, and considers the combined effect of the standards, has the potential to result in a more effective and efficient suite of standards than an approach that only considers short- and long-term exposure evidence, analyses, and standards independently.

In considering the combined effect of such standards, the Administrator notes that while an annual standard would focus control programs on annual average $PM_{2.5}$ concentrations, it would also result in fewer and lower 24-hour peak concentrations. Alternatively, a 24-hour standard that focuses controls on peak concentrations could also result in lower annual average concentrations. Thus, either standard could be viewed as providing both short- and long-term protection, with the other standard serving to address situations where the daily peaks and annual averages are not consistently correlated.

The Administrator proposed that the suite of $PM_{2.5}$ standards could most effectively and efficiently be defined by treating the annual standard as the generally controlling standard for lowering both short- and long-term $PM_{2.5}$ concentrations. In conjunction with the annual standard, the 24-hour standard would serve to provide protection against days with high peak $PM_{2.5}$ concentrations, localized ''hot spots,'' and risks arising from seasonal emissions that would not be well controlled by a national annual standard.

Relatively few public comments were addressed specifically to the proposal that the annual standard be directed toward controlling both 24-hour and annual levels (thereby basing the annual standard on an evaluation of both the short- and long-term health effects information), with the 24-hour standard being used to address more localized short-term peaks. A number of commenters, notably some among the groups opposing any revised PM

standards, appeared to have ignored this fundamental aspect of the proposal, judging by their assertions that the sole basis for EPA's proposed annual standards was two long-term exposure studies (Dockery et al., 1993; Pope et al. 1995). This is incorrect; as the proposal states, EPA based the proposed annual standard level on a wider range of short- and long-term exposure studies. Other commenters, including some environmental groups, reserved comment on this specific issue, but expressed concerns that the specific levels for both standards were not stringent enough, regardless of which standard is intended to be controlling. Issues regarding specific levels are discussed below in Unit II.F. of this preamble.

Some commenters, however, disagreed with the proposition that EPA's proposed approach would necessarily provide the most effective and efficient standards. In the view of some who opposed $PM_{2.5}$ standards, the likelihood that there are thresholds below which no effects occur means that a 24-hour standard would be more efficient than an annual standard. In this view, the reductions made on days that were below the threshold would provide no protection.[29] Some commenters also noted that while a majority of CASAC members favored both annual and 24-hour standards, more recommended 24-hour standards.

While the available epidemiological studies provide strong evidence suggesting that PM causes or contributes to health effects at levels below the current standards, EPA agrees, as stated previously, that uncertainties increase markedly at lower concentrations. Nevertheless, the level or even existence of population thresholds below which no effects occur cannot be reliably determined by an examination of the results from the available studies. Analyses have placed some limits, however, and EPA has considered hypothetical thresholds in its risk assessment. As noted in Unit II.A. of this preamble, even assuming an example threshold of 18 $\mu g/m^3$, the risk assessment (see Figure 2c; 61 FR 65653, December 13, 1996) finds that most of the annual aggregate risk associated with short-term exposures still results from the large number of days at lower to mid-range values above the mean. Given that neither the Criteria Document nor commenters have provided quantitative evidence regarding the likelihood of a threshold at levels much higher than the above example, EPA believes that the evidence provided in the risk assessment does not support the commenters' position. As noted above, EPA believes that most CASAC opinions on averaging time reflect panelists' judgments on the relative strength of the short-term exposure epidemiological studies, a judgment that EPA shares. Although most CASAC panel members did not offer an opinion on the use of short-term exposure studies in specifying annual standards, two panelists did support this notion. EPA therefore believes this approach is neither inconsistent with the underlying science nor discordant with the advice of CASAC.

Another concern was raised by some air pollution control officials who otherwise supported revised PM standards. These commenters state that, from an implementation perspective, it is often easier to design control strategies for single short-term events than for annual averages. Aside from whether this is a proper consideration in establishing NAAQS, the point in fact highlights one of the important strengths of an annual standard in addressing short-term risks associated with $PM_{2.5}$. As noted by the commenters, risk management for a short-term standard focuses on a characteristic ''design value'' episode responsible for peak concentrations. For PM, such peak values can be associated with single source contributions. Meteorology, relative source contributions, and resulting particle composition for that day may or may not be typical for the area or for the year. Yet the short-term exposure epidemiological results are largely drawn from studies that associated variations in area-wide effects with monitor(s) that gauged the variation in daily levels over the course of up to 8 years. The strength of the associations in these data is demonstrably in the numerous ''typical'' days in the upper to middle portion of the annual distribution, not on the peak days.[30] For these reasons, strategies that focus only on reducing peak days are less likely to achieve reduction of the mix and sources of urban and regional-scale PM pollution most strongly associated with health effects. Although designing control strategies to reduce annual levels may be more difficult than for 24-hour standards, the available short- and long-term epidemiological data suggest it is also likely to result in a greater reduction in area-wide population exposure and risk.

The Administrator concludes that the most effective and efficient approach to establishing $PM_{2.5}$ standards is to treat the annual standard as the generally controlling standard for lowering both short- and long-term $PM_{2.5}$ concentrations, while the 24-hour standard would serve to provide protection against days with high peak $PM_{2.5}$ concentrations, localized ''hot spots,'' and risks arising from seasonal emissions that would not be well controlled by a national annual standard. In reaching this view, the Administrator took into account the public comments and the factors discussed below in this unit.

(1) Based on one of the key observations from the quantitative risk assessment summarized above (see Figures 2a,b,c; 61 FR 65652-65653, December 13, 1996), the Administrator notes that much if not most of the aggregate annual risk associated with short-term exposures results from the large number of days during which the 24-hour average concentrations are in the low- to mid-range, below the peak 24-hour concentrations. As a result, lowering a wide range of ambient 24-hour $PM_{2.5}$ concentrations, as opposed to focusing on control of peak 24-hour concentrations, is the most effective and efficient way to reduce total population risk. Further, there is no evidence suggesting that risks associated with long-term exposures are likely to be disproportionately driven by peak 24-hour concentrations. Thus, an annual standard that controls an area's attainment status is likely to reduce aggregate risks associated with both short- and long-term exposures with more certainty than a 24-hour standard.

(2) The consistency and coherence of the health effects data base are, therefore, more directly related to the more frequently occurring PM exposures reflected in study period mean measures of air quality (e.g., the annual distributions of 24-hour PM concentrations), than to the potentially site-specific and/or otherwise infrequent PM exposures reflected in a limited number of peak 24-hour concentrations. More specifically, judgments about the quantitative consistency of the large number of short-term exposure studies

[29] A related comment criticized the risk assessment conclusion that peak 24-hour concentrations contribute much less to the total risk over a year as inconsistent with the experience in historic air pollution episodes. EPA disagrees. While the historic London episodes were quantitatively different from those assumed in the risk assessment, the record over 14 London winters indicates a continuum of effects down to the lowest levels. It is therefore likely that the cumulative increase in mortality calculated for all the days in the whole 14-year period would not be dominated by the more limited number of episode days.

[30] This point is buttressed by studies that have taken out a limited number of higher PM concentration days with little effect on the effects estimates or significance of the association (e.g., Schwartz et al., 1996; Pope and Dockery, 1992).

reporting associations with 24-hour concentrations arise from comparing the relative risk results per PM increment as derived from analyzing the associations across the entire duration of the studies. These studies typically spanned at least an annual time frame and the reported associations are most strongly influenced by the large number of days toward the middle of the distribution.

(3) An annual average measure of air quality is more stable over time than are 24-hour measures. Thus, a controlling annual standard is likely to result in the development of more consistent risk reduction strategies over time, since an area's attainment status will be less likely to change due solely to year-to-year variations in meteorological conditions that affect the formation of fine particles, than under a controlling 24-hour standard.

Under this policy approach, the annual $PM_{2.5}$ standard would serve in most areas as the target for control programs designed to be effective in lowering the broad distribution of $PM_{2.5}$ concentrations, thus protecting not only against long-term effects but also short-term effects as well. In combination with such an annual standard, the 24-hour $PM_{2.5}$ standard would be set so as to protect against the occurrence of peak 24-hour concentrations, particularly peak concentrations that present localized or seasonal exposures of concern in areas where the highest 24-hour-to-annual mean $PM_{2.5}$ ratios are appreciably above the national average.

E. Form of $PM_{2.5}$ Standards

1. *Annual standard.* As discussed in some detail during the last review of the PM NAAQS (see 49 FR 10408, March 20, 1984; 52 FR 24634, July 1, 1987) and in the December 13, 1996 proposal, the annual arithmetic mean form of the current annual PM_{10} standard (i.e., the annual arithmetic mean averaged over 3 years) is a relatively stable measure of air quality that reflects the total cumulative dose of PM to which an individual or population is exposed. Short-term peaks have an influence on the arithmetic mean that is proportional to their frequency, magnitude, and duration, and, thus, their contribution to cumulative exposure and risk. As a result, the annual arithmetic mean form of an annual standard provides protection across a wide range of the air quality distribution contributing to exposure and risk, in contrast to other forms, such as the geometric mean, that de-emphasize the effects of short-term peak concentrations.

While almost no commenters took specific issue with use of an annual arithmetic mean, a number of commenters disagreed with averaging over 3 years for both the annual and 24-hour standards because of their desire for quick action in the initial implementation of $PM_{2.5}$ controls. The Administrator recognizes the importance of promptly implementing appropriate control programs, but she does not believe that implementation start-up concerns are an adequate basis for adopting a form (e.g., a single year annual average) that would provide less stable risk reduction in the long-run. Therefore, the Administrator continues to concur with the Staff Paper recommendation, supported by CASAC, to use the annual arithmetic mean, averaged over 3 years, as the form for an annual $PM_{2.5}$ standard consistent with the current form of the annual PM_{10} standard. Nevertheless, EPA intends to address the concerns of those who commented that the 3-year form might prevent the public from being informed about the air quality status of their communities. As outlined in Unit II.H. of this preamble, EPA plans to issue revised Pollutant Standard Index criteria for $PM_{2.5}$, to ensure the public is informed promptly about air quality status.

The Staff Paper and some CASAC panel members also recommended that consideration be given to calculating the $PM_{2.5}$ annual arithmetic mean for an area by averaging the annual arithmetic means derived from multiple monitoring sites within a monitoring planning area. In proposing a calculation method for annual arithmetic averages that involves spatial averaging of monitoring data, the Administrator reasoned as follows:

(1) Many of the community-based epidemiological studies examined in this review used spatial averages, when multiple monitoring sites were available, to characterize area-wide PM exposure levels and the associated population health risk. In those studies that used only one monitoring location, the selected site was chosen to represent community-wide exposures, not the highest value likely to be experienced within the community. Thus, spatial averages are most directly related to the epidemiological studies used as the basis for the proposed revisions to the PM NAAQS.

(2) As a part of the overall policy approach discussed in Unit II.D. of this preamble, the annual $PM_{2.5}$ standard would be intended to reduce aggregate population risk from both long- and short-term exposures by lowering the broad distribution of $PM_{2.5}$ concentrations across the community. An annual standard based on spatially averaged concentrations would better reflect area-wide PM exposure levels than would a standard based on concentrations from a single monitor with the highest measured values.

(3) Under this policy approach, the 24-hour $PM_{2.5}$ standard would be intended to work in conjunction with a spatially averaged annual $PM_{2.5}$ standard by providing protection against peak 24-hour concentrations, localized ''hot spots,'' and higher $PM_{2.5}$ concentrations arising from seasonal emissions and meteorology that would not be as well controlled by an annual standard. Accordingly, the 24-hour $PM_{2.5}$ standard should be based on the single population-oriented monitoring site within the monitoring planning area with the highest measured values.

Based on these considerations, the Administrator proposed that the form of an annual $PM_{2.5}$ standard be expressed as the annual arithmetic mean, temporally averaged over 3 years and spatially averaged over all designated monitoring sites,[31] which, in conjunction with a 24-hour $PM_{2.5}$ standard, was intended to provide the most appropriate target for reducing area-wide population exposure to fine particle pollution. Recognizing the complexities that spatial averaging might introduce into risk management programs, in the proposal the Administrator also requested comment on the alternative of basing the annual standard for $PM_{2.5}$ solely on the single population-oriented monitor site within the monitoring planning area with the highest 3-year average annual mean.

The proposed approach to designating sites that are appropriate for spatial averaging was based on criteria and constraints contained in the proposed revision to the monitoring siting and network planning requirements in 40 CFR part 58. In proposing this approach, the Administrator noted concerns regarding the development and implementation of appropriate and effective criteria for the selection of sites and designations of areas for spatial averaging.

A number of commenters who otherwise favored setting $PM_{2.5}$ standards objected to the concept of population-oriented monitors and expressed the view that any monitor regardless of where it was sited should be eligible for comparison to the annual $PM_{2.5}$ standard. They further maintained that the proposed provisions for spatial averaging would fail to provide adequate health protection because

[31] The notice of proposed revisions to 40 CFR part 58 recognized that a single appropriately sited monitor could suffice for an area in place of an average of multiple monitors.

''clean areas'' and ''dirty areas'' would be averaged together. Some commenters expressed concern that the proposed constraints on spatial average would not be sufficient to prevent use of such averaging to avoid pollution abatement. Others may not have fully understood the implications of the specific constraints and siting requirements discussed in the proposed revisions to 40 CFR part 58, which were intended to ensure that the population-oriented monitors used for the annual standard were actually reflective of community-wide exposures and that the spatial averages did not include non-representative monitored values from either ''clean areas'' or ''dirty areas.''[32] In order to clarify the intent that the spatially averaged annual standard protect those in smaller communities, as well as those in larger population centers, the final revisions to 40 CFR part 58 adopt the term ''community-oriented'' monitors.

Other commenters, who supported $PM_{2.5}$ annual standards, endorsed the concept of spatial averaging as being more reflective of the air quality data used in the underlying health studies and because there is general uniformity of fine particle concentrations across an area. Opponents of the $PM_{2.5}$ standards expressed contingent support for spatial averaging in concept, again citing the linkage to the underlying health studies. Indeed, they advocated the extension of spatial averaging to the daily form of the standard, and/or recommended less constrained spatial averaging to allow for averaging across entire metropolitan areas.

The Administrator, of course, shares commenters' concerns that the form of the standards, in conjunction with other components of the standards, must protect public health adequately against risks associated with PM. It was for this reason that EPA proposed a policy approach providing for greatest overall risk reduction for all citizens in the community from exposures to the mix of urban and regional scale PM pollution most strongly associated with health effects. In specifically considering whether to allow for the use of spatial averaging, the Administrator placed great weight on consistency with the underlying body of health effects evidence. The Administrator is mindful that some community studies relied inherently on exposure and effects estimates that reflect comparatively broad spatial scales, as highlighted by those commenters desiring to extend permissible averaging; however, this type of exposure characterization may not be appropriate for all circumstances and might leave some areas without adequate protection.[33]

For these reasons, the 40 CFR part 58 proposal package contained criteria and constraints on spatial averaging. These criteria and constraints were intended to ensure that spatial averaging would not result in inequities in the level of protection provided by the PM standards. The Administrator again recognizes that either a single properly sited community-oriented monitor, or an average of more than one such monitors, are both appropriate indices of area-wide population exposures. Both are consistent with monitoring approaches used in community epidemiological studies upon which the standards are based. On the other hand, comparing the annual $PM_{2.5}$ standard to the maximum concentrations at a site that is not representative of community exposures, as some have suggested, would be inconsistent with the Administrator's goal of using the annual standard to reduce urban and regional scale exposures and risks. Further, the Administrator believes that the criteria and, siting requirements contained in 40 CFR part 58, provide adequate safeguards against inappropriate application of spatial averaging. Therefore, the Administrator continues to believe that an annual $PM_{2.5}$ standard reflective of area-wide exposures, in conjunction with a 24-hour standard designed to provide adequate protection against localized peak or seasonal $PM_{2.5}$ levels, reflects the most appropriate approach for public health against the effects of PM reported in the scientific literature.[34]

The majority of comments from States stressed the need for flexibility in specifying network designs and spatial averaging, given that the nature and sources of particle pollution vary from one area to another. One State agency specifically requested the flexibility to choose whether to use a single community-oriented monitor or a spatial average of several of such monitors, arguing that it is appropriate to provide this flexibility as $PM_{2.5}$ monitoring networks evolve and to address the diversity of local conditions.

As a result of EPA's evaluation of these comments, the requirements of 40 CFR part 50, Appendix K, and 40 CFR part 58 have been revised to clarify that the implementing agencies have the flexibility to compare the annual $PM_{2.5}$ standard either to the measured value at a single representative community-oriented monitoring site, or to the value resulting from an average of community-oriented monitoring sites that meet the revised criteria and constraints enumerated in the 40 CFR part 58 final rule.

In the Administrator's view, the final criteria and siting requirements contained in 40 CFR part 58 and in the new 40 CFR part 50, Appendix N, address the concerns raised by these commenters about the protection afforded by the form of the annual standard. Therefore, the Administrator continues to believe that the form of a $PM_{2.5}$ annual standard should be expressed as an annual arithmetic mean, averaged over 3 years, from single or multiple community-oriented monitors, in accordance with 40 CFR part 50, Appendix N and 40 CFR part 58. In her judgment, an annual standard expressed in this manner and set at an appropriate level, in conjunction with a 24-hour $PM_{2.5}$ standard, will adequately protect public health.

2. *24-hour standard.* The current 24-hour PM_{10} standard is expressed in a ''1-expected-exceedance'' form. That is, the standard is formulated on the basis of the expected number of days per year (averaged over 3 years) on which the level of the standard will be exceeded. The test for determining attainment of the current 24-hour standard is presented in Appendix K to 40 CFR part 50.

As discussed in the proposal, since promulgation of the current 24-hour PM_{10} standard in 1987, a number of concerns have been raised about the 1-

[32] The 40 CFR part 58 proposed rule identified the proposed criteria for monitors to be averaged; namely, monitors must be properly sited to reflect population-orientation, primarily influenced by similar sources, and within +/-20 percent of the average levels and a specific degree of correlation (or meet a ''homogeneity'' constraint). Additional criteria include demonstrations that the monitors to be averaged are influenced primarily by similar sources (e.g., to prevent the placement of monitors upwind in unrepresentative locations), EPA oversight of the monitoring program which includes regular review and approval of the State PM monitoring network design, and other criteria to ensure proper monitor siting. The final rule includes the addition of provisions that the State PM monitoring network design be available for public inspection.

[33] Daily mortality studies generally use urban or metro-areawide effects statistics in conjunction with single or multiple monitors that index day-to-day pollution changes across the area. Ito et al. (1995) found that spatial averages from multiple PM monitors in Chicago were better correlated with daily mortality than were most single monitors, but that single monitors were also associated. A number of morbidity studies (e.g., Schwartz et al., 1994; Neas et al., 1995; Raizenne et al.; 1996) used community scale monitors and effects information from a defined group of subjects from the community, who were more closely represented by the monitor.

[34] Because the 24-hour standard is designed to address localized peaks, it would be inappropriate to extend spatial averaging forms to this standard.

expected-exceedance form. These include, in particular, the year-to-year stability of the number of exceedances, the stability of the attainment status of an area, and the complex data handling conventions specified in 40 CFR part 50, Appendix K, including the procedures for making adjustments for missing data and less-than-every-day monitoring.

In light of these concerns, the Staff Paper and several CASAC panel members (Wolff, 1996b) recommended that consideration be given to adoption of a more stable and robust form for 24-hour standards. In considering this recommendation for the proposal, the Administrator noted that the use of a concentration-based percentile form would have several advantages over the current 1-expected-exceedance form:

(1) Such a concentration-based form would be more directly related to the ambient PM concentrations that are associated with health effects. Given that there is a continuum of effects associated with exposures to varying levels of PM, the extent to which public health is affected by exposure to ambient PM is related to the actual magnitude of the concentration, not just whether the concentration is above a specified level. With an exceedance-based form, days on which the ambient concentration is well above the level of the standard are given equal weight to those days on which the concentration is just above the standard (i.e., each day is counted as one exceedance), even though the public health impact on the 2 days is significantly different. With a concentration-based form, days on which higher concentrations occur would weigh proportionally more than days with lower concentrations for the design value, since the actual concentrations would be used directly in determining whether the standard is attained.

(2) A concentration-based percentile form would also compensate for missing data and less-than-every-day monitoring, thereby reducing or eliminating the need for complex data handling procedures in the 40 CFR part 50, Appendix K test for attainment. As a result, an area's attainment status would be based directly on monitoring data rather than on a calculated value adjusted for missing data or less-than-every-day monitoring.

(3) Further, a concentration-based form, averaged over 3 years, would also have greater stability than the expected exceedance form and, thus, would facilitate the development of more stable implementation programs by the States.

The proposal discussed various specific percentile values for such a form (e.g., 90th to 99th percentiles), taking into account two factors. First, the 24-hour $PM_{2.5}$ standard is intended to supplement the annual $PM_{2.5}$ standard by providing additional protection against extremely high peak days, localized ''hot spots,'' and risks arising from seasonal emissions. Second, given an appropriate level of health protection, the form of the 24-hour $PM_{2.5}$ standard should provide an appropriate degree of increased stability relative to the current form. The Administrator noted in the proposal that a more stable statistic would reduce the impact of a single high exposure event that may be due to unusual meteorological conditions alone, and thus would provide a more stable basis upon which to design effective control programs.

With these purposes in mind, the Administrator observed in the proposal that while a percentile value such as the 90th or 95th would provide substantially increased stability when compared to a more extreme air quality statistic (e.g., the current 1-expected-exceedance form), it would likely not serve as an effective supplement to the annual standard, because it would allow a large number of days with peak $PM_{2.5}$ concentrations above the standard level. For example, in a 365-day data base, the 90th and 95th percentiles would equal the 37th and 19th highest 24-hour concentrations, respectively. On the other hand, a percentile value selected much closer to the tail of the air quality distribution (e.g. a 99th or greater percentile) would not likely provide significantly more health protection or significantly increased stability as compared to a 1-exceedance form. In balancing these issues in the proposal, the Administrator ultimately proposed a 98th percentile value form of the standard.

Some commenters maintained that EPA should retain the current 1-expected-exceedance form for the 24-hour $PM_{2.5}$ standard to limit the number of days per year that the standard is exceeded. These commenters apparently gave little weight to EPA's rationale that a concentration-based form is more directly related to ambient PM concentrations that are associated with health effects because it takes into account the magnitude of PM concentrations, not just whether the concentrations are above a specific level. These commenters also discounted the other advantages of a concentration-based percentile form outlined above in this unit. A number of other commenters supported the concentration-based percentile form for the reasons outlined in the proposal but, as discussed below in this unit, argued for alternative percentile values that were higher or lower than the proposed 98th percentile value.

EPA continues to believe that a concentration-based percentile form is more reflective of the health risk posed by elevated PM concentrations, because it gives proportionally greater weight to days when concentrations are well above the level of the standard than to days when the concentrations are just above the standard. This factor, coupled with the other advantages outlined above in this unit, leads EPA to conclude that a concentration-based percentile form will provide for more effective health protection than a 1-expected-exceedance form.

Some commenters supporting a single exceedance form or a more restrictive concentration-based percentile form (e.g. a 99th percentile) expressed concern that the proposed 98th percentile form could allow too many high concentration excursions, and thus fail to provide adequate protection against seasonal emissions problems or localized peaks. In particular, some commenters expressed concerns that in areas with strongly seasonal emissions, such as western areas with winter inversions, over a three year period an area could experience several excursions in which levels could reach as high as 250 $\mu g/m^3$ and still comply with both the annual and daily standards if the remainder of the days had low levels (e.g., 10 $\mu g/m^3$). Although this combination of events is theoretically possible, EPA believes it is unlikely. Moreover, if such episodic events did occur, the Act provides for emergency State or Federal action to address them.[35] In view of the limits on truely episodic peak concentrations, EPA believes that an appropriately selected 24-hour standard with a concentration-based 98th percentile form can provide a stable and adequately protective supplement to the annual standard in areas with periodic peak concentrations.

Other commenters who were also concerned with monitoring requirements associated with spatial averaging in the annual standard, argued that a 98th percentile form, coupled with the proposed monitoring requirements that would limit

[35] See sections 303, 110(a)(2)(y); 40 CFR part 51. EPA intends to establish a significant harm level for $PM_{2.5}$ and associated guidance so States can develop appropriate emergency episode plans. The significant harm and episode criteria will be included in forthcoming proposed revisions to 40 CFR part 51 and 40 CFR part 58 implementation guidance. In the interim, existing PM_{10} emergency episode plans should be triggered by events of this magnitude.

compliance monitors for the 24-hour standard to population-oriented sites, would not protect people residing in or near localized ''hot spots'' in some areas.[36] The Administrator believes that the siting requirements as proposed and finalized in 40 CFR part 58 for population-oriented sites will provide adequate safeguards for such residential areas.

Other commenters, who otherwise opposed setting $PM_{2.5}$ standards, recommended that alternative lower percentiles (e.g., 95th percentiles) be used, if EPA proceeds to set such standards. As discussed above in this unit, however, EPA continues to hold the view that a 90th to 95th percentile form would not provide an adequate limit against periodic peak values in areas with low annual values and periodic high seasonal or source-oriented peaks.

After carefully assessing the comments received, the Administrator is persuaded that the adoption of a 98th percentile form for the 24-hour $PM_{2.5}$ standard measured at each population-oriented monitoring site in an area would provide an effective supplement to the annual $PM_{2.5}$ standard. This form will provide adequate protection against 24-hour peak $PM_{2.5}$ levels in locations dominated by single point sources, as well as in areas dominated by seasonal emissions. The Administrator also believes that a 98th percentile form, with more frequent sampling and averaged over 3 years, will provide increased stability and robustness as recommended by several members of the CASAC panel. For these reasons, the Administrator has decided to adopt the 98th percentile form for the final $PM_{2.5}$ 24-hour standard. The 24-hour $PM_{2.5}$ standard would be attained when the 3-year average of the 98th percentile of 24-hour concentrations at each populated oriented monitor within an area is less than or equal to the level of the standard. Further details regarding the interpretation of the form, as well as associated calculations and other data handling conventions are specified in the new 40 CFR part 50, Appendix N.

F. Levels for the Annual and 24-Hour $PM_{2.5}$ Standards

As discussed in Unit II.D. of this preamble, the Administrator believes that an annual $PM_{2.5}$ standard can provide the requisite reduction in risk associated with both annual and 24-hour averaging times in most areas of the United States. Under this approach, the 24-hour standard would be intended to provide supplemental protection against extreme peak fine particle levels that may occur in some localized situations or in areas with distinct variations in seasonal fine particle levels. In reaching judgments as to appropriate levels to propose for both the annual and 24-hour $PM_{2.5}$ standards, the Administrator has considered the combined protection afforded by both the annual and 24-hour standards, taking into account the forms discussed in Unit II.E. of this preamble.

With this approach in mind, the Administrator has considered the available health effects evidence and related air quality information presented in the Criteria Document and summarized in chapters IV--VII of the Staff Paper, which provides the basis for decisions on standard levels that would reduce risk sufficiently to protect public health with an adequate margin of safety, recognizing that such standards will not be risk-free. In so doing, the Administrator has considered both the strengths and the limitations of the available evidence and information, as well as alternative interpretations of the scientific evidence advanced by various CASAC panel members (Wolff, 1996b; Lippmann et al., 1996) and public commenters, arising primarily from the inherent uncertainties and limitations in the health effects studies.

Beyond those factors, but clearly related to them, a range of views have been expressed by CASAC panel members and the public as to the appropriate policy response to the available health effects evidence and related air quality information. Toward one end of the spectrum, the view has been expressed that only a very limited policy response is appropriate in light of the many key uncertainties and unanswered questions that, taken together, call into question the fundamental issue of causality in the reported associations between ambient levels of $PM_{2.5}$ and mortality and other serious health effects. Toward the other end, the view has been expressed that the consistency and coherence of the epidemiological evidence should be interpreted as demonstrating causality in the relationships between $PM_{2.5}$ and health endpoints that are clearly adverse, and that uncertainties in the underlying health effects information should be treated, regardless of their nature, as warranting a maximally precautionary policy response. A third view would suggest an alternative policy response, taking into account not only the consistency and coherence of the health effects evidence, but also the recognition of key uncertainties and unanswered questions that increasingly call into question the likelihood of PM-related effects as $PM_{2.5}$ concentrations decrease below the mean values in areas where effects have been observed and/or as such concentrations approach background levels.

Reflecting these divergent views, both of the science itself and of how the science should be used in making policy decisions on proposed standards, the Administrator considered three alternative approaches to selecting appropriate standard levels, as described in the proposal, ultimately deciding to propose standards based on a balanced view of the strengths and uncertainties of the scientific information that reflects the intermediate approach.

Judging by the public comments received, EPA accurately reflected the bases for divergent views. A substantial body of public comments supported revising the PM standards by adding $PM_{2.5}$ standards with levels at least as stringent as those proposed by the Administrator. In general, however, comments on levels for $PM_{2.5}$ standards revealed a strong dichotomy between those who recommended even stronger standards than proposed, and those who counseled against revising the standards at all. As noted above in this unit, many in this latter group made contingent recommendations with respect to the levels and other aspects of $PM_{2.5}$ standards, if the Administrator concluded that any revisions were appropriate.

This latter group of ''contingent'' commenters recommended levels well above those proposed by the Administrator. These commenters placed great weight on factors outlined in Units II.B. and II.C. of this preamble that led them to oppose any revisions to the PM standards, including the uncertainties and limitations in the available health effects studies considered individually, such as the possible existence of effects thresholds and unanswered questions regarding the causal agent(s) responsible for the reported health effects. Further, they emphasized the limited amount of research currently available that has measured $PM_{2.5}$ directly. A substantial group recommended that $PM_{2.5}$ standards be selected so as to be equivalent or close in stringency to the current PM_{10} standards, and cited the opinions of some CASAC PM panel members as support. Some of these commenters provided supplemental analyses of air quality data, arguing that they demonstrate that ''equivalent'' standards would be at $PM_{2.5}$ levels as

[36] The 40 CFR part 58 monitoring rule proposed to limit sites that would be eligible for comparisons to the 24-hour standard to population-oriented monitoring sites.

high as approximately 95 μg/m^3 24-hour average and 27 μg/m^3 annual average.

Having evaluated these comments, the Administrator rejects both their underlying rationale and the specific recommendations for $PM_{2.5}$ standard levels that result in similar or only marginally more protection than that afforded by the current PM_{10} standards. Aside from technical problems in the commenters' supporting analyses on the issue of defining ''equivalent'' standards,[37] the Administrator finds this approach inconsistent with her conclusions regarding the adequacy of the current standards and the need to provide additional protection as articulated in Unit II.B. of this preamble. The Administrator believes that, despite well recognized uncertainties, the consistency and coherence of the epidemiological evidence and the seriousness of the health effects require a more protective response than provided by ''equivalence'' or a marginal strengthening of the standards. Moreover, EPA believes that the standard levels should be based on the most recent assessment of the scientific criteria for PM, not on applying uncertain ratios to standard decisions based on much more limited evidence in 1987. The Administrator also rejects the premise of some[38] who suggest that adopting a standard that prompts little or no additional control would cause no delay in risk reduction as compared to conducting monitoring and research now and setting a more stringent standard after the next review. These comments do not consider the realities of implementing air quality standards, which ensure that such an approach would add several years to the risk reduction process. Thus, aside from her obligations under the statute,[39] the Administrator believes that the most prudent and appropriate course is to establish appropriately protective standards now that put into motion monitoring and strategy development programs, while at the same time pursuing an expanded research program to improve implementation and to inform the next periodic review of the criteria and standards.

In sharp contrast to the commenters discussed immediately above, a number of other commenters strongly supported standard levels more stringent than those proposed by EPA. These commenters supported EPA's conclusions regarding the epidemiological studies, but would place much less weight on uncertainties related to the concentration-response relationships for $PM_{2.5}$ as a surrogate for PM and the relative importance of various PM components. Based on their evaluation of the information, and citing the support of some CASAC panel members, these commenters variously recommended 24-hour $PM_{2.5}$ standards as low as 18 to 20 μg/m^3 and annual standards of 10 to 12 μg/m^3.[40]

EPA notes that setting such standards would result in commensurate reductions in health risks only if, in fact, there is a continuum of health risks down to the lower end of the ranges of air quality observed in the key epidemiological studies, and only if the reported associations are, in fact, causally related to $PM_{2.5}$ at the lowest concentrations measured. Setting standards at low levels where the possibility of effects thresholds is greater, and where there is greater potential that other elements in the air pollution mix (or some subset of particles within the fine fraction) become more responsible for (or modify) the effects being causally attributed to $PM_{2.5}$, might result in regulatory programs that go beyond those that are needed to effectively reduce risks to public health. While placing substantial weight on the results of the key health studies in the higher range of concentrations observed, EPA is persuaded that the inherent scientific uncertainties are too great to support standards based on the lowest concentrations measured in such studies, which approach the maximum range of $PM_{2.5}$ values estimated for short-term background conditions.

Having considered the comments reflecting the two contrasting views summarized above in this unit, the Administrator concludes that the approach she set forth in the proposal is the most appropriate for selecting levels for annual and 24-hour $PM_{2.5}$ standards. This approach focuses primarily on standard levels designed to limit annual $PM_{2.5}$ concentrations to somewhat below those where the body of epidemiological evidence is most consistent and coherent, in recognition of both the strengths and the limitations of the full range of scientific and technical information on the health effects of PM, as well as associated uncertainties, as interpreted by the Criteria Document, Staff Paper, and CASAC. The Administrator believes that this approach appropriately reflects the weight of the evidence as a whole.

In identifying $PM_{2.5}$ standard levels consistent with this overall approach, the Administrator has placed greatest weight on those epidemiological studies reporting associations between health effects and direct measures of fine particles, most notably those recent studies conducted in North America (summarized in Tables V-12 and V-13 of the Staff Paper).[41] Key considerations and study results upon which this approach is based are presented as follows.

As previously discussed, the Administrator has concluded that it is appropriate to select the level of the annual standard so as to protect against the range of effects associated with both short- and long-term exposures to PM,

[37] Nationwide $PM_{2.5}$ estimates have been derived from the current PM air quality data base, but reflect a significant degree of uncertainty due to the highly variable relationship between $PM_{2.5}$ and PM_{10} air quality values across locations and seasons (Fitz-Simons et al., 1996). The American Iron and Steel Institute (AISI) submitted a useful data base (Cooper Associates, 1997) on $PM_{2.5}/PM_{10}$ relationships that examines both these predictions and the issue of equivalence. An EPA examination of this material, which found some problems with the analysis and with commenters' conclusions that appear inconsistent with the Cooper report, is included in the Response to Comments.

[38] Some commenters suggest that CASAC and EPA support for $PM_{2.5}$ standards is based on the need to stimulate additional monitoring and research. While the Administrator agrees that the additional monitoring and research that would accompany establishment of equivalent or marginally tighter $PM_{2.5}$ standards are very important goals, they do not form an adequate rationale for establishing air quality standards.

[39] As stated previously, section 109(d) of the Act requires that, after reviewing the existing criteria and standards for PM, the Administrator make such revisions in the standards and promulgate such new standards as are appropriate under section 109(b) of the Act.

[40] This range of levels for a 24-hour $PM_{2.5}$ standard is close to the lower bound levels recommended by four CASAC panel members (20 μg/m^3); no member supported an annual $PM_{2.5}$ standard as low as 10 to 12 μg/m^3.

[41] Some confusion is apparent in comments regarding the basis on which the Administrator selected levels for the proposed $PM_{2.5}$ standards, with some commenters suggesting two or at most three studies were used, and others suggesting that EPA relied extensively on uncertain conversion factors to estimate levels for the standards. These comments are in error. To clarify, as stated in the proposal, the Administrator is basing her decision to revise the standards on the full range of PM health effects studies summarized in the Criteria Document and Staff Paper, but in selecting specific levels for $PM_{2.5}$ standards, is relying chiefly on U.S. and Canadian studies, listed in Tables V-12 and V-13 of the Staff Paper, that measured fine PM levels. To ease identification and use of these key studies, the short-term exposure studies and key PM air quality statistics are cited in Koman (1996) and all long-term exposure studies are cited in this preamble. The referenced memorandum (Koman, 1996) has been updated (Koman, 1997) to clarify key aspects of the studies cited and relevant air quality statistics. In accordance with EPA and CASAC views on the relative strength of these studies, greater weight is placed on short-term exposure studies than on long-term exposure studies. Where studies found statistically significant associations with $PM_{2.5}$ components (e.g., sulfates and/or acids, in Thurston et al., 1994; Dockery et al., 1996), the corresponding $PM_{2.5}$ or $PM_{2.1}$ values from the study are cited. No conversions were made from the original measurements used in these studies.

with the 24-hour standard level selected to provide supplemental protection against peak concentrations that might occur over limited areas and/or for limited time periods. In selecting the level for the annual standard, therefore, the Administrator has considered both short- and long-term exposure studies.

In accordance with EPA staff and CASAC views on the relative strengths of the epidemiological studies, the Administrator has placed greater emphasis on the short-term exposure studies in selecting the level of the annual standard. The approach she took to this issue consisted of determining a provisional level based on the short-term exposure studies, and then determining whether the long-term exposure studies are consistent with that level or, instead, suggest the need for a lower level. The effects estimates from the short-term exposure studies (in Table V-12 of the Staff Paper) are based on analyses of daily $PM_{2.5}$ concentrations that occurred over the course of the study period. While effects may occur over the full range of concentrations observed in the studies, consistent with the discussion of this issue in Unit II.D. of this preamble, the strongest evidence for short-term $PM_{2.5}$ effects occurs at concentrations near the long-term (e.g., annual) average. More specifically, the strength of the evidence of effects increases for concentrations that are at or above the long-term (e.g., annual) mean levels reported for these studies.[42] Given the serious nature of the potential effects, the Administrator believes it is both prudent and appropriate to select a level for an annual standard at or below such concentrations. An examination of the long-term means from the combined six city analyses of daily mortality (Schwartz et al., 1996a) and morbidity (Schwartz et al., 1994), together with those from studies in individual cities for which statistically significant PM-effects associations are reported (from Table V-12 in the Staff Paper), finds mean concentrations ranging from about 16 to about 21 $\mu g/m^3$ (Koman, 1996; 1997). In addition, the mean concentrations in cities where short-term exposure associations are characterized in the Criteria Document as nearly statistically significant (U.S. EPA, 1996a, p. 13-40) range from about 11 $\mu g/m^3$ to 30 $\mu g/m^3$. Taken together, and placing greatest weight on those studies that were clearly statistically significant, this evidence suggests that an annual standard level of 15 $\mu g/m^3$ is appropriate to reduce the risk of effects from short-term exposure to fine particles.

Before reaching a final conclusion, the Administrator also examined this level in light of the effects reported in epidemiological studies of long-term exposures to fine particles (Table V-13 in the Staff Paper), which may reflect the accumulation of daily effects over time as well as potential effects uniquely associated with long-term exposures. Even though subject to additional uncertainties, the long-term exposure studies provide important insights with respect to the overall protection afforded by an annual standard. These studies were examined for general consistency and support for the levels derived from the short-term exposure studies, and to determine whether they provide evidence that a more stringent level is needed.

The most direct comparison with the daily fine particle mortality studies is provided by two long-term prospective cohort studies (Dockery et al., 1993; Pope et al., 1995). The annual mean $PM_{2.5}$ concentration for the multiple cities included in these studies (6 and 50 cities, respectively) was 18 $\mu g/m^3$ (Dockery et al., 1993), and about 21-22 $\mu g/m^3$ for the larger Pope et al. (1995) study.[43] The Staff Paper assessment of the concentration-response results from Dockery et al. (1993) concluded that the evidence for increased risk was more apparent at annual concentrations at or above 15 $\mu g/m^3$ (Table E-3; U.S. EPA; 1996b).[44] EPA notes that the estimated mean values for most of the cities in Pope et al. (1995) are above 15 $\mu g/m^3$. As noted in the Staff Paper and the Criteria Document, the estimated magnitude of effects in both long-term exposure mortality studies may be related to higher historical concentrations than the affected communities experienced during the time period of the studies; this consideration suggests that a level of 15 $\mu g/m^3$ would incorporate a margin of safety. An examination of morbidity effects and long-term exposures is provided by the recent ''24 city'' studies, which found that reduced lung function and increased respiratory symptoms in children followed the gradient in annual mean concentrations of fine particles and/or acid-sulfate components of fine particles (Raizenne et al., 1996; Dockery et al., 1996). The results indicate a greater likelihood of effects at annual mean $PM_{2.1}$ levels above about 15 $\mu g/m^3$ (U.S. EPA, 1996b; Figure V-7). In the judgment of the Administrator, these studies are consistent with a standard level of 15 $\mu g/m^3$. While they provide some suggestion of risks extending to lower concentrations, they do not provide a sufficient basis for establishing a lower annual standard level.

Taking the epidemiological studies of both short- and long-term exposures together, the Administrator believes the concordance of evidence for PM effects and associated levels provides clear support for an annual $PM_{2.5}$ standard level of 15 $\mu g/m^3$. This level is below the range of annual data most strongly associated with both short- and long-term exposure effects, and because even small changes in annual means in this concentration range can make significant differences in overall risk reduction and total population exposures, the Administrator believes it will provide an adequate margin of safety against the effects observed in these epidemiological studies. Moreover, the means in areas where $PM_{2.5}$ concentrations were statistically significantly associated with daily mortality (about 16 to 21 $\mu g/m^3$) reflect a 7 to 9-year average; thus, the use of a 3-year mean will provide additional protection. Although the possibility of effects at lower annual concentrations cannot be excluded, the evidence for that possibility is highly uncertain and, as previously discussed, the likelihood of significant health risk, if any, becomes smaller as concentrations approach the lower end of the range of air quality observed in the key epidemiological studies and/or background levels.

The final annual standard will provide substantial protection against short-term as well as long-term exposures to particles. Nevertheless, for the reasons specified above, a spatially averaged annual standard cannot be expected to offer an adequate margin of safety against the effects of all potential short-term exposures in areas with strong local or seasonal sources. The

[42] As discussed in the proposal and Appendix E of the Staff Paper (U.S. EPA, 1996b, p. E-4), there is generally greatest statistical confidence in observed associations for levels at and above the mean concentration.

[43] Based on a public comment, EPA found that the mean of 18 $\mu g/m^3$ in Pope et al. (1995) reported in the Criteria Document and elsewhere was actually the mean of median values. Based on typical air quality relationships, the conventional arithmetic mean would be approximately 21 to 22 $\mu g/m^3$ (Freas, 1997). The lowest median concentration measured in this study (9 $\mu g/m^3$), which was relied upon by some commenters as a basis for annual standards of 10 $\mu g/m^3$, is about 11 to 12 $\mu g/m^3$ as an arithmetic mean.

[44] Based on public comments and a further evaluation of the underlying study, EPA concludes that the comparable assessment of the concentration-response function summarized in Table E-3 for Pope et al. (1995) is not appropriate, because it was based on a supplemental ''ecologic'' comparison for these cities and not on the far more reliable prospective-cohort analysis that was the main focus of the paper.

broad-based community studies considered in this review generally could not evaluate such peak exposure conditions directly. Given the public health purposes of the 24-hour standard, the Administrator believes it should be set at a level that generally supplements the control afforded by an annual standard and proposed an approach based on providing a reasonable degree of protection against the peak levels observed or expected in communities where health effects have been associated with daily levels of fine particles.

For the reasons specified in the previous unit, the Administrator has decided to use a 98th percentile concentration-based form of the standard. As noted in the proposal, the 98th percentile 24-hour $PM_{2.5}$ concentrations in cities with statistically significant or nearly significant short-term fine particle exposure-effects associations ranged from 34 μg/m³ to as high as 90 μg/m³ (Koman, 1996, 1997). Based on an examination of these results, EPA originally proposed a level for the 24-hour standard of 50 μg/m³, and solicited comments on higher and lower alternative levels.

In considering comments on alternative levels for the purpose of making a final decision on the 24-hour standard, the Administrator recognizes the significant uncertainties in identifying the extent of the incremental risk associated with single peak exposures to $PM_{2.5}$ in areas where the annual standard is met. Clearly, the risks associated with the 98th percentile air quality data used in the selecting the proposed level are from the same study cities that experienced long-term levels at varying amounts above that selected for the annual standard. It is unclear what risks might have been associated with such peak levels had the long-term averages in these areas been below that selected for the annual standard. Regardless of this uncertainty, it is clear that reducing the annual concentrations in such areas to that of the annual standard would reduce the risk associated with peak days, whatever the magnitude, as well as that associated with the far more numerous days with concentrations near the annual average. Given these uncertainties and the significant degree of protection afforded by the annual standard, the Administrator is persuaded that it is appropriate to adopt a different approach for selecting the levels of the 24-hour standard than the one proposed.

In making a final decision on an appropriate level for the 24-hour standard, the Administrator considered several key factors: the significant protection afforded against short-term exposures by the annual $PM_{2.5}$ standard; the role of the 24-hour standard in providing supplemental protection against peak exposures not addressed by the annual standard; the air quality and effects information in the studies cited above; the uncertainties in the risks associated with infrequent and isolated peak exposures in areas that meet the annual standard; the range of levels recommended by EPA staff and CASAC panel members; and the extensive public comment on the alternative levels proposed, which ranged between 20 and 65 μg/m³. Because of the approach of establishing the annual standard as the controlling standard, and, in particular, the decision to set the level at the lower end of the annual range, there is no need to consider levels in the lower portion of the 24-hour range below the level proposed. Therefore, the Administrator focused on evaluating the margin of safety associated with levels between 50 and 65 μg/m³.

As has been discussed in previous units, the extent of total risk over the course of a year associated solely with a limited number of peak exposures is uncertain, but it is considerably smaller than that associated with the entire air quality distribution. Further, the risk associated with infrequent peak 24-hour exposures in otherwise clean areas is not well enough understood at this time to provide a basis for selecting the more restrictive levels in the range of 50 to 65 μg/m³. On the other hand, it is clear that any standard level within this range would provide some margin of safety. Taking into account the factors outlined above, the Administrator has concluded that a 24-hour standard at the level of 65 μg/m³ would provide an effective limit in the role as a supplement to the annual standard. This level is at the upper end of the range recommended by staff and most CASAC panel members, and below the levels suggested by some CASAC panel members and by a number of public commenters. Although this level is not risk free, the Administrator believes that it would provide an appropriate degree of additional protection over that provided by the annual $PM_{2.5}$ standard. Accordingly, after weighing these factors in light of the scientific uncertainties, the Administrator believes that a 98th percentile 24-hour $PM_{2.5}$ standard of 65 μg/m³ would provide an adequate margin of safety against infrequent or isolated peak concentrations that could occur in areas that attain the annual standard of 15 μg/m³.

In the Administrator's judgment, the factors discussed above provide ample reason to believe that both annual and 24-hour $PM_{2.5}$ standards are appropriate to protect public health from adverse health effects associated with short- and long-term exposures to ambient fine particles. Further, she believes these factors provide a clear basis for judging that an annual $PM_{2.5}$ standard set at 15 μg/m³, in combination with a 24-hour standard set at 65 μg/m³, will protect public health with an adequate margin of safety.

G. Conclusions Regarding the Current PM_{10} Standards

1. *Averaging time and form.* In conjunction with $PM_{2.5}$ standards, the new function of PM_{10} standard(s) is to protect against potential effects associated with coarse fraction particles in the size range of 2.5 to 10 μm. Coarse fraction particles are plausibly associated with certain effects from both long- and short-term exposures (EPA 1996a,b). Based on qualitative considerations, deposition of coarse fraction particles in the respiratory system could be expected to aggravate effects in individuals with asthma. The Criteria Document and Staff Paper found support for this expectation in limited epidemiological evidence on the effects of coarse fraction particles, suggesting that aggravation of asthma and respiratory infections and symptoms may be associated with daily or episodic increases in PM_{10} that are dominated by coarse fraction particles. The potential build-up of insoluble coarse fraction particles in the lung after long-term exposures to high levels should also be considered.

Based on assessments of the available information in the Criteria Document and Staff Paper, both the staff and CASAC recommended retention of an annual PM_{10} standard. The staff, with CASAC concurrence, recommended retention of the current annual arithmetic mean form of the standard, which is the same form being adopted for the annual $PM_{2.5}$ standard. As noted in the staff assessment, the current annual PM_{10} standard offers substantial protection against the effects of both long- and short-term exposure to coarse fraction particles. Public comment was nearly unanimous in recommending retention of this standard. The Administrator therefore has decided to continue a long-term PM_{10} standard as an annual arithmetic mean, averaged over 3 years.

The staff and CASAC also recommended that consideration be

given to retention of a 24-hour standard to provide additional protection against potential effects of short-term exposures to coarse fraction particles. The staff, with CASAC concurrence, also recommended that if a 24-hour standard is retained, the form of the standard should be revised to provide a more robust target for coarse fraction particle controls. The Administrator originally proposed a 98th percentile form for the 24-hour PM_{10} standard based primarily on the reasons outlined above in this unit regarding the proposed form of the 24-hour $PM_{2.5}$ standard.

The EPA received few comments supporting elimination of the 24-hour PM_{10} standard. The main exceptions were some industries, most notably the mining industry, which as noted above in this unit, argued that the available data provide little evidence for coarse particle effects at current ambient levels. These groups, who generally opposed $PM_{2.5}$ standards, also argued that the daily PM_{10} standard could be eliminated if $PM_{2.5}$ standards were set. Based on the potential aggravation of respiratory symptoms from short-term exposure to coarse fraction particles discussed in the Criteria Document and by numerous commenters, as well as the recommendations of a majority of CASAC panelists who also supported $PM_{2.5}$ standards, the Administrator concludes it is appropriate to retain a 24-hour PM_{10} standard.

In general, comments received on the form of the 24-hour PM_{10} standard paralleled those on the form of the $PM_{2.5}$ standard. Substantial concerns were expressed by environmental groups, some States, and others that the 98th percentile would not provide an adequate limit on the number and magnitude of 24-hour peak PM_{10} excursions. While a number of these commenters suggested keeping the current 1-expected-exceedance form, EPA believes that a concentration- based percentile form offers significant advantages, as outlined above in this unit, for both PM indicators. Some air pollution control officials, who were concerned about the extent to which the 24-hour PM_{10} standard would be relaxed under the proposed form, suggested consideration of a 99th percentile form with increased monitoring as an appropriately protective form. Other commenters, particularly some industry groups and some States, strongly supported concentration-based percentile forms, with some recommending consideration of the 95th percentile form.

The proposal noted that a percentile value selected closer to the ''tail'' of the air quality distribution (e.g., a 99th or greater percentile) would not significantly increase stability as compared to the current form. However, an association of 8 State air pollution agencies commented that a 99th percentile form could provide increased stability if combined with a daily or 1-in-3-day sampling frequency and with greater data capture. In addition, EPA notes that this concentration-based form is inherently more stable than the current exceedance-based form.

Many of these and other commenters were concerned that the uncertainties in the available scientific information on the effects of coarse particles were a reason to be concerned that, assuming the current standard level was kept, a 98th percentile form would represent a significant relaxation in protection relative to the current standards. Unlike the situation for the new $PM_{2.5}$ standards, in the case of the PM_{10} standards, the 24-hour standard has generally been the ''controlling'' standard, making changes to the form of the 24-hour standard potentially more significant to the overall national level of protection afforded. Given the uncertainties in the available scientific evidence with respect to the potential health effects of short-term exposures to coarse fraction particles, the Administrator is persuaded that the somewhat more cautious approach with respect to revising the 24-hour PM_{10} standard recommended by many commenters is appropriate. The only approaches available for increasing the extent of protection for this standard as compared to that of the proposed standard involve modifying the form or reducing the level. For reasons discussed in the following section, the Administrator believes it is not appropriate to revise the level of the standard. In order to provide adequate protection against the potential risk associated with multiple short-term peak exposures to coarse fraction particles, the Administator accepts commenters' recommendations to decrease the frequency of peak values, while still providing for a more stable control target than afforded by the current 1-expected-exceedance form. Therefore, the Administrator concludes that the 99th percentile concentration-based form, averaged over 3 years, and combined with more frequent sampling, would be an appropriate form for a 24-hour PM_{10} standard.

2. *Levels for the annual and 24-hour PM_{10} standards*—a. *Annual PM_{10} standard.* As a result of the more limited information for coarse fraction particles, the Administrator's approach for selecting a level of the standard is directly related to the approach taken in the last review of the PM NAAQS. In that review, evidence from limited quantitative studies was used in conjunction with support from the qualitative literature in selecting the level of the current annual PM_{10} standard. In the current review, the staff assessment of the major quantitative basis for the level of that standard (Ware et al., 1986), together with a more recent related study (Dockery et al., 1989), recommended the same range of levels of concern (40 to 50 $\mu g/m^3$) as in the 1986 staff paper. The staff concludes that it is possible, but not certain, that coarse fraction particles, in combination with fine particles, may have influenced the observed effects at these levels. Based on particle deposition considerations, it is possible that cumulative deposition of coarse fraction particles could be of concern in children, who are more prone to be active outdoors than sensitive adult populations.

Qualitative evidence of other long-term coarse particle effects, most notably from long-term build-up of silica-containing materials, supports the need for a long-term standard, but does not provide evidence of effects below the range of 40 to 50 $\mu g/m^3$ (U.S. EPA, 1996a, p. 13-79). The staff concludes that the qualitative evidence with respect to biological aerosols also supports the need to limit coarse materials, but should not form the major basis for a national standard (U.S. EPA, 1996a, p. 13-79). In addition, staff notes that the nature and distribution of such materials, which vary from endemic fungi (e.g., valley fever) to pollens larger than 10 μm, are not appropriately addressed by traditional air pollution control programs.

Based on its review of the available information, CASAC found ''a consensus that retaining an annual PM_{10} NAAQS at the current level is reasonable at this time'' (Wolff, 1996b). With few exceptions, public comments supported levels at least as stringent as the current annual PM_{10} standard.[45] Taking into account these comments and the above considerations, as more fully detailed in the Staff Paper and the

[45] Some commenters, including some environmental groups and the State of California (Cal EPA, 1997), suggested that the large number of recent studies showing effects at PM_{10} levels below the current standards provides a basis for establishing stricter annual and 24-hour PM_{10} standards, in conjunction with $PM_{2.5}$ standards. As discussed in Units II.B. and C. of this preamble, while these studies could be used either to tighten the PM_{10} standards or to add standards that tighten control of the fine fraction of PM_{10}, the weight of evidence from all of the relevant information more readily supports the development of additional protection for the $PM_{2.5}$ fraction.

CASAC recommendations, the Administrator has decided to retain the current annual PM_{10} standard of 50 μg/m^3 to protect against the known and potential effects of long-term exposure to coarse fraction particles.

b. *24-hour PM_{10} standard.* As discussed above in this unit, EPA staff and CASAC also recommended that consideration be given to a 24-hour standard for coarse fraction particles as measured by PM_{10}. Unlike the case for the annual standard, however, the staff found that the original quantitative basis for the level of the current 24-hour PM_{10} standard (150 μg/m^3) is no longer appropriate. Instead, the staff found that the main quantitative basis for a short-term standard is provided by the two recent community studies of exposure to fugitive dust (Gordian et al., 1996; Hefflin et al., 1994). Because these studies reported multiple large exceedances of the current 24-hour standard, and because of limitations in the studies themselves, the staff concluded that they provide no basis to lower the level of the standard below 150 μg/m^3. Moreover, staff concluded that none of the qualitative literature regarding the potential effects of short-term exposure to coarse particles provides a basis for a lower standard level. Both EPA staff and CASAC recommended that if a 24-hour PM_{10} standard is retained, the level of the standard should be maintained at 150 μg/m^3, although with a revised form. Beyond the comments summarized above recommending elimination of the 24-hour standard, no commenters recommended a less stringent level, while some others, as summarized above in this unit, recommended more stringent levels. Most comments favored the current level.

Having considered these factors and the public comments, the Administrator judges that, retention of a 24-hour PM_{10} standard at the level of 150 μ/m^3 with a 99th percentile form is appropriate and will provide adequate protection against the known and potential effects of short-term coarse fraction particle exposures that have been identified to date in the scientific literature.

H. Final Decisions on Primary PM Standards

For the reasons discussed above in this unit, and taking into account the information and assessments presented in the Criteria Document and the Staff Paper, the advice and recommendations of CASAC, and public comments received on the proposal, the Administrator is revising the current PM NAAQS by adding new $PM_{2.5}$ standards and by revising the form of the current 24-hour PM_{10} standard. Specifically, the Administrator is making the following revisions:

(1) The suite of PM standards is revised to include an annual primary $PM_{2.5}$ standard and a 24-hour $PM_{2.5}$ standard.

(2) The annual $PM_{2.5}$ standard is met when the 3-year average of the annual arithmetic mean $PM_{2.5}$ concentrations, from single or multiple community-oriented monitors (in accordance with EPA's final rule on monitoring siting guidance, 40 CFR part 58, published in a separate document elsewhere in this issue of the **Federal Register**) is less than or equal to 15 μg/m^3, with fractional parts of 0.05 or greater rounding up.

(3) The 24-hour $PM_{2.5}$ standard is met when the 3-year average of the 98th percentile of 24-hour $PM_{2.5}$ concentrations at each population-oriented monitor within an area is less than or equal to 65 μg/m^3, with fractional parts of 0.5 or greater rounding up.

(4) The form of the current 24-hour PM_{10} standard is revised to be based on the 3-year average of the 99th percentile of 24-hour PM_{10} concentrations at each monitor within an area.

In addition, the Administrator is retaining the current annual PM_{10} standard at the level of 50 μg/m^3, which is met when the 3-year average of the annual arithmetic mean PM_{10} concentrations at each monitor within an area is less than or equal to 50 μg/m^3, with fractional parts of 0.5 or greater rounding up.

As discussed below in Units V. and VI. of this preamble, data handling conventions and completeness criteria for the revised standards are being established (40 CFR part 50, Appendix N). The reference method for monitoring PM as PM_{10} for the revised standards has been established (40 CFR part 50, Appendix M). A new reference method is being established for monitoring PM as $PM_{2.5}$ (40 CFR part 50, Appendix L). In a separate document published elsewhere in this issue of the **Federal Register**, EPA is providing opportunity for public comment on supplemental information relating to the new reference method for monitoring PM as $PM_{2.5}$ (40 CFR part 50, Appendix L).

As indicated previously, EPA plans to propose related revisions to the Pollutant Standards Index for PM (40 CFR 58.50) and the significant harm level program (40 CFR 51.66) at a later date.

III. Rationale for the Secondary Standards

The Criteria Document and Staff Paper examined the effects of PM on such aspects of public welfare as visibility, materials damage, and soiling. The following discussion of the rationale for revising the secondary standards for PM focuses on those considerations most influential in the Administrator's decision.

A. Need for Revision of the Current Secondary Standards

1. *Visibility impairment.* This unit of the document presents the Administrator's decision to address the welfare effects of PM on visibility by setting secondary standards identical to the suite of $PM_{2.5}$ primary standards, in conjunction with the establishment of a regional haze program under section 169A of the Act.[46] In the Administrator's judgment, this approach is the most effective way to address visibility impairment given the regional variations in concentrations of non-anthropogenic PM as well as other regional factors that affect visibility, such as humidity. By augmenting the protection provided by secondary standards set identical to the suite of $PM_{2.5}$ primary standards with a regional haze program, the Administrator believes that an appropriate degree of visibility protection can be achieved in the various regions of the country.

In coming to this decision, the Administrator took into account several factors, including: The pertinent scientific and technical information in the Criteria Document and Staff Paper, difficulties inherent in attempting to establish national secondary standards to address visibility impairment, the degree of visibility improvement expected through attainment of secondary standards equivalent to the suite of $PM_{2.5}$ primary standards, the effectiveness of addressing the welfare effects of PM on visibility through the combination of a regional haze program and secondary standards for $PM_{2.5}$ equivalent to the suite of primary standards, and comments received during the public comment period. The Administrator's consideration of each of these factors is discussed below in this unit.

The Administrator first concluded, based on information presented and referenced in the Criteria Document and

[46] Congress adopted section 169A of the Act because of concern that the NAAQS and Prevention of Significant Deterioration programs might not provide adequate visibility protection nationally, particularly for ''areas of great scenic importance.'' See H.R. Rep. No. 95–294,at 203–205 (1977).

Staff Paper, that particulate matter can and does produce adverse effects on visibility in various locations, depending on the PM concentrations involved and other factors discussed below. It has been demonstrated that impairment of visibility is an important effect of PM on public welfare, and that it is experienced throughout the United States, in multi-state regions, urban areas, and remote mandatory Class I Federal areas[47] alike. Visibility is an important welfare effect because it has direct significance to people's enjoyment of daily activities in all parts of the country. Individuals value good visibility for the well-being it provides them directly, both where they live and work, and in places where they enjoy recreational opportunities. Visibility is highly valued in significant natural areas, such as national parks and wilderness areas, because of the special emphasis given to protecting these lands now and for future generations. The Criteria Document cites many studies designed to quantify the benefits associated with improvements in visibility.

The Administrator considered information from the Staff Paper and Criteria Document regarding the effect of the composition of particulate matter on visibility. Visibility conditions are determined by the scattering and absorption of light by particles and gases, from both natural and anthropogenic sources. Visibility can be described in terms of visual range, light extinction, or deciview[48]. The classes of fine particles principally responsible for visibility impairment are sulfates, nitrates, organic matter, elemental carbon (soot), and soil dust. Fine particles are more efficient per unit mass at scattering light than coarse particles. The scattering efficiency of certain classes of fine particles, such as sulfates, nitrates, and some organics, increases as relative humidity rises because these particles can absorb water and grow to sizes comparable to the wavelength of visible light. In addition to limiting the distance that one can see, the scattering and absorption of light caused by air pollution can also degrade the color, clarity, and contrast of scenes.

The Administrator next considered what would be an appropriate level for a secondary standard to address adverse effects of particulate matter on visibility. The determination of a single national level is complicated by regional differences in visibility impairment due to several factors, including background and current levels of PM, composition of particulate matter, and average relative humidity.

The Criteria Document and Staff Paper describe estimated background levels of PM and natural light extinction. In the United States, estimated annual mean background levels of $PM_{2.5}$ are significantly lower in the West than in the East. Based on estimated background fine particle and light extinction levels summarized in Table VIII-2 of the Staff Paper, naturally occurring visual range in the East is approximately 105 to 195 kilometers, whereas in the West it is approximately 190 to 270 kilometers. This significant regional difference in estimated background conditions results from two main factors. First, in the western United States, visibility is more sensitive to an additional 1–2 $\mu g/m^3$ of $PM_{2.5}$ in the atmosphere than in the eastern United States. Secondly, light scattering is increased for certain particles (e.g., sulfates, nitrates, and some organics) due to higher average relative humidity in the East.

The combination of naturally occurring and manmade emissions also leads to significant differences in current visibility conditions between the eastern United States, 23–39 kilometers average visual range, and western United States, 55–150 kilometers average visual range. Table VIII-4 of the Staff Paper indicates that the current level of annual average light extinction in several western locations, such as the Colorado Plateau, is about equal to the level of background light extinction, i.e., the level generally regarded as representing the absence of anthropogenic emissions in North America, in the East. This regional difference is due to higher background particle concentrations in the East, a composition of fine particles in the East that, in association with higher eastern humidity levels, is more efficient at light scattering, and significantly lower concentrations of anthropogenic PM in remote western locations as compared with remote eastern sites.

Because of these regional differences, it is the Administrator's judgment that a national secondary standard intended to maintain or improve visibility conditions on the Colorado Plateau or other parts of the West would have to be set at or even below natural background levels in the East, which would effectively require elimination of all eastern anthropogenic emissions. Conversely, a national secondary standard that would achieve an appropriate degree of visibility improvement in the East would permit further degradation in the West. Due to this regional variability in visibility conditions created by differing background fine particle levels, fine particle composition, and humidity effects, the Administrator finds that addressing visibility solely through setting more stringent national secondary standards would not be an appropriate means to protect the public welfare from adverse impacts of PM on visibility in all parts of the country.[49] Aside from the problem of regional variability, the Administrator has also determined that the Agency currently lacks sufficient information to establish a level for a national secondary standard that would represent a threshold above which visibility conditions would always be adverse and below which visibility conditions would always be acceptable. Because visibility varies not only with PM concentration, but also with PM composition and humidity levels, attaining even a low concentration of fine particles might or might not provide adequate protection, depending on these factors.

The Administrator next assessed potential visibility improvements[50] that would result from attainment of the new primary standards for $PM_{2.5}$. The spatially averaged form of the annual standard is well suited to the protection of visibility, which involves effects of PM throughout an extended viewing distance across an urban area. Indeed, as

[47] There are 156 mandatory Class I Federal areas protected by the visibility provisions in sections 169A and 169B of the Act. These areas are defined in section 162 of the Act as those national parks exceeding 6,000 acres, wilderness areas and memorial parks exceeding 5,000 acres, and all international parks which were in existence on August 7, 1977.

[48] Visual range can be defined as the maximum distance at which one can identify a black object against the horizon sky. It is typically described in miles or kilometers. Light extinction is the sum of light scattering and absorption by particles and gases in the atmosphere. It is typically expressed in terms of inverse megameters (Mm^{-1}), with larger values representing poorer visibility. The deciview metric describes perceived visual changes in a linear fashion over its entire range, analogous to the decibel scale for sound. A deciview of 0 represents pristine conditions. Under many scenic conditions, a change of 1 deciview is considered perceptible by the average person.

[49] Congress adopted a visibility protection program in section 169A of the Act because it recognized the impracticability of revising the NAAQS to protect visibility in all areas of the country: ''It would be impracticable to require a major city such as New York or Los Angeles to meet the same visibility standards as the Grand Canyon and Yellowstone Park.'' See H.R. Rep. No. 95–294 at 205. (1977)

[50] Estimates of annual average visibility improvements assume that, on a percentage basis, the reduction for each fine particle component is equal to the % reduction in the mass of fine particles, and that the overall light extinction efficiency of the fine particle pollutant mix does not change. Further, for the estimates presented here, the reductions in fine mass at monitored locations are assumed to reflect the spatial average concentrations through the viewing distance. (Damberg and Polkowsky, 1996.)

the generally controlling standard focused on reducing urban and regional scale fine particle levels, most of the visibility protection provided by the $PM_{2.5}$ primary standards would be derived from the annual standard. In many cities having annual mean $PM_{2.5}$ concentrations exceeding 17 μg/m³, improvements in annual average visibility resulting from attainment of the new annual $PM_{2.5}$ primary standard are expected to be perceptible (i.e., to exceed 1 deciview). Based on annual mean $PM_{2.5}$ data reported in Table 12-2 of the Criteria Document and Table V-12 in the Staff Paper, many cities in the Northeast, Midwest, and Southeast, as well as Los Angeles, would be expected to see perceptible improvement in visibility if the annual $PM_{2.5}$ primary standard is attained.

In Washington, DC, for example, where the IMPROVE network[51] shows annual mean $PM_{2.5}$ concentrations at about 19 μg/m³ during 1992–1995, approximate annual average visibility would be expected to improve from 21 km visual range (29 deciview) to 27 km (27 deciview). Annual average visibility in Philadelphia, where annual $PM_{2.5}$ levels have been recently measured at 17 μg/m³, would be expected to change from about 24 to 27 km, an improvement of about 1 deciview. In Los Angeles, where recent data shows annual mean $PM_{2.5}$ concentrations at approximately 30 μg/m³, visibility would be expected to improve from about 19 to 34 km (30 to 24 deciview) if the new annual primary $PM_{2.5}$ standard is attained.

It is important to note that some urban areas, many in the eastern United States, would be expected to have annual mean $PM_{2.5}$ concentrations reduced below the primary standard level of 15 μg/m³ when implementation of regional control strategies for PM and other air quality programs, such as those addressing acid rain and mobile sources, are taken into account together. On the other hand, some urban areas with annual $PM_{2.5}$ levels at or below the 15 μg/m³ level would be expected to see little, if any, improvement in annual average visibility. This may be particularly true of certain western urban areas that are dominated by coarse rather than fine particles.

The Administrator also considered the potential effect on urban visibility if the 24-hour 98th percentile $PM_{2.5}$ standard of 65 m³ is attained. In areas with violations caused by localized hot spots, the 24-hour standard might have little effect other than on visible source emissions. In other areas, for example, with seasonally high woodsmoke, a more areawide improvement is possible. In such urban areas, attainment of the 24-hour standard would be expected to reduce, to some degree, the number and intensity of ''bad visibility'' days, i.e., the 20% of days having the greatest impairment over the course of a year. For example, maximum 24-hour $PM_{2.5}$ concentrations have been recorded in recent years at over 140 μg/m³ at several California locations. If the level and frequency of peak PM concentrations are reduced, improvements would be expected in those days where visibility is worst, even in urban areas having annual averages below the annual $PM_{2.5}$ primary standard.

Having concluded that attainment of the annual and 24-hour $PM_{2.5}$ primary standards would lead to visibility improvements in many eastern and some western urban areas, the Administrator also considered potential improvements to visibility on a regional scale. In the rural East, attainment of the $PM_{2.5}$ primary standards could result in regional visibility improvement, e.g., in certain mandatory Class I Federal areas such as Shenandoah and Great Smoky Mountains National Park, if regional control strategies are adopted and carried out in order to reduce the impact of long-range transport of fine particles such as sulfates. Fine particle emission reductions achieved by other air quality programs, such as those to reduce acid rain or mobile source emissions, are also expected to improve Eastern regional visibility conditions (U.S. EPA, 1993). In the West, strategies to attain the primary $PM_{2.5}$ standards are less likely to significantly improve visibility on a regional basis. However, areas downwind from large urban areas, such as Southern California, would likely see some improvement in annual average visibility.

Based on the foregoing, the Administrator concludes that attainment of $PM_{2.5}$ secondary standards set at the level of the primary standards for $PM_{2.5}$ would be expected to result in visibility improvements in the eastern United States at both urban and regional scales, but little or no change in the western United States except in and near certain urban areas. Additionally, the Administrator determined that attainment of secondary standards equivalent to the suite of $PM_{2.5}$ primary standards for particulate matter would address some but not all of the effects of particulate matter on visibility. The extent to which these effects would be addressed is expected to vary regionally.

The Administrator then considered the potential effectiveness of a regional haze program to address the remaining effects of particulate matter on visibility (i.e., those that would not be addressed through attainment of secondary standards identical to the suite of $PM_{2.5}$ primary standards). A program to address the widespread, regionally uniform type of haze caused by a multitude of sources is required by sections 169A and 169B of the Act. In 1977, Congress established as a national goal ''the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution'', section 169A(a)(1) of the Act. The EPA is required by section 169A(a)(4) of the Act to promulgate regulations to ensure that ''reasonable progress'' is achieved toward meeting the national goal. EPA originally deferred establishment of a program to address regional haze in 1980 due to the need for greater scientific and technical knowledge, but the current Criteria Document and Staff Paper cite information supporting the Administrator's conclusion that the scientific state of understanding and analytical tools are now adequate to develop such a program. Because regional emission reductions are needed to make visibility improvements in mandatory Class I Federal areas, the structure and requirements of sections 169A and 169B of the Act, provide for visibility protection programs that can be more responsive to the factors contributing to regional differences in visibility than can programs addressing a nationally applicable secondary NAAQS. The visibility goal is more protective than a secondary NAAQS since the goal addresses any man-made impairment rather than just impairment at levels determined to be adverse.

Thus, an important factor considered in this review is whether a regional haze program, in conjunction with secondary standards set identical to the suite of $PM_{2.5}$ primary standards, would provide appropriate protection for visibility in non-Class I areas. The Administrator continues to believe that the two programs and associated control strategies should provide such protection due to the regional approaches needed to manage emissions of pollutants that impair visibility in many of these areas. Regional strategies implemented to attain the NAAQS, meet other air program goals, and make reasonable progress toward the national visibility goal in mandatory Class I Federal areas are expected to improve

[51] IMPROVE (Interagency Monitoring of PROtected Visual Environments) is a visibility monitoring network managed cooperatively by EPA, Federal land management agencies, and State representatives. An analysis of IMPROVE data for 1992–1995 is found in Sisler et al. (1996).

visibility in many urban and non-Class I areas as well. The following recommendation from the 1993 report of the National Research Council, *Protecting Visibility in National Parks and Wilderness Areas,* addresses this point:

> Efforts to improve visibility in Class I areas also would benefit visibility outside these areas. Because most visibility impairment is regional in scale, the same haze that degrades visibility within or looking out from a national park also degrades visibility outside it. Class I areas cannot be regarded as potential islands of clean air in a polluted sea.

Before making a final decisions on the secondary standards, the Administrator also considered a number of public comments that addressed this aspect of the proposal. Some commenters suggested setting secondary standards for $PM_{2.5}$ more stringent than the proposed primary standards for the purpose of addressing visibility impairment and other environmental effects. For the reasons discussed above in this unit, however, the Administrator has concluded that this may not be an effective and would not be an appropriate means of protecting against visibility impairment in all parts of the country. Other commenters raised the possibility of establishing a nationally applicable secondary standard defined as a ''floor,'' or increment, above regionally specific background levels of $PM_{2.5}$ or associated visibility. Although this idea is of interest and may warrant further study, the Administrator determined that it was not appropriate to pursue such an approach at this time for two principal reasons. First, the Agency does not currently have adequate scientific information to establish a specific floor or increment level that would protect against adverse effects nationally, nor is it clear as a conceptual matter whether further information would support selection of a single, uniform increment as providing an appropriate degree of protection in all areas of the country. Second, there are serious, unresolved questions about whether such an approach is consistent with the statutory language and purposes of section 109 of the Act.

Other commenters argued that national secondary standards equivalent to the proposed $PM_{2.5}$ primary standards are not necessary or not supported by the Administrator's findings. As noted earlier, however, it is clear that coarse and fine particles can cause adverse effects on visibility and significant quantitative data exist to demonstrate that visibility impairment occurs at small concentrations of $PM_{2.5}$. Substantial efforts have been put forth to assess the effects of PM on visibility. For example, the Grand Canyon Visibility Transport Commission[52] spent several years and significant effort studying the effects of pollution on 16 mandatory Class I Federal areas on the Colorado plateau and has made recommendations to the Administrator for actions to improve visibility in these areas (GCVTC, 1996). All of the mandatory Class I Federal areas studied by the GCVTC with monitoring data have annual mean $PM_{2.5}$ concentrations below 5 $\mu g/m^3$ (Sisler, 1996) while also documenting anthropogenic visibility impairment. The Southern Appalachian Mountain Initiative[53] is currently assessing air pollution impacts on visibility, terrestrial resources, and aquatic resources in the southeastern U.S. in order to recommend measures to remedy existing and prevent future adverse effects on these air quality related values. The IMPROVE network shows that all of the mandatory Class I Federal areas in the SAMI region have annual mean $PM_{2.5}$ concentrations for 1992–95 between 11.0–13.5 $\mu g/m^3$ (Sisler, 1996). The inclusion in section 169A of the Act of a national visibility goal of no manmade impairment also places significant value on reducing PM concentrations and resulting visibility impairment to low levels.[54] The differences between the fine particle levels associated with visibility impairment in eastern and western mandatory Class I Federal areas provide further impetus to act under the provisions of sections 169A and 169B enabling the Administrator to establish a regionally-tailored visibility program to address impairment of visibility in mandatory Class I Federal areas. For these reasons, the Administrator has concluded that a national regional haze program allowing for regional approaches to addressing fine particle pollution, combined with a nationally applicable level of protection achieved through secondary $PM_{2.5}$ standards set equal to the suite of primary standards, would be more effective in addressing regional variations in the adverse effects of $PM_{2.5}$ on visibility than establishing national secondary standards for particulate matter that are lower than the suite of $PM_{2.5}$ primary standards. The Administrator emphasizes that in order to appropriately address the regional differences in adverse effects of particulate matter on visibility, it is essential to establish secondary standards for $PM_{2.5}$ equivalent to the primary standards and an effective new regional haze program. A regional haze program will be particularly important in those areas of the country that do not exceed any of the primary standards for $PM_{2.5}$, yet still experience significant visibility impairment due to particulate matter. The EPA will propose a regional haze regulation in the near future.

In addition to providing a more regionally tailored approach than establishing a more stringent national secondary standard, an effective regional haze program will also fulfill the Administrator's regulatory responsibility under sections 169A and 169B of the Act to address both reasonably attributable impairment and regional haze impairment in mandatory Class I Federal areas. Indeed, regional haze has been shown to be the principal cause of visibility impairment in mandatory Class I Federal areas today. Thus, the promulgation of a regional haze program in conjunction with secondary standards for $PM_{2.5}$ equivalent to the suite of primary standards will serve as an appropriate approach for addressing adverse effects of visibility that vary regionally, and it will also establish a comprehensive program for making reasonable progress toward the national visibility goal in mandatory Class I Federal areas by addressing visibility impairment in the form of both source-specific impacts and regional haze. Further, the regional haze rulemaking will fulfill the Administrator's responsibilities to address the visibility protection recommendations of the Grand Canyon Visibility Transport Commission, pursuant to section 169B(e) of the Act.

The Administrator recognizes that people living in certain urban areas may place a high value on unique scenic resources in or near these areas, and as a result might experience visibility problems attributable to sources that would not necessarily be addressed by the combined effects of a regional haze program and secondary standards identical to the suite of primary standards for $PM_{2.5}$. Commenters from

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[52] EPA established the Grand Canyon Visibility Transport Commission (GCVTC) in 1991 under section 169B of the Act. Section 169B(d) requires visibility transport commissions to assess the ''adverse impacts on visibility from potential or projected growth in emissions'' and to recommend to EPA measures to remedy such adverse impacts. The Commission issued its final report in June 1996.

[53] The Southern Appalachian Mountain Initiative is a voluntary effort begun in 1993. Participants include eight southeastern States, Federal land managers, EPA, and representatives from industry and environmental groups. A final report has not been issued to date.

[54] Indeed, Congress recognized when it adopted section 169A that the ''visibility problem is caused primarily by emission into the atmosphere of sulfur dioxide, oxides of nitrogen and particulate matter, especially fine particulate matter, from inadequately controlled sources.'' H.R. Rep. No. 95–294 at 204 (1977).

certain western cities and States raised this issue. In the Administrator's judgment, State or local regulatory approaches, such as past action in Colorado to establish a local visibility standard for the City of Denver, would be more appropriate and effective in addressing these special situations because of the localized and unique characteristics of the problems involved. Visibility in an urban area located near a mandatory Class I Federal area can also be improved through State implementation of the current visibility regulations, by which emission limitations can be imposed on a source or group of sources found to be contributing to ''reasonably attributable'' impairment in the mandatory Class I Federal area. EPA also intends to pursue opportunities to obtain information on urban and non-Class I area visibility through examination of available fine particle monitoring data. Current or planned monitoring networks and initiatives, such as monitoring and chemical analysis of $PM_{2.5}$ in urban and background sites, efforts to better characterize real-time environmental conditions in major populations centers, and new automated airport visibility monitoring networks should provide data needed to evaluate trends in these areas. This information should help to better characterize the nature and spatial extent of urban and non-Class I visibility problems and thus serve to inform future decisions on NAAQS revisions or other appropriate measures.

Based on all of the considerations discussed, the Administrator has decided to establish secondary standards identical to the suite of $PM_{2.5}$ primary standards, in conjunction with a regional haze program under sections 169A and 169B of the Act, as the most appropriate and effective means of addressing the welfare effects associated with visibility impairment. Together, the two programs and associated control strategies should provide appropriate protection against the effects of PM on visibility and enable all regions of the country to make reasonable progress toward the national visibility goal.

2. *Materials damage and soiling effects.* Annual and 24-hour secondary standards for materials damage and soiling effects of PM were established in 1987 at levels equal in all respects to the primary standards. As discussed in the Criteria Document and Staff Paper, particles affect materials by promoting and accelerating the corrosion of metals, by degrading paints, and by deteriorating building materials such as concrete and limestone. Soiling is found to reduce the aesthetic quality of buildings and objects of historical or social interest. Past studies have found that residential properties in highly polluted areas typically have lower values than those in less polluted areas. Thus, at high enough concentrations, particles become a nuisance and result in increased cost and decreased enjoyment of the environment.

In the proposal, EPA proposed to establish secondary standards for PM_{10} and $PM_{2.5}$ identical to the suite of proposed primary standards. Several comments recommended setting secondary standards at levels more stringent than the proposed primary standards in order to address various welfare effects of PM, including soiling and materials damage, acid deposition, and visibility. Some commenters specifically suggested changing the form or level of the proposed 24-hour, 98th percentile PM standards to better protect against elevated PM episodes and associated soiling, materials damage, and visibility effects.

After reviewing the extent of relevant studies and other information provided since the 1987 review of the PM standards, the Administrator concurs with staff and CASAC conclusions that the available data do not provide a sufficient basis for establishing a separate secondary standard based on soiling or materials damage alone. In the Administrator's judgment, however, setting secondary standards identical to the suite of $PM_{2.5}$ and PM_{10} primary standards would provide increased protection against the effects of fine particles and retain an appropriate degree of control on coarse particles. Accordingly, the Administrator establishes the secondary standards for $PM_{2.5}$ identical to the suite of primary standards to protect against materials damage and soiling effects of PM.

B. Decision on the Secondary Standards

The Administrator establishes secondary standards identical to the suite of primary standards. In the Administrator's judgment, the establishment of these standards, in conjunction with implementation of a regional haze program, will provide appropriate protection against the welfare effects associated with particle pollution.

IV. Other Issues

Commenters have raised a number of legal and procedural issues that are discussed in this unit. These include:

(1) Whether EPA must give consideration to costs and similar factors in setting NAAQS.

(2) Whether EPA erred in its selection of a methodology for determining the level of a NAAQS that protects public health with an adequate margin of safety.

(3) Whether EPA committed a procedural error by not entering into the rulemaking docket underlying data from certain epidemiological studies.

(4) Whether the 1990 amendments to the Act preclude EPA from revising the PM NAAQS to establish a new $PM_{2.5}$ indicator.

Responses to other legal and procedural issues are included in the Response-to-Comments Document.

A. Consideration of Costs

For more than a quarter of a century, EPA has interpreted section 109 of the Act as precluding consideration of the economic costs or technical feasibility of implementing NAAQS in setting them. As indicated in the proposal, a number of judicial decisions have confirmed this interpretation. *Natural Resources Defense Council* v. *Administrator*, 902 F.2d 962, 972–973 (D.C. Cir. 1990)(PM NAAQS)(''PM_{10}''), vacated, in part, dismissed, 921 F.2d 326 (D.C. Cir.), certs. dismissed, 498 U.S. 1075, and cert. denied, 498 U.S. 1082 (1991); *Natural Resources Defense Council* v. *EPA*, 824 F.2d 1146, 1157–1159 (D.C. Cir. 1987)(en banc)(CAA section 112 standards for vinyl chloride)(''Vinyl Chloride''); *American Petroleum Institute* v. *Costle*, 665 F.2d 1176, 1185–1186 (D.C. Cir. 1981)(ozone NAAQS)(''Ozone''), cert. denied, 455 U.S. 1034 (1982); *Lead Industries Ass'n* v. *EPA*, 647 F.2d 1130, 1148–1151 (D.C. Cir.)(lead NAAQS)(Lead Industries), cert. denied, 449 U.S. 1042 (1980).

Some commenters have argued that costs and similar factors should, nonetheless, be considered, both in this rulemaking and in the rulemaking on proposed revisions to the NAAQS for ozone. Although most of the commenters' arguments are inconsistent with the judicial decisions cited in this unit, several commenters have argued that those decisions are not dispositive. For reasons discussed in this unit and in the Response-to-Comments Document, EPA disagrees with these comments and maintains its longstanding interpretation of the Act as precluding consideration of costs and similar factors in setting NAAQS.

1. *Background.* Given the nature of the points raised, a brief review of the issue seems useful before addressing the comments. The requirement that EPA establish national ambient air quality standards for certain pollutants, to be implemented by the States, was enacted in 1970 as part of a set of comprehensive amendments that established the basic framework for

Federal, State, and local air pollution control. When EPA promulgated the original NAAQS in 1971, its first Administrator, William D. Ruckelshaus, concluded that costs and similar factors could not be considered in that decision.[55] This conclusion was not challenged in litigation on the original NAAQS. It has been confirmed since then, however, by every judicial decision that has considered the issue.

As discussed in this unit, EPA's interpretation rests primarily on the language, structure, and legislative history of the statutory scheme adopted in 1970. It is also supported by the judicial decisions cited in this unit, as well as by legislative developments since 1970 that reaffirm Congress' original approach to the issue.

Without cataloguing all relevant aspects of the 1970 amendments and their legislative history, several basic points should be noted. Under section 109(b) of the Act, NAAQS are to be ''based on'' the air quality criteria issued under section 108 of the Act. Under section 108(a)(2) of the Act, the kind of information EPA is required to include in criteria documents is limited to information about health and welfare effects ''which may be expected from the presence of [a] pollutant in the ambient air * * * .'' There is no mention of the costs or difficulty of implementing the NAAQS, nor of ''effects'' that might result from implementing the NAAQS (as opposed to effects of pollution in the air).[56] By contrast, Congress explicitly provided for consideration of costs and similar factors in decisions under other sections of the Act.[57] Moreover, States were permitted to consider economic and technological feasibility in developing plans to implement the NAAQS to the extent such consideration did not interfere with meeting statutory deadlines for attainment of the standards.[58] Finally, the legislative history indicated that Congress had considered the issue and had deliberately chosen to mandate NAAQS that would protect health regardless of concerns about feasibility.[59]

The first judicial decision on the issue came in the Lead Industries case. An industry petitioner argued that EPA should have considered economic and technological feasibility in allowing a ''margin of safety'' in setting primary standards for lead. Based on a detailed review of the language, structure, and legislative history of the statutory scheme, the U.S. Court of Appeals for the District of Columbia Circuit concluded that:

> This argument is totally without merit. [The petitioner] is unable to point to anything in either the language of the Act or its legislative history that offers any support for its claim * * * . To the contrary, the statute and its legislative history make clear that economic considerations play no part in the promulgation of ambient air quality standards under section 109.

647 F.2d at 1148.

The Court cited a number of reasons for this conclusion. *Id.* at 1148–1150. Among other things, it noted the contrast between section 109(b) of the Act and other provisions in which Congress had explicitly provided for consideration of economic and technological feasibility, as well as the requirement that NAAQS be based on air quality criteria defined without reference to such factors. *Id.* at 1148–1149 and n.37. The Court also noted that, in developing plans to implement NAAQS, States may consider economic and technological feasibility only to the extent that this does not interfere with meeting the statutory deadlines for attainment of the standards; and that EPA may not consider such factors at all in deciding whether to approve State implementation plans. *Id.* at 1149 n.37 (citing *Union Electric Co.* v. *EPA*, 427 U.S. 246, 257–258, 266 (1976)).[60]

As to the legislative history of the 1970 amendments, the Court observed that:

> [T]he absence of any provision requiring consideration of these factors was no accident; it was the result of a deliberate decision by Congress to subordinate such concerns to the achievement of health goals.

Id. at 1149. Citing several leading Supreme Court decisions, as well as the Senate report quoted in this unit, the Court noted that Congress had intended a drastic change in approach toward the control of air pollution in the 1970 amendments and was well aware that sections 108–110 of the Act imposed requirements of a ''technology-forcing'' character. *Id.*[61]

The Court also noted that Congress had already acted, in further amendments adopted in 1977, to relieve some of the burdens imposed by the 1970 amendments. *Id.* at 1150 n.38. Observing that Congress had, however, declined to amend section 109(b) of the Act to provide for consideration of costs and similar factors as requested by industrial interests, *Id.* n.39, the Court concluded:

> A policy choice such as this is one which only Congress, not the courts and not EPA, can make. Indeed, the debates on the [1970 amendments] indicate that Congress was quite conscious of this fact * * * .
>
> * * * [I]f there is a problem with the economic or technological feasibility of the lead standards, [the petitioner], or any other party affected by the standards, must take its case to Congress, the only institution with the authority to remedy the problem.

Id. at 1150.

After the decision in Lead Industries, Supreme Court review was sought on the question whether costs and similar factors could be considered in setting NAAQS, among other issues. The Supreme Court declined to review the decision. *Lead Industries Ass'n* v. *EPA*, 449 U.S. 1042 (1980). The subsequent decisions in Ozone, Vinyl Chloride, and PM_{10}, cited in this unit, strongly reaffirmed the interpretation adopted in Lead Industries.[62] Supreme Court

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[55] 36 FR 8186, April 30, 1971. EPA has maintained this interpretation consistently since then.

[56] That consideration of such factors was not intended in NAAQS decisions is also supported by section 109(a)(1) of the Act. For pollutants for which air quality criteria had been issued prior to the 1970 amendments, that provision required EPA to propose NAAQS within 30 days after enactment and to take final action 90 days later. The criteria issued previously did not include information on costs and similar factors, and it would have been difficult if not impossible for EPA to supplement them in time to include meaningful consideration of such factors in NAAQS proposed 30 days after enactment.

[57] See, e.g., sections 110(e)(1), 111(a)(1), 231(b) of the 1970 Act; see also, e.g., sections 113(d)(4)(C)(ii), 125(a)(3), 202(a)(3)(C), 317 of the 1977 Act.

[58] *Union Electric Co.* v. *EPA*, 427 U.S. 246, 257–58 (1976).

[59] The Senate report on the 1970 amendments stated: ''In the Committee discussions, considerable concern was expressed regarding the use of the concept of technical feasibility as the basis of ambient air standards. The Committee determined that (1) the health of people is more important than the question of whether the early achievement of ambient air quality standards protective of health is technically feasible; and, (2) the growth of pollution load in many areas, even with application of available technology, would still be deleterious to public health.''

''Therefore, the Committee determined that existing sources of pollutants either should meet the standard of the law or be closed down * * * .''

S. Rep. No. 91–1196, at 2–3 (1970).

[60] These limitations would, of course, make little sense if such factors could be considered in setting the NAAQS themselves.

[61] Such requirements ''are expressly designed to force regulated sources to develop pollution control devices that might at the time appear to be economically or technologically infeasible.''' *Id.* (quoting *Union Electric Co.* v. *EPA*, 427 U.S. at 257).

[62] In the PM_{10} case, for example, the Court considered an argument that EPA should have considered potential health consequences of unemployment that might result from revision of the primary NAAQS for PM:

> ''This claim is entirely without merit. In three previous cases, this court has emphatically stated that § 109 does not permit EPA to consider such costs in promulgating national ambient air quality standards * * * . It is only *health effects relating to pollutants in the air* that EPA may consider * * * . Consideration of costs associated with alleged health risks from unemployment would be flatly inconsistent with the statute, legislative history and case law on this point.''

902 F.2d at 973 (emphasis in original; citations omitted).

review of the Ozone and PM_{10} decisions was sought but denied. *American Petroleum Institute* v. *Gorsuch,* 455 U.S. 1034 (1984); *American Iron and Steel Institute* v. *EPA*, 498 U.S. 1082 (1991).

The Lead Industries opinion focused largely, though not exclusively, on the 1970 amendments and their legislative history. Perhaps as a result, it did not canvass all the factors that, in fact, supported its conclusions at the time. For example, when Congress enacted major amendments to the Act in 1977, it was clearly aware that some areas of the country had experienced difficulty in attempting to attain some of the NAAQS.[63] It was also aware that there might be no health-effects thresholds for the pollutants involved, and that significant uncertainties are inherent in setting health-based standards under the Act.[64] In response, Congress made significant changes in the provisions for implementation of the NAAQS, including changes intended to ease the burdens of attainment. It also amended sections 108 and 109 of the Act in several ways; for example, by requiring periodic review and, if appropriate, revision of air quality criteria and NAAQS and by establishing a special scientific advisory committee (CASAC) to advise EPA on such reviews. Notably, Congress recognized that implementation of NAAQS could cause ''adverse public health, welfare, social, economic, or energy effects'' and charged CASAC with advising EPA on such matters.[65] Yet it made no changes in section 109(b) or section 108(a)(2) of the Act; that is, in the substantive criteria for setting or revising NAAQS. In other words, Congress chose to address economic and other difficulties associated with attainment of the NAAQS by adjusting the scheme for their implementation, rather than by changing the instructions for setting them.[66]

Congress enacted major amendments to the Act again in 1990, well after the Lead Industries and Ozone decisions that interpreted section 109 of the Act as precluding consideration of costs in NAAQS decisions.[67] In doing so, Congress was clearly aware of intervening developments such as EPA's decision to revise the PM NAAQS in 1987—the result of an elaborate review in which the Administrator strongly underscored the scientific uncertainties involved[68]—and the Vinyl Chloride case drawing a sharp distinction between sections 109 and 112 of the Act with regard to consideration of costs and similar factors.[69] Indeed, the legislative history of the 1990 amendments reflects Congress' understanding that primary NAAQS were to be based on protection of health ''without regard to the economic or technical feasibility of attainment.''[70] Again, however, Congress chose to respond to severe, widespread, and persistent problems with attaining the NAAQS by adjusting the scheme for their implementation rather than by changing the basis for setting them. See, e.g., sections 181–192 of the Act.

2. *Public comments.* As noted previously, a number of commenters have argued that costs and similar factors should be considered in EPA's final decisions on revision of both the particulate and ozone NAAQS. Aside from arguments that are simply inconsistent with the judicial decisions cited in this unit, some of the commenters argue that those decisions are not dispositive for a variety of reasons. One commenter submitted a particularly comprehensive version of this argument; the following discussion focuses primarily on points raised by that commenter, among others.[71]

As a general matter, the commenter acknowledges that Congress intended to preclude consideration of economic costs and similar factors in setting NAAQS. The commenter argues, however, that this is so only when the scientific basis for NAAQS is ''clear and compelling'' or ''unambiguous.'' From that premise, the commenter advances three key assertions:

a. Where non-threshold pollutants are involved and the health evidence is ambiguous, section 109 of the Act must be interpreted to allow consideration of all relevant factors, including the practical consequences of EPA's decisions.

b. To the extent the judicial decisions cited in this unit are read as precluding this, they rest on a faulty analysis that pre-dates and cannot survive scrutiny under *Chevron, U.S.A.* v. *Natural Resources Defense Council,* 467 U.S. 837 (1984).[72]

c. Because EPA has discretion to consider costs and similar factors where the health evidence is ambiguous, it must do so in light of Executive Order 12866 (58 FR 51735, October 4, 1993), and two recent statutes, the Unfunded

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[63] See, e.g., H.R. Rep. No. 95-294, at 207–217 (l977).

[64] See, e.g., *Id.* at 110–112; *Id.* at 43-51.

[65] Section 109(d)(2)(C)(iv) of the Act. Some commenters have argued that this provision requires EPA to consider such effects in setting NAAQS. From the language and structure of section 109(d) of the Act, however, it is clear that CASAC's responsibility to advise on these factors is separate from its responsibility to review and recommend revision of air quality criteria and NAAQS, and that the advice pertains to the implementation of NAAQS rather than to setting them. The legislative history confirms this view, indicating that the advice was intended for the benefit of the States and Congress. See H.R. Rep. No. 95-294, at 183 (1977).

[66] The 1977 amendments also required EPA to prepare economic impact assessments for specified actions but limited the requirement to non-health-based standards, excluding decisions under sections 109 and 112 of the Act. Section 317; H.R. Rep. No. 95-294, at 51–52 (1977). In this and other respects, Congress continued the approach it took in the l970 amendments, making careful choices as to when consideration of costs and similar factors would be required and giving paramount priority to protection of health. See 123 Cong. Rec. H8993 (daily ed. Aug. 4, 1977) (Clean Air Conference Report (1977); Statement of Intent; Clarification of Select Provisions), reprinted in 3 Senate Committee on Environment and Public Works, 95th Cong., A Legislative History of the Clean Air Act Amendments of 1977, at 319 (1978).

[67] In the interim, the National Commission on Air Quality had also submitted its report to Congress as required by a provision of the 1977 amendments. Among other things, the Commission recommended that the statutory approach of requiring NAAQS to be set at levels necessary to protect public health, without consideration of economic factors, be continued without change. National Commission on Air Quality, To Breathe Clean Air 55 (1981).

[68] As the Administrator indicated in EPA's proposal to revise the PM standards:

''[T]hat review has revealed a highly limited data base—particularly where quantitative studies are concerned—and a wide range of views among qualified professionals about the exact pollution levels at which health effects are likely to occur. The setting of an 'adequate margin of safety' below these levels calls for a further judgment—in an area for which the scientific data base is even more sparse and uncertain * * * .''

''* * * [L]ong and expert review of public health issues has to date revealed no scientific method of assessing exactly what level of standards public health requires. The scientific review indicates substantial uncertainties concerning the health risks associated with lower levels of particulate matter.'' (49 FR 10408, 10409, March 20, l984)

[69] Congress was clearly aware of the 1987 decision to revise the PM NAAQS, which among other things involved changing the indicator for particulate matter from ''total suspended particulate'' to PM_{10}, because it enacted special nonattainment provisions, as well as provisions for PSD increments, applicable to PM_{10}. Sections 188–190 of the Act; section 166(f) of the Act. It was clearly aware of the Vinyl Chloride decision because it amended section 112 of the Act in response to that decision, essentially creating a new scheme for setting emission standards for hazardous pollutants.

[70] H.R. Rep. No. 101–490, pt. 1, at 145 (1990). See also S. Rep. No. 101–228, at 5 (1989).

[71] Additional responses to points raised by this commenter and others are included, as appropriate, in the Response-to-Comments Document.

[72] Several other commenters argue that the cited decisions are not dispositive because they held only that EPA is not required to consider costs and similar factors in setting NAAQS. As discussed in this unit in connection with Chevron, however, the decisions clearly concluded that Congress intended to preclude consideration of such factors, and that EPA is not free to alter that congressional choice. Although these conclusions are technically dicta, nothing in the Court's opinions suggests that it would have interpreted section 109 of the Act differently had EPA claimed authority to consider costs and similar factors in NAAQS decisions. Indeed, the tone of the opinions argues to the contrary. See, e.g., PM_{10}, 902 F.2d at 973. Cf. *Ethyl Corp.* v. *EPA,* 51 F.3d 1053 (D.C. Cir. 1995).

Mandate Reform Act of 1995, 2 U.S.C. 1501–1571 (UMRA), and the Small Business Regulatory Enforcement Fairness Act of 1996, Pub. L. 104–121, 110 Stat. 857 (SBREFA), which in part amended the Regulatory Flexibility Act, 5 U.S.C. 601–808.

EPA believes all three assertions are clearly incorrect. Regarding the first point, it should be evident, both from previous NAAQS decisions and from the court opinions upholding them, that the scientific basis for NAAQS decisions has never pointed clearly and unambiguously to a single ''right answer.''[73] This is inherent in the statutory scheme for the establishment and revision of NAAQS, which in effect requires them to be based on the ''latest scientific knowledge'' on potential health and welfare effects of the pollutant in question. See sections 109(b) and 108(a)(2) of the Act. Although advances in science increase our understanding of such effects, they also raise new questions. For this reason, the key studies for any given decision on revision of a NAAQS are, almost by definition, ''at the very 'frontiers of scientific knowledge.'''[73] That is, studies that call into question the adequacy of a standard are always those that go beyond previous studies—by reporting new kinds of effects, for example, or effects at lower concentrations than those at which effects have been reported previously.

As with pioneering work in other fields, such studies may have a variety of strengths and limitations.[8][75] As a result, the validity and implications of such studies may be both uncertain and highly controversial. Given the precautionary nature of section 109 of the Act,[76] however, it is precisely these kinds of studies that the Administrator must grapple with when advances in science suggest that revision of a NAAQS is appropriate.

As a result, the EPA staff typically recommends for consideration, and the Administrator may propose for comment, a range of alternatives based on what the commenter would call ''ambiguous'' science. In this respect, the current reviews of the NAAQS for ozone and particulate matter are not unusual and do not differ, for example, from the review that led to adoption of the PM_{10} NAAQS in 1987.[77] Indeed, the NAAQS that were upheld in the Lead Industries, Ozone, and PM_{10} decisions were all based on highly controversial health evidence; the Lead Industries decision took note of congressional statements recognizing that there may be no thresholds for criteria pollutants; and the Ozone and PM_{10} decisions noted the Administrator's findings that clear thresholds could not be identified for ozone and particulate matter, respectively.[78] Thus, the present decisions on revision of the NAAQS for ozone and particulate matter cannot be distinguished from those past decisions in terms of the nature of the health evidence or pollutants involved.[78]

Regarding the second of the commenter's key assertions, EPA determines it is clear that the judicial decisions cited in this unit were correctly decided and continue to be good law under Chevron. In Chevron, the Supreme Court essentially reaffirmed the principle that courts must defer to reasonable agency interpretations of the statutes they administer where Congress has delegated authority to them to elucidate particular statutory provisions. Where the intent of Congress on an issue is clear, however, it must be given effect by the agency and the courts. See 467 U.S. at 842–45. Thus, the first question on review of an agency's interpretation under Chevron is ''whether Congress has directly spoken to the precise question at issue.'' If the court determines that it has not, the remaining question for the court is ''whether the agency's answer is based on a permissible construction of the statute.'' 467 U.S. at 842–843 (footnote omitted). In determining whether Congress ''had an intention on the precise question at issue,'' a court employs ''traditional tools of statutory construction.'' *Id.* at 843 n.9.[80]

In essence, the commenter's argument here is that the Lead Industries decision did not address whether Congress had ''spoken directly'' to the precise issue posed by the commenter; that is, whether section 109 of the Act must be interpreted differently for NAAQS decisions involving non-threshold pollutants and ''ambiguous'' health evidence. The Lead Industries opinion, which pre-dated Chevron, did not pose the question in those terms. Its focus, however, was clearly on what Congress intended to be the basis for NAAQS decisions, in a context the Court understood to involve considerable uncertainty and debate about the health evidence, as well as the possibility that there was no threshold for health effects of the pollutant.[81] In short, the health evidence was hardly ''unambiguous,'' yet the Court interpreted section 109 of this Act as precluding consideration of costs and similar factors even in allowing a margin of safety. Nothing in the Lead Industries decision or in the subsequent cases suggests in any way that section 109 of the Act should be interpreted differently based on the nature of the pollutants or health evidence involved, and the Court's findings on congressional intent admit of no exceptions:

> * * * [T]he statute and its legislative history make clear that economic considerations play no part in the promulgation of ambient air quality standards under Section 109.

647 F.2d at 1148.

Alternatively, the commenter argues that the Lead Industries case decided the issue incorrectly in light of the principles announced subsequently in Chevron. In this context, the commenter essentially argues that the Lead Industries decision rested on two factors that are no longer probative:

(1) That there was no indication that Congress meant to allow consideration of costs in NAAQS decisions, and

(2) That Congress specifically provided for such consideration in other sections of the Act but not in section 109.

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[73] See, e.g., Lead Industries, 647 F.2d at 1146–1147, 1153–1156, 1160–1161, 1167 n.106. In enacting the 1970 amendments, Congress was aware that there were gaps in the scientific information available then as a basis for establishing the original NAAQS. See, e.g., S. Rep. No. 91-1196, at 9–11 (1970). If anything, Congress had an even greater understanding of the point when it enacted the 1977 amendments without changing the substantive criteria for setting NAAQS. See H.R. Rep. No. 95-294, at 43–51, 181–182 (1977).

[74] Lead Industries, 647 F.2d at 1147 (quoting *Ethyl Corp.* v. *EPA*, 541 F.2d 1, 24–27 (D.C. Cir.) (en banc), cert. denied, 426 U.S. 941 (1976)).

[75] They may have methodological flaws, for example, but nonetheless report effects that are of serious medical significance; or they may be of impeccable quality but involve effects of uncertain significance. Others may involve results that are striking but hard to explain in terms of previous knowledge, or results that seem plausible and important but are not yet replicated by other studies.

[76] See, e.g., Lead Industries, 647 F.2d at 1155–1156; H.R. Rep. No. 94-295, at 43–51 (1977).

[77] As previously discussed, the Administrator strongly emphasized the uncertainties involved in that review. As a result of the uncertainties, he proposed ''relatively broad'' ranges for comment, though he focused on lower levels within the ranges as providing greater margins of safety against the health risks involved. See 49 FR 10408, 10409, March 20, l984.

[78] See, e.g., Lead Industries, 647 F.2d at 1152–53 and n. 43, 1159–60; Ozone, 665 F.2d at 1185, 1187; PM_{10}, 902 F.2d at 969–71, 972.

[79] Indeed, the present decisions on the NAAQS for PM and ozone are based on some of the best scientific information the Agency has ever been able to rely on in NAAQS decision-making. In particular, the science underlying these decisions is much more extensive and of much better quality than the science underlying the existing NAAQS for PM and ozone.

[80] In practice, analysis of this question is sometimes referred to as a ''Chevron step one'' analysis.

[81] See, e.g., 647 F.2d at 1148–51, 1152–53 and n.43, 1160–61.

On the first point, the commenter argues that EPA is free under Chevron to consider costs and similar factors (by reinterpreting section 109 of the Act) unless there is evidence that Congress intended to restrict its discretion. As to the second point, the commenter argues that similar reasoning was rejected in Vinyl Chloride.

In Vinyl Chloride, however, an en banc decision that post-dated Chevron, the Court essentially underscored the point that such issues cannot be decided mechanically but must turn, instead, on more analytical attention to relevant indicia of congressional intent. See, e.g., 824 F.2d at 1157 n.4; *Id.* at 1157–1163. With reference to NAAQS decisions in particular, the Court concluded that there were concrete indications of congressional intent to preclude consideration of costs and similar factors; for example, the fact that section 108 of the Act ''enumerate[s] specific factors to consider and pointedly exclude[s] feasibility.'' 824 F.2d at 1159. In a later case, moreover, the same Court held that EPA could not consider certain factors, in decisions under section 211(f)(4) of the Act, for reasons exactly parallel to those that the commenter criticizes in Lead Industries. See *Ethyl Corp.* v. *EPA*, 51 F.3d 1053, 1057–1063 (D.C. Cir. 1995).

Beyond this, the commenter's characterization of the Lead Industries decision ignores or discounts much of the key evidence cited by the Court, including the language, structure, and legislative history of the statutory scheme established in 1970, for its conclusion that Congress intended to preclude consideration of costs and similar factors in NAAQS decisions.[82] As indicated in this unit, the Vinyl Chloride and PM_{10} cases, both of which post-dated Chevron, reached the same conclusion.

Moreover, this series of decisions went far beyond mere deference to an agency interpretation. As indicated in the Vinyl Chloride case, the Lead Industries court found ''clear evidence'' of Congressional intent, which was to limit the factors EPA may consider under section 109 of the Act. 824 F.2d 1159. Consistent with Chevron, these findings were based on traditional tools of statutory construction. See *Id.* at 1157–1159; Lead Industries, 647 F.2d at 1148–1151. In terms of the analytical framework later established by Chevron, these were Chevron step one findings, meaning that the statute spoke directly to the issue and that the courts, as well as the agency, must give effect to Congress' intent as so ascertained. See 467 U.S. at 842–843.[83] Thus, absent a more recent legislative enactment overriding that intent, EPA has no discretion to alter its longstanding interpretation that consideration of costs and similar factors is precluded in NAAQS decisions under section 109 of the Act.[84]

As to the commenter's third key assertion, Executive Order 12866, UMRA sections 202 and 205, and the Regulatory Flexibility Act (RFA), as amended by SBREFA, do not conflict with this interpretation or require a different result. Basically, the commenter argues that the Executive Order, UMRA, and the RFA (as amended by SBREFA) require agencies to use cost (or similar factors) as a decisional criterion in making regulatory decisions, and that this modifies the Clean Air Act's directive that EPA is precluded from considering costs when setting a NAAQS. The commenter's argument is flawed on a number of grounds. First, UMRA and the RFA (as amended by SBREFA) do not conflict with section 109 of the Act because they do not apply to this decision, as discussed in Unit VIII. of this preamble. Second, the Executive Order and both statutes are quite clear that they do not override the substantive provisions in an authorizing statute. Third, the commenter's premise that UMRA and the RFA (as amended by SBREFA) establish substantive decisional criteria that agencies are required to follow is wrong.

As a matter of law, the Executive Order cannot (and does not purport to) override the Clean Air Act. The Executive Order does not conflict with section 109 of the Act because the requirement that agencies ''select approaches that maximize net benefits'' does not apply if a ''statute requires another regulatory approach.'' Executive Order 12866, section (1)(a), (58 FR 51735, October 4, 1993). More generally, the Executive Order provides that agencies are to adhere to its regulatory principles only ''to the extent permitted by law.'' *Id.*, section (1)(b).

UMRA sections 202 and 205 do not apply to this decision, as discussed in Unit VIII. of this preamble. Even when they do apply to a regulatory action, they do not establish decisional criteria that an agency must follow, much less override decisional criteria established in the statute authorizing the regulatory action. UMRA does not require an agency to select any particular alternative. Rather, an agency can select an alternative that is not the least costly, most cost-effective or least burdensome if the agency explains why. Section 205(b)(1) of UMRA. Such an explanation is not required if the least costly, most cost-effective or least burdensome alternative would have been ''inconsistent with law,'' section 205(b)(2) of UMRA, and the only alternatives that an agency should consider are ones that ''achieve[] the objectives of the rule,'' section 205(a) of UMRA. The UMRA Conference Report confirms that UMRA does not override the authorizing statute. ''This section [202] does not require the preparation of any estimate or analysis if the agency is prohibited by law from considering the estimate or analysis in adopting the rule.'' 141 Cong. Rec. H3063 (daily ed. March 13, 1995).

The RFA (as amended by SBREFA) also does not apply to this decision, as

[82] See 647 F.2d at 1148–51. By contrast, the commenter's argument that Congress actually intended EPA to consider such factors relies heavily on statements made in subsequent legislative history, most of which were made in floor debate, that sought to justify controversial amendments to establish a different program than the NAAQS and did not involve any proposed changes in section 109 of the Act or related provisions; and statements in early judicial decisions involving programs under other statutory provisions. In context, EPA determines these and other statements cited by the commenter are consistent with and do not alter the conclusion that Congress intended to preclude consideration of costs and similar factors under section 109 of the Act.

[83] The commenter argues that the post-Chevron cases accepted the Lead Industries analysis uncritically rather than re-examining it under Chevron. Clearly, this elevates form over substance. It is true that neither case referred to Chevron in discussing the point at issue. In Vinyl Chloride, however, the Court retraced the steps in the Lead Industries analysis in some detail, characterized some of the key evidence reviewed in that analysis in terms going beyond mere rote repetition (e.g., ''a far clearer statement than anything in the present case that Congress considered the alternatives''), and used Chevron-like language in discussing the significance of that evidence; that is, that it demonstrated congressional intention on the point at issue. E.g., 824 F.2d at 1159. Given that the Vinyl Chloride case was decided three years after Chevron, that it was an en banc decision of the D.C. Circuit involving interpretation of statutory language very similar to that in Lead Industries, and that the Court cited Chevron twice in analyzing the language and history of section 112 of the Act, it seems highly unlikely that the Court was unmindful of Chevron principles in concluding that Congress intended to preclude consideration of costs under section 109 of the Act but not under section 112 of the Act.

In the PM_{10} decision, the Court confirmed the sharp distinction it had drawn, based on such evidence of congressional intent, between sections 109 and 112 of the Act in Vinyl Chloride. 902 F.2d at 972–973. Although discussion of the point was brief and did not mention Chevron, the industry petitioner raising the point had cited Chevron in arguing that the Lead Industries interpretation was not binding, and that EPA's decision on the PM_{10} standards should be reversed on the ground that it rested on a legal position that EPA unjustifiably believed was mandated by Congress. Reply Brief of the American Iron and Steel Institute at 11 and n.10, *Natural Resources Defense Council* v. *Administrator*, 902 F.2d 962 (D.C. Cir. 1990) (Nos. 87-1438 et al.). Thus, Chevron issues were properly before the Court and were brought squarely to its attention.

[84] See also 52 FR 24854, July 1, 1987.

discussed in Unit VIII. of this preamble. As is the case with UMRA, even when the RFA (as amended by SBREFA) does apply to a regulatory action, it does not establish decisional criteria that an agency must follow, much less override the underlying substantive statute. When the RFA was adopted in 1980, Congress made clear that it did not alter the substantive standards contained in authorizing statutes: ''The requirements of section 603 and 604 of this title [to prepare initial and final regulatory flexibility analyses] do not alter in any manner standards otherwise applicable by law to agency action.'' Section 606 of the RFA. The legislative history further explains that section 606 ''succinctly states that this bill does not alter the substantive standard contained in underlying statutes which defines the agency's mandate.''[85] When Congress passed SBREFA in 1996 and amended parts of the RFA, it did not amend section 606.

Even when a regulatory decision is subject to sections 603 and 604 of the RFA and an agency is therefore required to analyze alternatives that minimize significant economic impacts on small entities, the RFA (as amended by SBREFA) does not establish decisional criteria that an agency is required to follow. Both section 603 and 604 of the RFA provide that the alternatives an agency should consider are to be ''consistent with the stated objectives of applicable statutes.'' Section 603(c) and 604(a)(5) of the RFA. Furthermore, although the RFA (as amended by SBREFA) requires agencies to consider alternatives that minimize impacts on small entities subject to the rules' requirements and to explain their choice of regulatory alternatives, it does not require agencies to select such alternatives. For these reasons, the RFA (as amended by SBREFA) does not conflict with or override the Clean Air Act's preclusion of considering costs and similar factors in setting NAAQS.

3. *Conclusion.* In summary, EPA determines that the judicial decisions cited in this unit are both correct and dispositive on the question of considering costs in setting NAAQS, and that the Agency is not free to reinterpret the Act on that question.

B. Margin of Safety

Several commenters questioned the approach used by the Administrator in specifying PM standards that protect public health with an adequate margin of safety. Rather than the integrative approach applied by the Administrator, these commenters maintained that EPA must employ a two-step process. One line of argument was that the Administrator must first determine a ''safe level'' and then apply a margin of safety taking into account costs and societal impacts. It was argued that this was the only approach that would enable the Administrator to reach a reasoned decision on a standard level that protects public health against unacceptable risk of harm, such that any remaining risk was ''acceptable.'' In effect, these commenters adopted the two-step methodology endorsed by Vinyl Chloride, 824 F.2d 1146, for setting hazardous air pollutant standards under section 112 of the Act. Another commenter also maintained that the Administrator must apply a two-step process but from a different perspective. It was argued that EPA should first identify the lowest observed effect level and then apply a margin of safety to address uncertainties and to protect the most sensitive individuals within the at-risk population(s). This commenter also maintained that the use of risk assessment in establishing a NAAQS was a departure from past practice, and that this departure was not adequately explained.

In recognition of the complexities facing the Administrator in determining a standard that protects public health with an adequate margin of safety, the courts have declined to impose any specific requirements on the Administrator's methodological approach. Thus, in Lead Industries the court held that the selection of any particular approach to providing an adequate margin of safety ''is a policy choice of the type Congress specifically left to the Administrator's judgment. This court must allow him the discretion to determine which approach will best fulfill the goals of the Act.'' 647 F.2d at 1161–1162. As a result, the Administrator is not limited to any single approach to determining an adequate margin of safety and, in the exercise of her judgment, may choose an integrative approach, a two-step approach, or perhaps some other approach, depending on the particular circumstances confronting her in a given NAAQS review.

With respect to the approaches advanced in comment, the PM_{10} case made clear that the two-step process endorsed in Vinyl Chloride was necessary because of the need under section 112 of the Act to ''sever determinations that must be based solely on health considerations from those that may include economic and technical considerations.'' 902 F.2d at 973. Because the Administrator may not consider cost and technological feasibility under section 109 of the Act, however, the Court concluded that ''the rationale for parsing the Administrator's determination into two steps is inapposite.'' *Id.*

The claim that EPA must follow a two-step process of first identifying the lowest observed effects level and then applying a margin of safety has also been rejected by the courts. In Lead Industries, the Court specifically held that the Administrator need not apply a margin of safety at the end of the analytical process but may take into account margin of safety considerations throughout the process as long as such considerations are fully explained and supported by the record. 647 F.2d 1161–1162. Accord, PM_{10}, 902 F.2d at 973–974.

Because such factors as the nature and severity of the health effects involved, the size of the sensitive population(s) at risk, the types of health information available, and the kind and degree of uncertainties that must be addressed will vary from one pollutant to another, the most appropriate approach to establishing a NAAQS with an adequate margin of safety may be different for each standard under review. Thus, no generalized paradigm such as that imbedded in EPA's cancer risk policy can substitute for the Administrator's careful and reasoned assessment of all relevant health factors in reaching such a judgment. As noted in this unit, both Congress and the courts have left to the Administrator's discretion the choice of analytical approaches and tools, including risk assessments, rather than prescribing a particular formula for reaching such determinations.[86] Because of the inherent uncertainties that the Administrator must address in margin of safety determinations, they are largely judgmental in nature, particularly with respect to non-threshold pollutants, and may not be amenable to quantification in terms of what risk is ''acceptable'' or any other metric. In view of these considerations, the task of the Administrator is to select an approach that best takes into account the nature of the health effects and other information assessed in the air quality criteria for the pollutant in question and to apply appropriate and reasoned analysis to ensure that scientific

[85] 126 Cong. Rec. 21452, 21455 (1980) (Description of Major Issues and Section-By-Section Analysis of Substitute for S. 299).

[86] Contrary to one of the comments received, EPA's use of risk assessment in this rulemaking is by no means a departure from past practice. The EPA first considered and began applying risk assessment methods in the late 1970's (44 FR 8210, 8211, February 8, 1979).

uncertainties are taken into account in an appropriate manner.

In this instance, the Administrator has clearly articulated the factors she has considered, the judgments she has had to make in the face of uncertain and incomplete information, and alternative views as to how such information should be interpreted, in reaching her decision on standard specifications that will protect public health with an adequate margin of safety. See Unit II. of this preamble. Her conclusions on these matters are fully supported by the record.

C. Data Availability

Several commenters questioned EPA's ability to rely on studies demonstrating an association between PM and excess mortality without obtaining and disclosing the raw ''data'' underlying these studies for public review and comment. In particular, a number of commenters cited Dockery, D.W., et al. 1993 and Pope, C.A. III, et al., 1995, as studies upon which EPA relied without obtaining and disclosing the underlying raw data. One commenter also cited J. Schwartz et al., 1996 in the same context.[87] According to the commenters, without the underlying data used in these studies, the reliability of these studies cannot be assessed accurately. These commenters requested that EPA obtain the relevant data and make it available for public review. In light of the court-ordered requirement that EPA publish its rule by July 19, 1997, the commenters argued that EPA must retain the current PM_{10} NAAQS pending additional review of the raw data and the studies at issue. One commenter, the American Petroleum Institute (API) requested that EPA remove the studies from the docket, unless the underlying data was also included in the docket.[88]

A few commenters argued that section 307(d) of the Act requires that EPA obtain the raw data underlying these studies and that a failure to do so contradicts the plain language of section 307(d)(3) of the Act, which requires EPA to place in the docket any ''factual data on which the proposed rule is based.'' Other commenters argued that under section 307(d)(8) of the Act, a failure to obtain and disclose the underlying raw data used in the studies would constitute an error ''so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made.'' *Id.* According to one commenter, without the raw data and an opportunity for an analysis of it, ''EPA has no legal alternative other than to conclude that no new air quality standard would be appropriate within the meaning of CAA section 109(a)(1)(B).'' Finally, a number of commenters have argued that recent caselaw under the Clean Air Act and other statutes makes clear that EPA has a legal obligation to obtain and disclose the data used in these studies.[89]

In developing the proposed revisions to the PM NAAQS, the Administrator relied on the scientific studies cited in the rulemaking record, rather than on the raw data underlying them.[90] In this case, the raw data consists of responses to health questionnaires based on information supplied by individual citizens, or computer tabulations of this information, which remains confidential, and air quality and monitoring data, most of which is now publicly available. EPA does not generally undertake evaluations of raw, unanalyzed scientific data as part of its public health standard setting process. Only in extreme cases—for example where there are credible allegations of fraud, abuse or misconduct—would a review of raw data be warranted. It would be impractical and unnecessary for EPA to review underlying data for every study upon which it relies as support for every proposed rule or standard. If EPA and other governmental agencies could not rely on published studies without conducting an independent analysis of the enormous volume of raw data underlying them, then much plainly relevant scientific information would become unavailable to EPA for use in setting standards to protect public health and the environment. In addition, such data are often the property of scientific investigators and are often not readily available because of the proprietary interests of the investigators or because of arrangements made to maintain confidentiality regarding personal health status and lifestyle information of individuals included in such data. Without provisions of confidentiality, the possibility of conducting such studies could be severely compromised.[91]

In this case, the merits of the studies considered and used in developing the $PM_{2.5}$ standard have been discussed and debated extensively over the past several years, both as part of the EPA review of the pertinent science and in a number of other public forums. The studies at issue were critically evaluated

[87] Contrary to this commenter's assertion, both the health and air quality data used in the 1996 Schwartz study are available to interested parties. EPA's Office of Research and Development maintains a copy of the air pollution database used in the Schwartz study and it has previously been made available in response to Freedom of Information Act requests from interested parties, such as the American Iron and Steel Institute (AISI). The Harvard School of Public Health has also made this data available to several collaborators and to the Health Effects Institute. With regard to the health data underlying the Schwartz study, that mortality data was compiled by the National Center for Health Statistics (NCHS) and can be purchased from the NCHS by interested parties. Thus, there is no real data availability concern with regard to the 1996 Schwartz study. However, even were this not the case, for the reasons discussed more fully in this unit and elsewhere in the preamble, EPA believes it would be entitled to rely upon this study and other studies, including the Dockery and Pope studies, regardless of the availability of the underlying health data.

[88] API's letter stated that ''API petitions EPA to identify all studies that rely, in any way, on data not available for public review as part of the rulemaking process and remove those studies from the record.'' To the extent this letter constitutes a ''petition'' for EPA action, EPA hereby denies the ''petition'' for the reasons stated in this unit and elsewhere in this preamble.

[89] One commenter argued that the failure to obtain and disclose the underlying data was a violation of the Administrative Procedure Act (APA). The NAAQS rulemaking is promulgated under section 307(d) of the Act; the APA generally does not apply to such rulemakings. See section 307(d)(1) of the Act.

[90] It is important to note that while EPA did use the Dockery and Pope studies to confirm its conclusions regarding the health effects of fine particulate air pollution and thus as support for its decision to revise the PM standard, these studies do not provide the sole (or even primary) basis for EPA's decision regarding $PM_{2.5}$, despite the assertions of numerous commenters. The proposed standards are based on a consideration of a large body of epidemiological studies, a clear majority of which suggest PM is strongly linked to mortality and other serious health effects at concentrations permitted under the current standards. Although the specific levels of the $PM_{2.5}$ standards are based on a more limited number of studies that actually measured fine particles and/or components of fine particles, the Dockery and Pope studies were not used in initially selecting the annual fine particle standard level, which was principally based on examination of other daily mortality and respiratory effects studies (Koman, 1996, 1997) that found significant associations between fine PM and effects in cities with annual average $PM_{2.5}$ concentrations of about 16 to 21 μg/m3. Only then were the long-term Dockery and Pope studies examined and used to help corroborate this result; in the opinion of the Administrator, neither study alone (or together) provided sufficient evidence to support more stringent levels below those identified from the daily studies. Thus, removal of the Dockery and Pope studies would not affect the conclusions about the significance of the risks and therefore, while these long-term studies tend to strengthen the need for fine particle control and provide important insights into the nature of PM effects, removal of these two studies from consideration would not have changed the selected standard level.

[91] Some commenters noted that with regard to the health data underlying the 1993 Dockery and 1995 Pope studies, since EPA provided partial funding for these studies, EPA has access to this data and cannot shield itself from the duty to obtain this data by claiming that it is not in its possession. Although a legal argument potentially exists that EPA may obtain access to such data, this legal argument has not been tested in the courts. More importantly, EPA's ability to rely on studies without reviewing the raw data should not depend on whether some Agency of the Federal government funded the science.

by the Agency's Office of Research and Development (ORD) and by the EPA's independent Clean Air Scientific Advisory Committee (CASAC), in a multi-year process for assessment of the science at issue. As with other studies on which EPA relied, particular attention was given to the strengths and limitations of the Dockery, Schwartz and Pope studies during this process, which involved numerous opportunities for public participation and extensive input from interested parties. The results of these studies are not only consistent with each other, but they are also consistent with the results of other studies demonstrating significant associations between long-term exposure to fine particle indicators and mortality. See U.S. EPA, 1996b, p. V–62. The CASAC concluded that EPA's assessments of the pertinent science properly characterized both the current state of knowledge and the range of policy options for revising the standards.

In fact, many peer reviewed studies have reported associations between PM and premature death; the Dockery, Schwartz and Pope studies are among the most recent studies to corroborate this association. In the early 1990s, several studies were published showing associations at levels below the current PM standards. Some critics began raising questions about the extent to which the results could be reproduced and the unavailability of underlying data. In response, an independent group of investigators under the auspices of the Health Effects Institute (HEI), a highly respected research organization jointly funded by EPA and several motor vehicle manufacturers, undertook a reanalysis of several such studies. The original investigators of several studies, including studies conducted at Harvard University, Brigham Young University, and the San Francisco Bay Area Air Quality Management District provided their raw air quality data sets to the HEI investigation team for reanalysis. HEI's reanalysis produced numerical results from the data sets for all six cities that closely agree with and, in general, confirm the results of the original investigators. Thus, as noted in Unit II. of this preamble, these reanalyses by respected independent scientists confirmed the reliability and reproduceability of prior work of the original investigators, including work by Dockery et al. (1992), Pope et al. (1992), Schwartz and Dockery (1992a), and Schwartz (1993).

Thus, the 1993 Dockery and 1995 Pope studies build upon previous studies done by a number of different researchers and have been subject to an extensive peer review process by EPA's ORD, CASAC and HEI. They also underwent a peer review process at the time of their publication in reputable scientific journals. Given the consistency and coherence of the scientific evidence and the scrutiny the studies have received in peer review and in the extensive scientific review process described in this unit, EPA does not agree that review of the underlying data for these studies is also necessary. Considering the various reviews described in this unit and the fact that EPA has received no specific and substantiated reason, such as plausible allegations of fraud or scientific abuse, to doubt the overall validity of their conclusions, EPA agrees with CASAC that revision of the standard is appropriate, based on these and other studies.

In spite of EPA and CASAC's conclusion that it is appropriate to rely on the Pope, Dockery and other studies to establish a $PM_{2.5}$ NAAQS, EPA also believes in public disclosure and supports efforts to seek appropriate release of data underlying the studies in question. On January 31, 1997, EPA wrote to the principal scientific investigators at the Harvard School of Public Health and at Brigham Young University and urged them to make the data associated with their studies available to interested parties. Studies conducted by these investigators relied on data compiled as part of the Harvard Six-Cities Study and data compiled by the American Cancer Society (ACS) as part of the Cancer Prevention Study II.

The studies in question combined health data on individuals with air pollution data. The air pollution data are publicly available. The health data consist of personal and confidential information, e.g. age, sex, weight, eduction level, smoking history, occupational exposures, medical history. These data are not publicly available. In compiling these data, researchers have promised study participants that private, personal information would be kept confidential under signed assurances of confidentiality. Data-sharing arrangements with outside parties must, therefore, accommodate interests both in making data accessible and in protecting the confidentiality of the information contained within them.

Both the Harvard School of Public Health and the American Cancer Society have made such arrangements. Both have processes which allow ouside scientists, in collaboration with Harvard and ACS researchers, to access their databases for the conduct of legitimate scientific research. Scientists from all over the world have applied for and have been granted such access and numerous studies have been conducted and published using the databases.

Because of increased interest resulting from EPA's rulemaking on PM standards and at the request of the Harvard School of Public Health, HEI is taking additional steps to provide a forum for outside researchers to access health data associated with the Harvard-Six Cities Study and perhaps others. HEI has convened an expert panel of esteemed scientists to access underlying data and to conduct additional reanalyses. This arrangement appears to provide a constructive venue for testing legitimate scientific hypotheses while protecting the confidentiality of the underlying data.

Nevertheless, as noted previously, EPA has full confidence in the scientific integrity of the Dockery, Schwartz, and Pope studies and their suitability for use in the Agency's rulemaking on PM, without undertaking a separate or additional review and analysis of the underlying raw data. The decision to propose revisions of the current PM standards was based on careful assessment of the scientific and technical information presented in the PM Criteria Document and Staff Paper. The decision was also consistent with the consensus of CASAC that ''although an understanding of health effects of PM is far from complete, the Staff Paper, when revised, will provide an adequate summary of our present understanding of the scientific basis for making regulatory decisions concerning PM standards.'' The extensive PM epidemiological data base provides evidence that serious adverse health effects, e.g., mortality, exacerbation of chronic disease, increased hospital admissions, respiratory symptoms, and pulmonary function decrements, in sensitive subpopulations, e.g., the elderly, individuals with cardiopulmonary disease and children, are attributable to PM at levels below the current standards. The increase in risk is significant from an overall public health perspective because of the large number of individuals in sensitive subpopulations that are exposed to ambient PM and the significance of the health effects. These considerations, as well as others discussed in the proposal and Staff Paper, such as the need to consider fine and coarse particles as distinct classes, led both the Administrator and CASAC to conclude that revision of the current standards is clearly appropriate. This conclusion remains unchanged despite the fact that EPA is without the actual raw and

unanalyzed health data underlying the studies.

A number of commenters cited section 307(d) of the Act in support of their position that EPA is required to obtain and disclose the underlying raw data. Under section 307(d)(3) of the Act, EPA is required to issue a notice of proposed rulemaking in the **Federal Register** that is accompanied by a ''statement of basis and purpose'' that includes ''a summary'' of:

(A) The factual data on which the proposed rule is based.

(B) The methodology used in obtaining the data and in analyzing the data.

Thus, it is clear from the language of section 307(d) of the Act that where EPA relies on any ''data'' as support in its rulemakings under the Clean Air Act, it has an obligation to include such data or information in the rulemaking docket that is open to the public. Where EPA fails to do so and the error is ''so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made,'' a reviewing court may overturn the rule.

In this case, as noted previously, EPA did not rely upon the raw health data supporting the Dockery and Pope studies; it relied instead upon the studies themselves. These studies may properly be considered ''data.'' The EPA has never had the raw health data in its possession; thus EPA has neither reviewed it nor had an opportunity to place it in the docket. The EPA did rely on the studies and these studies are included in the docket and are available for public review. Because EPA neither reviewed nor relied upon the raw data, there is no obligation to obtain it or to make it available.

Some commenters argued that the language of section 307(d) of the Act, which refers to the ''factual data'' and which also discusses the ''methodology used in obtaining and analyzing the data'' distinguishes between raw data and studies. In the view of these and other commenters, the plain language of section 307(d) of the Act requires that EPA obtain and disclose the raw data used in the Dockery and Pope studies. According to these commenters, without such raw ''data,'' EPA cannot legally promulgate its rule.

The EPA disagrees with this narrow interpretation of the word ''data'' and of section 307(d) of the Act. Data can take many forms, including studies, reports, tabulations, graphs and summaries, as well as more raw forms, such as questionnaire responses, test results and even actual physical specimens. The ''factual data'' called for by section 307(d) of the Act may clearly include peer-reviewed scientific studies. Nor does section 307(d) of the Act prohibit EPA from relying on a study for standard setting without obtaining the raw, underlying data supporting a study. Indeed, as noted in the legislative history to section 307(d) of the Act,

> * * * [t]he [House Commerce] Committee recognizes that the factual support needed for a rule may vary greatly according to the subject being addressed and that rules on some subjects, such as procedures, may not require any factual basis at all. There is no intention to increase the amount of 'factual' support now required to support 'policy judgments where no factual certainties exist or where facts alone do not provide the answer,' Industrial Union Department, *AFL-CIO* v. *Hodgson*, 499 F.2d 467, 476 (D.C. Cir. 1974). Nor is there any intent to diminish the Administrator's authority to adopt precautionary regulations based on a showing of risk * * * .

H.R. Rep. No. 95-294, at 323 (1977) (footnote omitted). As this legislative history makes clear, the language in section 307(d) of the Act is not intended to require EPA to change the amount of ''factual support'' that EPA must assemble in order to promulgate a rule and EPA may adopt ''precautionary'' regulations ''where no factual certainties exist.'' Given this clarification in the legislative history, it is evident that EPA is entitled under section 307(d) of the Act to rely on studies rather than raw data in developing its Clean Air Act rules, despite the arguably ambiguous use of the term ''data.''[92]

Moreover, EPA has relied on studies in the past (including studies using the undisclosed Six Cities data) without obtaining or disclosing the underlying raw data, and EPA's reliance on such studies to set Clean Air Act standards has been upheld in court. In *NRDC* v. *EPA*, 902 F. 2d 962 (D.C. Cir. 1990), the D.C. Circuit declined to delay its review of the PM_{10} NAAQS rulemaking due to concerns raised by the American Iron and Steel Institute about the integrity of the Six Cities data base. 902 F.2d at 974. In that case, EPA had relied upon an earlier Dockery study based on the Six Cities data base. Although the National Institutes of Health (NIH) undertook a review of the allegations regarding the Six Cities database, the court nevertheless upheld EPA's reliance on that Dockery study without waiting for the results of the NIH review. NIH eventually concluded that the allegations were without merit. According to the court in the NRDC case:

> AISI claims that the EPA relied *too much* on the Six Cities Study, which is comprised of the Dockery study and the Ware study * * * . We do not agree that the Administrator's selection of the twenty-four hour standard lacks the necessary reasoned analysis and supportive evidence * * * . After carefully reviewing the record, we find EPA's selection of the twenty four hour standard reasonable in light of the divergent results in the studies and the agency's mandate to provide an adequate margin of safety. Studies contained in the record provided evidence of adverse health effects at levels below 250 μg/m3.

902 F.2d at 969 (footnotes omitted; *emphasis in original*). The court also stated that:

> In setting a standard under section 109 of the Act, the Administrator must ''take into account all the relevant studies revealed in the record'' and ''make an informed judgment based on available evidence.'' *American Petroleum Institute* v. *Costle*, 665 F.2d at 1187. The record shows that the Administrator did so. The Administrator relied on studies which showed adverse effects at and below the 250 μg/m3 level. AISI essentially asks this court to give different weight to the studies than did the Administrator. We must decline. It is simply not the court's role to ''second-guess the scientific judgments of the EPA. * * * [T]he Administrator did not act arbitrarily in drawing conclusions from the uncertain and conflicting data. The Administrator may reasonably apply his expertise to draw conclusions from ''imperfect data,'' Ethyl Corp., 541 F.2d at 28, as he did here.

Id. at 971.

As this language makes plain, the term ''data'' may include a study relied upon by EPA. It should be equally plain that EPA may properly rely on such a study in setting a standard despite the fact that such ''data'' may be ''imperfect,'' ''conflicting,'' and ''uncertain.'' There are numerous other cases in which EPA has relied on studies in setting standards under the Clean Air Act. See, e.g., *Engine Manufacturers Association* v. *EPA*, 88 F. 3d 1075, 1099 (D.C. Cir. 1996)(upholding EPA's use of the 1993 Dockery study for setting mobile source standards); *API* v. *Costle*, 665 F.2d 1176, 1185 (D.C. Cir. 1981)(Administrator's conclusion that normal body functions

[92] EPA also does not agree that because the language of section 307(d) of the Act mentions ''factual data'' as well as ''the methodology used in obtaining and analyzing the data,'' EPA cannot rely on a study alone. In this case, the study is the ''factual data'' and EPA's methodology used in obtaining and analyzing the ''factual data'' is the method that EPA used to review and rely upon the studies. This methodology is discussed extensively in the staff paper and summarized in some detail elsewhere in this preamble. In fact, as is clear from the overall structure of section 307(d) of the Act, as well as the legislative history cited in this unit, section 307(d) of the Act merely requires that EPA summarize and disclose the information and methodology that it relied upon in developing its rule. It leaves unchanged the ''level'' of support that an agency must bring to bear in drafting a proposed rule.

are disrupted by ozone is ''supported by the studies'').

A number of commenters cited *Endangered Species Committee* v. *Babbitt,* 852 F. Supp. 32 (D.D.C. 1994) (hereafter ''Gnatcatcher'') in support of the proposition that EPA must obtain and disclose the raw data underlying the Dockery and Pope studies. Relying on cases such as *Connecticut Light and Power Co.* v. *NRC,* 673 F.2d 525 (D.C. Cir. 1982), *Portland Cement* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973), and *United States* v. *Nova Scotia Food Processing Corp,* 568 F.2d 240 (2nd Cir. 1977), these commenters suggest that ''a body of legal decisions is emerging whereby federal courts are increasingly dubious of final regulatory decisions that are being made absent public scrutiny of the data underlying and purportedly supporting such decisions.'' According to these commenters, based on Gnatcatcher and other cases, failure by EPA to obtain and place in the docket the raw unanalyzed data used in the Dockery and Pope studies constitutes serious procedural error under the Clean Air Act.

Under Connecticut Light and Power, agencies must make available technical studies and data that have been relied upon during the rulemaking process in order for the public to have an adequate opportunity for notice and comment. There is no question that EPA has done this with regard to the Dockery and Pope studies, which are included in the rulemaking docket. The Portland Cement case makes clear that where an agency actually relies on factual data it cannot ''promulgate rules on the basis of inadequate data, or on data that, [to a] critical degree, is known only to the agency.'' 486 F.2d at 393. See also, Nova Scotia, 568 F.2d 240, at 251 (where all of the research was collected by the agency, and none of it was disclosed ''as the material upon which the proposed rule would be fashioned,'' error resulted); *CMA* v. *EPA,* 870 F.2d 177, 200 (5th Cir. 1989) (''fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency'').

However, in this case, EPA did not rely on, nor did it ever have or review, the underlying data used in the Dockery and Pope studies. Instead, it relied upon the studies themselves. Thus, the cases cited in this unit are inapposite. They stand only for the proposition that where an agency actually reviews and relies on ''data,'' which may be raw data, a study or a variety of other forms of information, it must make these data available. They do not and cannot stand for the proposition that an agency may not rely on a study alone and must always obtain the raw and unanalyzed data underlying a study. Indeed, as one D.C. Circuit case noted: ''Portland Cement and Nova Scotia simply cannot be twisted so as to require notices of proposed or interim rules to contain elaborate reproductions of underlying studies.'' *Petry* v. *Block,* 737 F.2d 1193, 1198 (D.C. Cir. 1984). Requiring EPA to obtain, analyze and disclose the data underlying the Pope and Dockery studies, which EPA neither reviewed nor relied upon, would be to require EPA to attempt such an ''elaborate reproduction.'' Such a step is not required under the law and would make it extremely difficult, if not impossible, for EPA to regulate in complex, technical areas ''at the frontiers of science.'' *Baltimore Gas and Electric Co.* v. *NRC,* 462 U.S. 87 (1983).

The district court's decision in the Gnatcatcher case is similarly inapposite. That case concerned a scientific study regarding the range of the California Gnatcatcher, a small insectivorous songbird. As the Gnatcatcher opinion itself notes, ''courts have generally allowed agencies to rely on scientific reports.'' Gnatcatcher, 852 F.Supp. at 37. Thus, the question at issue in Gnatcatcher was whether specific circumstances exist in which an agency may not be entitled to rely on studies alone. In the Gnatcatcher case, a single author had published two directly contradictory studies on the same issue, while relying on the same data. In light of this clear contradiction, commenters in that rulemaking argued that without the underlying data it was impossible to determine whether the conclusions in either study were correct. The district court noted that:

> The Secretary had before him a report by an author who, two years before had analyzed the same data and come to an opposite conclusion. It is the disputed nature of this report that distinguishes this from other cases where a scientific report alone has been considered sufficient for ESA purposes.

Id. Thus, according to the court: ''While courts have generally allowed agencies to rely on scientific reports * * * this is not sufficient in this case because the report itself is under serious question.'' *Id.*

The EPA's current reliance on the Dockery and Pope studies bears no resemblance to the circumstances present in the Gnatcatcher decision. As noted previously, these studies have been subject to extensive peer review and scrutiny, and neither researcher has published a contradictory study on the same issue, much less using the same data base. The EPA is not aware of, nor have any of the commenters raised any particular issues relating to either gross error, fraud or scientific abuse arising from the data. Indeed, as noted previously, the prior work of these particular researchers has been subject to extensive independent scrutiny and reanalysis, which has confirmed, rather than called into question, the underlying validity of their conclusions and the integrity of their research methods. Reading Gnatcatcher to suggest that EPA cannot rely on such a study, where the study and its methods have been subject to extensive peer review, would place the district court's rationale in Gnatcatcher in conflict with applicable D.C. Circuit precedent that makes evident the right of agencies to rely on studies alone. See, e.g., *Engine Manufacturers Association* v. *EPA,* 88 F.3d 1075, 1099 (D.C. Cir 1996); *API* v. *Costle,* 665 F.2d 1176, 1185 (D.C. Cir. 1981), ''studies discussed in the Criteria Document constitute a rational basis for the finding that adverse health effects occur at ozone levels of 0.15-0.25 ppm for sensitive individuals''; see also, *NRDC* v. *Thomas,* 805 F.2d 410, 418 (D.C. Cir. 1986)(EPA use of a summary of confidential data that was not disclosed provides ''a reasoned explanation for moving from a 4.0 to 5.0 long term NOx standard'').

In addition, to require EPA to obtain and analyze the data prior to revising the standard would also contradict the ''common sense notion that Congress, in providing for notice and comment under the APA, could not have intended to subject the agencies—and the public on whose behalf they regulate—to [a] sort of interminable back and forth.'' *International Fabricare Institute* v. *EPA,* 972 F.2d 384, 399 (D.C. Cir. 1992). In the view of some commenters, EPA has no choice but to either postpone its decision for a year or more awaiting a review of data or choose to retain the current standard. Yet were EPA to adopt such an approach, these commenters would undoubtedly insist that EPA be required to include an analysis of the data in the docket; further questions would likely be raised regarding the re-analysis and once again EPA might find itself unable to promulgate its rule pending review of further hypothetical questions. This type of unending inquiry is not required under the law. As the D.C. Circuit has noted:

> * * * [D]isagreement among the experts is inevitable when the issues involved are at the ''very frontiers of scientific knowledge,'' and such disagreement does not prevent us from finding that the Administrator's decisions are adequately supported by the evidence in the record * * * . It is not our function to resolve disagreement among the experts or to judge

the merits of competing expert views * * * . Cf. *Hercules, Inc.* v. *EPA,* 598 F.2d 91,115 (D.C. Cir. 1978) (''[c]hoice among scientific test data is precisely the type of judgment that must be made by EPA, not this court'').

Lead Industries Association v. *EPA,* 647 F.2d 1130, 1160 (D.C. Cir. 1980).

Neither Gnatcatcher, nor any other case can fairly be read to suggest that EPA has an obligation to respond to all possible questions that might be raised regarding its scientific conclusions or that where EPA relies on a study, it must engage in a multi-phased and possibly unending re-examination of the data supporting such a study until all commenters are satisfied in full with the details of the underlying science. Even assuming that EPA could obtain the confidential Six Cities data through litigation, a substantial delay of many months, if not years, would likely result, in order for both EPA and industry to reanalyze the data. In the meantime, some tens of thousands of premature deaths could result. Neither the Clean Air Act nor relevant case law requires or permits such a result.

Indeed, the suggestion that EPA cannot and should not rely upon the Pope, Dockery, and Schwartz studies, unless and until interested parties have had an opportunity to examine and reanalyze the underlying raw data, is extraordinary. Given the precautionary nature of section 109 of the Act and the need to allow an adequate margin of safety, see Lead Industries, 647 F.2d at 1154, 1155, there are limits on EPA's discretion to disregard even studies that are clearly flawed, if they are nonetheless ''useful'' in indicating the kind and extent of health effects that may result from the presence of a pollutant in the ambient air. See sections 109(b)(1) and 108(a)(2) of the Act.

A few commenters cited *Kennecott* v. *EPA,* 684 F.2d 1007 (D.C. Cir. 1982) and argued that under sections 307(d)(8) and 307(d)(9)(D) of the Act, a failure by EPA to obtain and include in the docket the data underlying the Pope and Dockery studies would constitute an ''error'' that is ''so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such error[] had not been made.''[93] EPA disagrees. Peer reviewed studies conducted by outside parties were not at issue in Kennecott. Kennecott involved a dispute over financial analyses that EPA itself had previously conducted and used in earlier rulemakings. The court determined that the financial analyses at issue must have provided at least part of the factual basis for EPA's rule, and EPA referenced these analyses in the preamble to the final rule without placing them in the docket until one week before promulgation. The factual circumstances in Kennecott are substantially different than the current situation and thus, Kennecott cannot fairly be read to establish the applicable legal standard with regard to EPA's reliance on peer reviewed studies for use in setting the NAAQS.

In this case, EPA—well before proposal—has placed the information that it relied upon in the docket. This information is in the form of studies. These studies have been subject to extensive scrutiny and peer review. To date no specific allegation has been made that the studies are clearly in error or that the data underlying them are the subject of fraud, scientific misconduct, or gross error going to the basic validity of the studies.[94] Instead, various commenters have merely stated their view that were the raw data behind these studies available, they would be able to better verify and assess the results reached in the studies.

As one commenter noted, ''In the absence of data on which EPA's proposal is based, [key scientific] issues remain shrouded in uncertainty and skepticism. The disclosure of the data would allow for robust scientific analysis and discussion of these issues.'' A similarly hypothetical concern is raised by another commenter who stated that ''seeing the data would clarify substantial questions of methodology'' and ''had the Harvard data been available, a far broader evaluation of the defects of the Harvard Studies would have been possible with the same expenditure of time and money.'' Yet, despite having spent ''in the neighborhood of a million dollars to duplicate and reanalyze the Harvard data set'' this commenter was unable to allege any particular defect in the methodology or results of these studies and noted instead that ''the track record to date suggests that the claimed associations to $PM_{2.5}$ and health effects would not have held up under such a broader evaluation.''

EPA is not required to await the results of such an inquiry before proceeding to regulate to protect human health and the environment. The concerns raised by the commenters regarding these studies remain hypothetical; the comments themselves raise no allegations of fraud, scientific misconduct or gross error that calls into question the fundamental validity of the studies. Given this fact, EPA does not agree with the commenters that reliance on these studies and/or a failure to place the underlying data in the docket constitutes an error, much less an error that is ''so serious and related to matters of such central relevance that there is a substantial likelihood that the rule would have been significantly changed.'' EPA is entitled to rely upon these studies and it has satisfied its obligation to provide the ''factual data'' upon which the proposed rule is based by placing these studies in the docket.

In fact, the concerns raised by the commenters ultimately boil down to a disagreement with EPA over the level of scientific certainty necessary to adopt the NAAQS revisions. In setting standards under the Clean Air Act, EPA is not required to resolve all scientific issues to the complete satisfaction of every interested party. As noted by the D.C. Circuit in *Lead Industries Association* v. *EPA,* 647 F.2d 1130, 1160 (D.C. Cir. 1980):

> To be sure, the Administrator's conclusions were not unchallenged; both LIA and the Administrator are able to point to an impressive array of experts supporting each of their respective positions. However, disagreement among the experts is inevitable when the issues involved are at the ''very frontiers of scientific knowledge,'' and such disagreement does not preclude us from finding that the Administrator's decisions are adequately supported by the evidence in the record. It may be that LIA expects this court to conclude that LIA's experts are right, and the experts whose testimony supports EPA are wrong. If so, LIA has seriously misconceived our role * * * . It is not our function to resolve disagreement among the experts or to judge the merits of competing expert views * * * . Cf. *Hercules, Inc.*, v. *EPA,* 598 F.2d 91, 115 (D.C. Cir. 1978) (''[c]hoice among scientific test data is precisely the type of judgment that must be made by EPA, not this court'').

[93] One commenter argued that EPA's failure to place the ''data'' in the docket was not an ''error'' but a ''refusal to comply with the clear language of the law that should be reviewed by the courts under section 307(d)(9)(C), rather than 307(d)(9)(D).'' As noted previously, EPA does not agree with this interpretation of section 307(d)(3) of the Act. Under applicable caselaw, the term ''data'' may include information in many forms, including studies that EPA has placed in the docket. See *Endangered Species Committee* v. *Babbitt,* 852 F. Supp. 32, 37 (D.D.C., 1994) (''data can come in many forms: it can be a scientific report, it can be graphs and tabulations * * * it can be raw numbers'').

[94] A number of commenters did argue these studies do not form a sufficient basis for EPA's decision to revise the NAAQS and that attempts to replicate these studies have not been universally successful. These same commenters also listed a number of hypothetical questions and issues that might be resolved through a review of the underlying data and suggested that before EPA may properly rely on these studies to revise the NAAQS, a variety of confounders (such as smoking) should also be ruled out by reviewing the data. As set forth more fully in Unit II. of this preamble, neither EPA nor CASAC agrees that any of these factors precludes reliance on the studies in question.

647 F.2d at 1160 (footnotes omitted).

The EPA's rationale for proposing to add a fine particle standard was detailed in the preamble to the proposed rule, most notably at 61 FR 65654–65662, December 13, 1996. This decision is based on the extensive review of the science and policy issues contained in the PM Criteria Document and Staff Paper; the CASAC concluded, after extensive review, that both of these documents were appropriate for use in decision making on standards. These documents contain a full discussion of both what is known about PM and the information gaps and uncertainties. Considering the full weight of the scientific evidence, including the uncertainties, the CASAC recommended that the Administrator adopt fine particle standards and a number of panel members based their support for a $PM_{2.5}$ standard on the following reasoning:

> [T]here is strong consistency and coherence of information indicating that high concentrations of urban air pollution adversely affect human health, there are already NAAQS that deal with all of the major components of that pollution except $PM_{2.5}$, and there are strong reasons to believe that $PM_{2.5}$ is at least as important as $PM_{10-2.5}$ in producing adverse health effects.

Wolff, 1996.

Given the consistency and coherence of the evidence that premature mortality and sickness occur in large numbers of Americans at concentrations permitted by the current standards, it would be irresponsible to delay action that would put more appropriate air quality goals into place based on the most recent scientific information. After a review of the comments submitted, the Agency's conclusion that it is appropriate to rely on the existing studies remains unchanged.

D. 1990 Amendments

Contrary to the view expressed in some public comments, the provisions of subpart 4 of Part D of Title I of the Act, enacted in 1990, do not preclude EPA from adopting $PM_{2.5}$ as an additional indicator for PM and establishing standards for $PM_{2.5}$. The provisions of subpart 4 of Part D of Title I of the Act simply do not limit EPA's clear authority under section 109 of the Act to revise the PM standards.

The basic contention is that because the provisions of subpart 4 of Part D of Title I of the Act refer to PM_{10}, they prohibit EPA from regulating any other type of PM, for example, by revising the existing NAAQS for PM by adopting an ambient air quality standard for $PM_{2.5}$. These provisions, however, do not lead to such a conclusion. Moreover, this view ignores provisions indicating that Congress believed that EPA could revise any existing NAAQS or adopt a new NAAQS.

At the outset, it should be noted that Congress expressly authorized EPA to revise any ambient air quality standard and to adopt a new NAAQS in section 109 of the Act. That section, which requires EPA to review and revise, as appropriate, each NAAQS every five years, contains no language expressly or implicitly prohibiting EPA from revising a NAAQS or adopting a new NAAQS. If Congress had intended to preclude EPA from reviewing and revising a NAAQS or adopting a new NAAQS, which are part of EPA's fundamental functions, Congress would have specifically done so. Clearly, Congress knew how to preclude EPA from exercising otherwise existing regulatory authority and did so in other instances. See section 202(b)(1)(C) of the Act (expressly precluding EPA from modifying certain motor vehicle standards prior to model year 2004); section 112(b)(2) of the Act (preventing EPA from adding to the list of hazardous air pollutants any air pollutants that are listed under section 108(a) of the Act unless they meet the specific exceptions of section 112(b)(2) of the Act); section 249(e)(3), (f) and section 250(b) (limiting EPA's authority regarding certain clean-fuel vehicle programs). No such language was included either in section 109 of the Act or elsewhere in the Act and no such implication may properly be based on the provisions of subpart 4 of Part D of Title I of the Act.

Second, other provisions of the Act expressly contemplate EPA's ability to promulgate a new or revised NAAQS, and provide no indication that such ability is limited to standards other than those whose implementation is the subject of subparts 2, 3 and 4 of Part D of Title I of the Act. For example, section 110(a)(2)(H)(i) of the Act provides that SIPs are to provide for revisions ''from time to time as may be necessary to take account of revisions of such national primary or secondary ambient air quality standard * * * .'' Section 107(d)(1)(A) of the Act provides a process for designating areas as attainment, nonattainment, or unclassifiable ''after promulgation of a new or revised standard for any pollutant under section 109 * * * .'' Section 172(e) of the Act addresses modifications of national primary ambient air quality standards. Finally, section 172(a)(1) of the Act expressly contemplates that EPA may revise a standard in effect at the time of enactment of the 1990 Clean Air Act Amendments. Section 172(a)(1)(A) of the Act provides EPA with authority to classify nonattainment areas on or after the designation of an area as nonattainment with respect to ''any revised standard, including a revision of any standard in effect on the date of the enactment of the Clean Air Act Amendments of 1990.'' Plainly, Congress had no intention of prohibiting EPA from revising any of the ambient standards in effect at the time of the enactment of the 1990 amendments.

Third, the provisions of subpart 4 of Part D of Title I of the Act do not support the contention that they somehow preclude EPA from exercising its authority to adopt a revised PM NAAQS based on a metric other than PM_{10}. The fact that Congress laid out an implementation program for the PM standard existing at the time of the 1990 amendments in no way suggests that Congress intended to preclude EPA from exercising the authority it provided EPA to revise the NAAQS when the health data on which EPA bases such decisions warranted a change in the standard.

The fact that Congress drafted subpart 4 of Part D of Title I of the Act in 1990 to specify the implementation regime for the PM standard then in effect, a PM_{10} standard, in terms that explicitly refer to PM_{10} in no way suggests that Congress meant to preclude EPA from adopting a PM standard based on another metric if scientific information supported such a change. Obviously, PM_{10} was the standard in existence in 1990 and Congress drafted subpart 4 of Part D of Title I of the Act, the purpose of which was to delineate an implementation regime for that standard, in terms of that standard. There is simply no language in subpart 4 of Part D of Title I of the Act that limits EPA's ability to establish a different PM standard if such a standard were warranted under section 109 of the Act or indicates any implicit intent on the part of Congress to limit EPA's authority under section 109 of the Act in such a way. Subpart 4 of Part D of Title I of the Act simply does not speak to the question of whether EPA may establish a PM standard based on a different metric. In addition, section 107(d)(4) of the Act, the only provision outside of subpart 4 of Part D of Title I of the Act invoked as a basis for the view that the Act prohibits EPA from adopting a $PM_{2.5}$ standard, does not support that view. That provision simply preserved pre-existing designations for ''total suspended particulates,'' the PM metric utilized prior to PM_{10}, for certain purposes. It provides no suggestion that Congress intended to prohibit EPA from adopting

a metric other than PM_{10}. Indeed, if anything, it indicates that Congress was fully aware that EPA had previously changed the PM metric used in the PM NAAQS and confirms the view that Congress would have explicitly barred EPA from changing the metric had it intended to do so.

Finally, for the reasons stated in this unit, EPA's analysis of its ability to implement a $PM_{2.5}$ standard under the provisions of subpart 1 of Part D of Title I does not support the view that Congress prohibited EPA from promulgating such a standard. Congress clearly specified an approach to the implementation of the PM_{10} standard in the provisions of subpart 4 of Part D of Title I of the Act. The EPA believes that the clear and express linkage of that approach to the PM_{10} standard indicates that a different PM standard should be implemented under the general principles of subpart 1 of Part D of Title I of the Act. That Congress directed specifically how EPA and the States should implement the PM_{10} standard does not carry with it the implication that Congress intended to prohibit EPA from exercising its otherwise clear and express authority to adopt a PM standard based on a different metric in order to carry out one of its fundamental missions, the establishment of ambient air quality standards to protect public health with an adequate margin of safety. It is entirely reasonable and logical for Congress to, on the one hand, specify an implementation regime for the PM standard in effect at the time of enactment of the 1990 amendments, but, on the other hand, leave EPA free to exercise the authority provided it by Congress in section 109 of the Act to adopt a new or revised standard when EPA determined that such a standard was needed to protect public health with an adequate margin of safety. Congress explicitly required EPA to review and revise as appropriate the NAAQS every five years. If Congress did not intend for EPA to revise the NAAQS when warranted, it would not have required EPA to review and revise them. If Congress had intended to prohibit EPA from exercising such a fundamental authority it would have clearly specified, as it did in other instances, that EPA could not do so.

V. Revisions to 40 CFR Part 50, Appendix K—Intrepretation of the PM NAAQS

Because the revocation of the existing PM_{10} standards will become effective at a later date (as discussed in Unit VII. of this preamble), EPA is retaining 40 CFR part 50, Appendix K, although it is being published today in revised format to conform with the format of the other appendices in this part. A new Appendix N to 40 CFR part 50 explains the computations necessary for determining when the primary and secondary $PM_{2.5}$ and PM_{10} standards being adopted today are met. The discussion in this unit sometimes refers to the contents of the new Appendix N as revisions to Appendix K, so as to highlight how the new Appendix N differs from the current Appendix K.

Key elements of the new 40 CFR part 50, Appendix N, particularly as they differ from those of Appendix K, are outlined in this unit.

A. $PM_{2.5}$ Computations and Data Handling Conventions

As discussed in Unit II.E. of this preamble, the form of the annual $PM_{2.5}$ standard is a spatially averaged annual mean averaged over 3 years, and the form of the 24-hour $PM_{2.5}$ standard is a 98^{th} percentile concentration averaged over 3 years.

With regard to the annual $PM_{2.5}$ standard, the EPA proposed a form expressed as the annual arithmetic mean, averaged over 3 years and spatially averaged over all designated monitoring sites to represent population exposures. As discussed in Unit II.E.1. of this preamble, the form of the annual $PM_{2.5}$ standard has been clarified to make explicit that implementing agencies have the flexibility to base comparison of the standard level with measured values from either a single community-oriented site or an average of measured values from such monitors within the constraints enumerated in 40 CFR part 58. The new Appendix N of 40 CFR part 50 reflects this clarification. The spatial average, if used, is to be carried out using data from monitoring sites designated in a State PM Monitoring Network Description in accordance with the provisions of 40 CFR part 58.

Also, the EPA proposed that, for spatial averaging, the requirements for 3 years of data for comparison with the standard be fulfilled by the spatial averaging network as a whole, not by individual monitors within the network. The EPA received comments regarding the application of the 75 percent data completeness requirement to spatial averaging. The commenters stated that the inclusion or exclusion of a site not meeting the data completeness requirements from a spatial average, based on the level of the single site average, would bias the spatial average for that year. The EPA has responded to the comment by demonstrating in Example 1 in 40 CFR part 50, Appendix N the application of the data completeness criterion that is consistent with a spatially averaged network. Specifically, the application of the data completeness requirement has been altered in the example if a particular site has quarters in a year that do not meet the minimum data completeness requirement. Instead of comparing a site's annual average to the level of the standard to decide whether or not to keep the site in the calculations, the annual average for all the sites (the spatial average) is compared to the level of the standard. If the spatial average is above the level of the standard, the site is kept in the calculations. If it is below, the site is omitted from the calculations.

The EPA also proposed that averaging over calendar quarters be retained for the annual average form of the standard. Although several commenters stated that the step of calculating quarterly averages to obtain the annual average was unnecessary, the EPA maintains that quarterly averages are important to ensure representative sampling in areas with extreme seasonal variation.

Regarding the 75 percent data completeness requirement, the proposal stated that a given year meets data completeness requirements when at least 75 percent of the scheduled sampling days for each quarter have valid data, and high values measured in incomplete quarters shall not be ignored but shall be included if their value causes the annual calculation to be above the level of the standard. Some commenters felt that this treatment was unfair in that measured data below the standard in incomplete quarters are not retained. In addition, the commenters felt that this could create a bias where a single sample could inflate an annual average to a level above the standard. The EPA agrees and has incorporated in 40 CFR part 50, Appendix N the following provisions.

(1) A statement has been added that less than complete data may be used in certain cases subject to the approval of the appropriate Regional Administrator in accordance with EPA guidance for dealing with less than complete data. This statement was considered necessary for those situations where measured data and air quality analyses would indicate that the area met or did not meet the standard although it did not exactly meet the data completeness requirements.

(2) A provision has been added that a minimal amount of data is needed before the requirement to retain high values in an incomplete quarter comes into effect for the annual standards. Sites with at least 11 samples but less than 75 percent data completeness in a quarter will have to include high values

if they result in calculated values which are above the level of the standard. This provision is based upon the change in sampling frequency set forth in the revisions to 40 CFR part 58 which effectively doubles the minimum sampling frequency from 1-in-6 day sampling to 1-in-3 day sampling. The data completeness requirement for the annual form of the standard under the original 1-in-6 day sampling schedule is equivalent to a minimum of 37.5 percent under the new sampling schedule of 1-in-3 days. This is equivalent to a minimum of 11 samples in each quarter. Therefore, a minimum of 11 samples in a quarter should be sufficient for an annual average above the level of the standard to be used under the new sampling schedule.

(3) In sharp contrast, this minimum requirement was considered unnecessary for the 24-hour form of the standard when the 98th percentile is above the level of the standard. That is, for a site with a 98th percentile above the level of the standard that does not meet the 75 percent data completeness requirement, the 98th percentile would be equivalent to the maximum or second maximum daily concentration in that year. While adding more data samples up to the minimum data completeness requirement of 75 percent could help to ensure that the second maximum value (rather than the maximum value) corresponds to the 98th percentile, this difference is not considered significant enough to require some minimal number of data samples when dealing with the form of the 24-hour standard.

With regard to the 24-hour $PM_{2.5}$ standard, the proposed revision to 40 CFR part 50, Appendix K defined the 98th percentile as the daily value out of a year of monitoring data below which 98 percent of all values in the group fall. The calculation of the percentile form has been revised to reflect general comments that the form of the standard and its calculation should be simplified. The EPA maintains that the revised calculation is consistent with the definition of the percentile being that number below which a certain percent of the data fall.

Regarding the expression of the annual standard to the nearest 0.1 μg/m^3 and the 24-hour standard to the nearest 1 μg/m^3, virtually no commenters disagreed with the EPA's proposed approach. The few that did, however, took issue with the overall stringency of the standards, not the rationale discussed in the proposal. The EPA maintains its position that instrument sensitivity and the number of measured values used in calculating the values to be compared to the standard, as discussed at length in the proposal, point to keeping the expressions of the standards stated in this unit.

B. PM_{10} Computations and Data Handling Conventions

As discussed in Unit II.G. of this preamble, the EPA proposed retaining the current annual arithmetic mean, averaged over 3 years, as the form of the annual PM_{10} standard, and changing the form of the 24-hour PM_{10} standard to a 98th percentile value form, averaged over 3 years. As discussed in Unit II.G. of this preamble, the form of the daily PM_{10} standard has been revised to a 99th percentile instead of the 98th percentile, and the related calculations have been revised accordingly. The same revision described above in Unit V.A. of this preamble to simplify the formula used to calculate the percentile form of the 24-hour $PM_{2.5}$ standard also applies to the PM_{10} 99th percentile calculation.

The revisions made to the annual and 24-hour $PM_{2.5}$ standards regarding the 75 percent data completeness requirement also apply to the annual and 24-hour PM_{10} standards. Appendix N of 40 CFR part 50 reflects this change.

As with the $PM_{2.5}$ standards, the EPA maintains its position that instrument sensitivity and the number of measured values used in calculating the values to be compared to the standard, as discussed in detail in the proposal, point to keeping the expressions of the standards to the nearest 1 μg/m^3 for the annual standard and to the nearest 10 μg/m^3 for the 24-hour standard.

C. Changes That Apply to Both $PM_{2.5}$ and PM_{10} Computations

In the proposal, the EPA stated that revisions to 40 CFR part 50, Appendix K would not address the treatment of exceptional events data, which are considered part of the standards implementation process. Since several commenters mentioned the handling of these events in conjunction with the proposed revisions to Appendix K, the EPA has addressed this concern in Appendix N of 40 CFR part 50, which states that whether to exclude, retain, or make adjustments to data affected by uncontrollable or natural events is subject to the approval of the appropriate Regional Administrator.

Comments were also received expressing the desire of some areas to conduct seasonal sampling, reducing the frequency of monitoring during a period of expected low concentrations to save resources. The proposed revision to 40 CFR part 50, Appendix K did not prohibit this course of action, and referred matters of sampling frequency to 40 CFR 58.13. For clarification, 40 CFR part 50, Appendix N adds that exceptions to specified sampling frequencies, such as a reduced frequency during a season of expected low concentrations, shall be subject to the approval of the appropriate Regional Administrator.

VI. Reference Methods for the Determination of Particulate Matter as PM_{10} and $PM_{2.5}$ in the Atmosphere

A. Revisions to 40 CFR Part 50, Appendix J—Reference Method for PM_{10}

Because the revocation of the existing PM_{10} standards will become effective at a later date (as discussed in Unit VII. of this preamble), EPA is retaining Appendix J in its current form. A new Appendix M to 40 CFR part 50 establishes the reference method for measuring PM_{10} in the ambient air for the revised PM_{10} standards. The discussion in this unit sometimes refers to the contents of the new Appendix M as revisions to Appendix J, so as to highlight how the new Appendix M differs from the current Appendix J. As discussed below, the only revision to the Reference Method for PM_{10} relates to the calculation of the volume of air sampled.

During the course of this standards review, EPA has received a number of comments regarding the appropriateness of the current practice of adjusting measured PM_{10} concentrations to reflect standard conditions of temperature and pressure (25° C and 760 mm Hg, respectively), as required by 40 CFR part 50, Appendix J. The practice was originally adopted to provide a standard basis for comparing all pollutants measured in terms of mass per unit volume (e.g., μg/m^3). As EPA has reviewed the ambient standards for gaseous pollutants, however, technical changes have been made to express them on a pollutant volume/air volume basis (i.e., ppm) that is insensitive to differences in altitude and temperature. Such an approach is not applicable to particulate pollutants. The question arises whether continuing the past practice of making temperature and pressure adjustments for PM is appropriate or necessary.

Information in the Criteria Document on the health and welfare effects of PM provides no clear basis for making such adjustments. Recent health effects studies have been conducted in cool and warm climates, and in cities at high altitude, e.g., Denver, as well as near sea level, e.g., Philadelphia (U.S. EPA, 1996a). These studies provide no evidence that risk associated with PM exposures is affected by variations in

altitude. Accordingly, any effect that would be accounted for by temperature and pressure adjustments would be below the detection limits of epidemiological studies. While extremes of altitude might be expected to increase the delivered dose of PM in those not acclimatized to such locations, the dosimetric studies summarized in the Criteria Document provide no clear support for any quantitative adjustment to standard conditions. With respect to welfare effects, visibility is directly related to the actual mass of fine particles in the atmosphere. Adjustment of PM concentrations collected at higher altitudes to standard conditions would therefore lead to an overstatement of the effect of PM on visibility in such locations. Similarly, there is no evidence in the Criteria Document suggesting that effects on materials damage and soiling are dependent on altitude.

Based on this assessment, EPA proposed to delete the requirement to adjust PM_{10} concentrations to standard conditions of temperature and pressure from 40 CFR part 50, Appendix J for the revised standards and to make corresponding revisions in 40 CFR 50.3. Comments received on this issue were divided. A number of commentors supported EPA's proposal for the reasons set forth above. A few States opposed the change because the lack of adjustment for very cold temperature in areas near sea level could make the standard more stringent. Some commentors were concerned that the proposed change would relax protection afforded for areas at high altitude. A few commentors expressed concern that ''sojourners'' who visit high altitude area would have higher ventilation rates and receive reduced protection as compared to local residents whose ventilation patterns were more adapted to these conditions.

The EPA does not believe that the localized comparisons regarding increased or decreased stringency of standards relative to the proposed change are an appropriate rationale for keeping the current adjustment for temperature and pressure. The issue is whether the available scientific evidence on the health and welfare effects of PM provides a basis for continuing with the traditional adjustments. The comments with respect to sojourners at altitude are relevant, but this issue was considered in reaching the proposed decision. Furthermore, commentors provided neither laboratory nor epidemiologic evidence that would support their theoretical concerns regarding increased annual or 24-hour PM effects at altitudes typical of mountainous urban areas in the United States.

Based on its assessment of the available evidence and public comments, EPA concludes that a continuation of the practice of adjusting PM_{10} concentrations to standard conditions of temperature and pressure is not warranted or appropriate. Accordingly, this requirement is not included in 40 CFR part 50, Appendix M and corresponding revisions are made in 40 CFR 50.3. In addition, EPA is also incorporating the proposed minor modifications to 40 CFR part 50, Appendix J in Appendix M.

B. 40 CFR Part 50, Appendix L - New Reference Method for $PM_{2.5}$

1. *Introduction.* A new reference method for the measurement of fine particles (as $PM_{2.5}$) in the ambient air has been developed for the primary purpose of determining attainment of the new $PM_{2.5}$ standards. The method is described in the new 40 CFR part 50, Appendix L, and joins the other reference methods (or measurement principles) specified for other criteria pollutants in other appendices to 40 CFR part 50.

In developing the proposed new reference method for $PM_{2.5}$, EPA staff consulted with a number of individuals and groups in the monitoring community, including instrument manufacturers, academics, consultants, and experts in State and local agencies. The approach and key specifications were submitted to the CASAC Technical Subcommittee for Fine Particle Monitoring, which held a public meeting to discuss the proposed new reference method for $PM_{2.5}$ and related monitoring issues on March 1, 1996. Comments on the proposed method were provided orally and in writing by interested parties. The Technical Subcommittee indicated their overall satisfaction with the method in a letter (Price, 1996) forwarded by CASAC to the Administrator.

On December 13, 1996, EPA proposed the new 40 CFR part 50, Appendix L at 61 FR 65676 for public comment. The proposal described in detail the approach taken and the design specifications and performance requirements for the new $PM_{2.5}$ sampler. On January 14, 1997, EPA held a public hearing on the proposed new 40 CFR part 50, Appendix L and associated 40 CFR parts 53 and 58 requirements.

2. *Basic reference method approach.* In addition to the primary purpose of the new $PM_{2.5}$ reference method (determining attainment of the standards), EPA considered a variety of possible secondary goals and objectives that the $PM_{2.5}$ reference method might also fulfill. Subsequently, various alternative $PM_{2.5}$ measurement techniques were evaluated. From this analysis, EPA proposed to base its $PM_{2.5}$ reference method on a conventional type sampler that collects 24-hour integrated $PM_{2.5}$ samples on a 47 mm Teflon filter that is subsequently moisture and temperature conditioned and analyzed gravimetrically. The sampler is a low volume sampler that operates at a flow rate of 1 cubic meter per hour, for a total sample volume of 24 m^3 for the specified 24-hour sample collection period. The sampler is easy to operate, operates over a wide range of ambient conditions, produces a measurement that is comparable to large sets of previously collected PM data in existing databases, and provides a physical sample that can be further analyzed for chemical composition.

3. *Public comments and responses*—

a. *Sampler design.* The EPA received many general comments concerning the proposed sampler design. Commenters suggested the use of a different indicator, use of a different size cut, inclusion of additional constituents (e.g., acid aerosols, carbon, metals, and semi-volatiles), and/or use of a multi-filter method. Early in the development process, design decisions were based on public input and the advice of CASAC on these and other basic design issues. Other factors affecting the basic design of the method were the need for historical continuity, high measurement precision, and simplicity of operation, all in response to current national monitoring objectives and available resources. In selecting the basic measurement approach, substantial weight was given to maintaining comparability to $PM_{2.5}$ samplers, such as the ''dichotomous sampler,'' that were widely used to obtain the data upon which the new standards are based. Given this objective, EPA concludes that the conventional PM measurement approach is appropriate and will provide $PM_{2.5}$ measurements that are comparable to the air quality data used in the health studies that provide the basis for the $PM_{2.5}$ standards.

Although the sampler is conventional in configuration, its design is much more sophisticated than that of previous PM samplers. This more sophisticated sampler, together with improved manufacturing and operational quality assurance, is necessary to achieve the more stringent data quality objectives established for $PM_{2.5}$ monitoring data. To meet precision requirements, the critical mechanical components of the inlet, particle size separator, downtube, and upper portion of the filter holder

are specified by design. All other aspects of the sampler are specified by performance-based specifications.

Several commenters felt that the portions of the sampler that were specified by design would stifle further improvements and innovations. Although the EPA specifies methods by performance whenever possible, for the $PM_{2.5}$ reference method, development of adequate performance specifications for inlet aspiration and particle size discrimination would have been a very difficult, costly, lengthy, and problematic process. Moreover, manufacturer testing of proposed inlet and particle size discrimination devices against such performance specifications would require elaborate specialized facilities and would be extremely costly. For these reasons, the EPA believes that specification of these critical components by design is a prudent and very cost-effective way to ensure good inter-manufacturer and intra-manufacturer precision of the $PM_{2.5}$ measurements. Therefore, these components are specified by design, and other aspects of the sampler are specified by performance, as proposed. Innovations and improved samplers or measurement methods are encouraged and provided for as Class II and III equivalent methods (see 40 CFR part 53).

b. *Inlet and impactor design.* Several commenters addressed the inlet design, noting that the inlet could allow entrance of precipitation and possibly insects. In fact, the inlet selected for the sampler has been used effectively for many years to obtain many of the $PM_{2.5}$ measurements that formed the basis of the epidemiological studies. While EPA acknowledges that there have been some reports of intrusion of precipitation, the Agency believes the problem is relatively minor. Nevertheless, a modification of the inlet has been developed to further reduce the possibility of precipitation (and possibly small insects) reaching the sample filter to damage the $PM_{2.5}$ sample. Extensive wind tunnel tests have shown no significant compromise in the $PM_{2.5}$ aspiration performance of the modified inlet.

In addition, a new provision has been added, in 40 CFR part 50, Appendix L, section 7.3.8, to require that the sampling air entrance of the inlet be at a height of 2 ± 0.2 meters above the supporting surface to help ensure homogeneous air samples when collocated samplers of different types are operated simultaneously.

Other commenters addressed the sharpness of the size cut and how it is obtained, e.g., whether more than two stages should be used and what size cut should be used for each stage. These aspects were carefully considered in selecting the sampler configuration. The selection by EPA of the previously used PM_{10} inlet established the size cut for the first stage, and the second stage was designed to be simple, reliable, and low in cost for user agencies. In EPA's estimation, the advantages of this configuration outweigh any modest advantage that might have been gained by designing a new inlet/separation configuration that would further refine the cut points at each of two (or more) stages.

A few commenters questioned whether the inlet was wind speed dependent at high wind speeds. The selected inlet has been shown to perform well up to 24 km/hr with 10 µm aerosols and is expected to perform well at higher speeds with 2.5 µm aerosols. The EPA again determined that the advantages of using the selected inlet outweighed the possible minor improvement in wind-speed characteristics that might have been obtained by a newly-designed inlet.

Some commenters felt that other types of particle discrimination techniques such as cyclones and virtual impactors, should be allowed. Again, these alternatives were evaluated previously and the specified inlet and impactor were determined to best meet the various objectives of the sampler. However, EPA has provided for considerations of other particle size selection techniques or devices for approval if incorporated into candidate equivalent methods for $PM_{2.5}$.

Several commenters addressed the impactor design, noting that the impactor should be changed to sharpen the size-cut characteristic, to address concerns regarding possible contamination and/or performance loss due to impactor oil, and to improve ease of access to service. To address the first concern, the initial prototype impactor has been modified slightly to sharpen its size-cut. The current impactor is designed to lower cost and to optimize cut sharpness, loading capacity, manufacturing simplicity, manufacturing quality control, serviceability, and reliability. A report containing the penetration efficiency of the impactor is available in Docket No. A-95-54. With regard to impactor oil concerns, the impactor oil selected has a very low vapor pressure, and testing has indicated no contamination of the sample filters with impactor oil. The EPA believes that the impactor design is as accessible as possible, given the design objectives. Some flexibility may be allowed for manufacturers to develop improved closure devices or other external modifications. Proper maintenance will, of course, be very important and will be stressed in the associated operator instruction manuals and in other training and guidance materials. The EPA has been performing field and laboratory tests that will provide detailed guidance for all necessary preventive maintenance. Proper installation procedures for the oil and the impactor filter, as well as all other maintenance requirements, will be available in the quality assurance procedures and guidance contained in the new section 2.12 of Appendix L to be added to EPA's Quality Assurance Handbook for Air Pollution Measurement Systems (EPA/600/R-94/038b).

c. *Anodized aluminum surface.* All internal surfaces exposed to sample air prior to the filter are required to be anodized aluminum as stated in 40 CFR part 50, Appendix L, section 7.3.7. A few commenters expressed concern that the anodized aluminum surfaces in high volume PM_{10} samplers have shown substantial pitting, particularly in the venturi flow control device. The anodized aluminum surfaces are required in the $PM_{2.5}$ sampler to maintain comparability to previously used samplers. The EPA believes that the much lower flow rate in the $PM_{2.5}$ sampler will greatly reduce the pitting tendency, and the active flow control in the $PM_{2.5}$ sampler is not dependent on the physical dimensions of a critical orifice as it is in a venturi flow control device.

d. *Filter for $PM_{2.5}$ sample collection.* The proposed reference method called for the sample to be collected on a 47 mm Teflon filter. Many of the comments received on the measurement method concerned the proposed filter medium and its performance. Commenters expressed concerns with the use of Teflon filters and with the selection of a single-filter method. Several commenters recommended that alternative filter media be allowed, in most cases to support speciation and/or to allow the capture of all PM components. Other comments noted potential advantages of other media in operating characteristics or chemistry requirements. Operational concerns expressed about Teflon filters included tearing, possible loss of integrity, and high cost. Other concerns were that Teflon is generally not conducive to carbon analysis, and that Teflon filters may not hold deposited PM. Many commenters recommended use of a multi-filter sampler to support chemical speciation in addition to compliance determination.

To address some of these general concerns about the performance of the specified filter material, some minor refinements to the filter specifications concerning the filter diameter and the filter support ring have been made to ensure proper performance of the filter in the specified filter holder. Additional clarifications have been made to the maximum moisture pickup and the filter weight stability requirements. Although Teflon may preclude certain chemical analyses (e.g., elemental and organic carbon), the EPA believes that Teflon filter material is the best overall choice to meet the objectives of compliance monitoring and to provide good measurement precision. Other filter media are likely to provide reduced gravimetric precision and preclude more types of subsequent chemical analysis. Additional or alternative samplers or filter types can be considered as candidate equivalent methods under 40 CFR part 53 and can be used for non-compliance monitoring, where necessary.

Compliance monitoring based on mass concentration of $PM_{2.5}$ is the primary objective of the reference method. Multi-filter capability would have substantially increased the cost and complexity of the sampler. However, multi-filter samplers can be considered as candidate equivalent methods. In addition, multi-filter samplers can be used as special purpose monitors (SPMs) to perform characterization studies, develop control strategies, and conduct other special studies as has been done previously for PM_{10}.

In response to numerous comments received on 40 CFR part 50, Appendix L and on the provisions of 40 CFR part 58 regarding the need for chemical speciation, the EPA is assigning a high priority to a chemical speciation trends network through section 105 of the Act grant allocation program and will issue guidance describing the monitoring methods and scenarios under which speciation should be performed. The program will incorporate additional $PM_{2.5}$ samplers that allow for the simultaneous collection of aerosols on multiple filter media.

The associated requirement for archiving filters has been removed from 40 CFR part 50, Appendix L, section 10.17 and relocated to 40 CFR part 58, Appendix A. This change has been made because this is a supplemental monitoring requirement and not an integral part of the reference method for determining compliance with the $PM_{2.5}$ NAAQS.

Provisions of 40 CFR part 50, Appendix L have been clarified to apply not only to a single-sample sampler, but also to a sequential-sample sampler, provided that all specifications are met and no deviations, modifications, or exceptions are made to the inlet, downtube, impactor, or the upper portion of the filter holder. Samplers that have minor changes or modifications in these components, have changes that alter the aerosol's flow path, or contain other significant deviations will be required to meet the requirements of Class I equivalent methods, in the amendments to 40 CFR part 53. Further, a provision has been added to require that sequential sample filters stored in a sequential sampler be adequately covered and protected from contamination during storage periods in the sampler.

A few commenters expressed concern about who must carry out filter tests to determine if they meet the filter specifications. In response, the filter specifications have been clarified to indicate that filter manufacturers should generally carry out most or all of the filter performance tests in order to certify that their filters meet the filter specifications for the $PM_{2.5}$ reference method. In addition, EPA conducts acceptance tests on filters procured for NAMS/SLAMS networks prior to distribution to State and local agencies.

Some commenters requested additional information on the requirement that an ID number be attached to each filter. Preliminary information indicates that it is not practical at this time for either filter manufacturers or users to print an ID number directly on the filter. However, EPA is continuing to pursue this goal. In the meantime, alternative means, such as attaching an appropriate ID number to the filter's storage container, will be necessary. Additional details and possible alternative filter identification methods will be provided in new section 2.12 of the Quality Assurance Handbook for Air Pollution Measurement Systems.

e. *Filter handling/weighing/conditioning requirements.* Many commenters felt that the filter handling requirements for collected $PM_{2.5}$ samples were too burdensome. However, handling of the exposed filter between retrieval from the sampler and commencement of the conditioning period is expected to be one of the most significant sources of $PM_{2.5}$ measurement variability. Thus, EPA concludes that specific requirements for this activity are necessary, and this position was supported by several commenters.

Some commenters felt that the samples should be kept cold until analysis to prevent volatile losses. In response to this concern, the restriction on the maximum temperature exposure for collected samples has been reduced from 32 to 25° C, and a recommendation has been added for sampler operators to keep the samples as cool as practical between retrieval from the sampler and delivery to the conditioning environment. Further, the length of time permitted between retrieval of the filter and post-collection weighing is increased from 10 to 30 days, provided that the sample is maintained at 4° C or less between retrieval and the start of the conditioning period. The new section 2.12 of the Quality Assurance Handbook for Air Pollution Measurement Systems will provide guidance and techniques for keeping samples cool during this period and may suggest devices to document maximum temperature exposure of the sample.

Commenters also requested additional specifications and guidance for field blanks. The EPA will provide additional clarification and detailed procedures and guidance regarding field blanks in the new section 2.12 of the Quality Assurance Handbook for Air Pollution Measurement Systems.

Other commenters felt that the filter weighing requirements were too restrictive. Because filter weighing is one of the most significant sources of $PM_{2.5}$ measurement variability, specific requirements and restrictions are deemed necessary. However, in response to some of the concerns expressed, the proposed requirement that both pre- and post-weighings be carried out by the same analyst has been reduced to a non-mandatory recommendation. Detailed recommendations and guidance on filter weighing, based on information obtained in current field tests, will be provided in the new section 2.12 of the Quality Assurance Handbook for Air Pollution Measurement Systems.

Several commenters questioned the filter conditioning requirements, with some requesting a lower humidity range. Since humidity can profoundly affect the weight of the $PM_{2.5}$ on the filter, EPA maintains that filter conditioning requirements need to be tight to control measurement variability and to ensure satisfactory precision. But in response to at least one of the concerns, the filter conditioning humidity requirement has been changed to allow conditioning at a relative humidity within ±5 RH percent of the mean ambient humidity during sampling (down to a minimum of 20 RH percent) for samples collected at average ambient humidities lower than 30

percent. The EPA will provide further details on filter conditioning controls in the new section 2.12 of the Quality Assurance Handbook for Air Pollution Measurement Systems.

f. *Sampler performance requirements.* Several commenters addressed sampler performance requirements, including sampler flow control specifications, filter temperature control, sampler performance under extreme conditions, and data reporting. In response to concerns that various sampler flow control specifications are too tight, EPA contends that good flow control is necessary to maintain uniform sampling, to ensure correct particle size discrimination, and to control measurement variability. Sampler manufacturers have been able to meet the specified flow control requirements, and field studies to date confirm that prototype samplers are able to meet these flow control requirements.

In response to comments about the ambient temperature plus 3° C filter temperature control requirement, EPA believes that fairly tight control of the sample filter temperature is necessary to minimize losses of semi-volatile components over a wide temperature range, and tight temperature control has been strongly recommended by the CASAC. Monitoring of the filter temperature difference from ambient temperature is necessary to verify that the sampler filter temperature control is functioning properly. Testing to date indicates that the proposed 3° C (above ambient temperature) limit is somewhat difficult to meet; however, a 5° C limit can be reasonably met. Therefore, the filter temperature control requirement has been relaxed slightly from 3° C to not more than 5° C above the concurrent ambient temperature. Ambient and filter temperature sensors will require periodic calibration or verification of accuracy. In response to a frequent comment, the method has been clarified to indicate that exceedance of the filter temperature difference limit would not necessarily invalidate the sample.

In response to concerns about the performance of the sampler under extreme weather conditions (e.g., high or low temperatures, low pressures, high winds, high or low humidity, fog, dust storms), the EPA has established sampler specifications that are intended to cover reasonably normal environmental conditions at about 95 percent of expected monitoring sites. Qualification test requirements in 40 CFR part 53 address most, if not all, of these operational requirements. Specification of the sampler performance for sites with extreme environmental conditions would substantially raise the cost of the sampler for other users, most of whom do not require the extra capability. Users requiring operation of samplers under extreme conditions are encouraged to develop supplemental specifications for modified samplers to cover those specific conditions. Sampler manufacturers have indicated a commitment to respond to the need for modified samplers for such extreme conditions.

Although concerns were expressed that the amount of data required to be reported from each sampler is excessive, EPA stresses that only a portion of the data collected by the sampler needs to be reported to AIRS. These limited data reporting requirements (i.e., ambient and filter temperature, barometric pressure, sample volume, variation in sample run flow rate) are important to establish or verify the reliability and confidence of the $PM_{2.5}$ measurements and to aid in utilization of those data. The substantial amount of additional data generated by the sampler are of use to the site operator to provide confirmation of a given sample's validity, and to aid in troubleshooting should outlier measurements appear in the monitoring data. A variety of current electronic devices and systems may be used to acquire and handle the data, and these devices can easily accommodate the amount of data required to be reported, as well as the additional, optional data. Printers, modem connections, and alternative data output connections or devices are not precluded.

4. *Additional changes.* Additional clarifying changes have also been made throughout 40 CFR part 50, Appendix L, based on comments received or recently obtained field test information. In 40 CFR part 50, Appendix L, section 3.1, the lower concentration of the method has been revised from 1 to 2 $\mu g/m^3$, based on the results of field blanks associated with available field test data. In 40 CFR part 50, Appendix L, section 3.3, the sample period specification has been augmented to clarify that a measured $PM_{2.5}$ concentration for a sample period less than 23 hours that is greater than the NAAQS level(s) is to be considered a valid measurement for comparison to the NAAQS, even though not valid for other purposes. Sections 4 (Accuracy) and 5 (Precision) have been revised to properly reflect associated changes to the data quality and method performance assessment requirements set forth in 40 CFR part 58, Appendix A.

A provision has been added in 40 CFR part 50, Appendix L, section 7.4.17 to require sampler manufacturers to make available computer software to input sampler output data and translate the data into a standard spreadsheet format (since no specific format is specified for output of the sample data acquired by the sampler).

The requirements for the sampler to display current flow rate, temperature, filter temperature, and barometric pressure readings have been changed to require updating of these readings at least every 30 seconds. This change is based on operational experience of prototype samplers in 40 CFR part 50, Appendix L, section 7.4.5.1, and will make it easier for the operators to perform status checks and calibrations. In 40 CFR part 50, Appendix L, section 7.4.8.1, the requirements for the ambient temperature sensor have been changed to specify an external sensor with a passive sun shield, to provide better uniformity in the ambient temperature measurements among different types of reference method samplers. The reference method has also been clarified to indicate that $PM_{2.5}$ samples for which the sampler reported an out-of-specification (FLAG) occurrence during or after the sample period are not necessarily invalid, and that such samples should be reviewed by a quality assurance officer (40 CFR part 50, Appendix L, section 10.12). Finally, a new reference has been added in section 13 of the Act to provide applicable standards for meteorological measurements and measurement systems.

5. *Decision on 40 CFR part 50, Appendix L.* After fully considering the public comments on the proposed new reference method for $PM_{2.5}$, EPA has concluded that the proposed design and performance specifications for the reference sampler, with the modifications discussed in this unit, will achieve the design objectives set forth in the proposal and outlined above. Therefore, EPA is adopting the sampler and other method requirements specified in 40 CFR part 50, Appendix L as the reference method for measuring $PM_{2.5}$ in the ambient air.

Since proposal, a series of field tests have been performed using prototype samplers manufactured in accordance with the proposed design and performance specifications. The results of these field tests confirm that the prototype samplers perform in accordance with design expectations. Operational experience gained through these field tests did, however, identify the need for minor modifications as discussed above in this unit. In addition, EPA made other modifications to the proposed design and performance specification in response to public

comment as discussed above. As part of this process, EPA performed laboratory tests to ensure that the modifications achieved the intended objective.

While the results of these field tests and laboratory tests were largely confirmatory in nature and did not indicate a need to alter the basic design and performance specifications, they did identify areas that needed further refinement. Given that these tests were performed, by necessity, during and after the close of the public comment period and because the results were not available for placement in the docket until late in the rulemaking process, EPA is announcing, in a separate **Federal Register** notice being signed today, a supplemental comment period for the limited purpose of taking comments on these field and laboratory test results.

VII. Effective Date of the Revised PM Standards and Applicability of the Current PM_{10} Standards

In summary, the primary and secondary NAAQS for PM have been revised by establishing annual and 24-hour $PM_{2.5}$ standards; and by changing the form of the existing 24-hour PM_{10} standards. The existing PM_{10} annual standards have been retained. Section 50.3 (reference conditions) of 40 CFR part 50 has been revised to remove the adjustment of measured PM_{10} concentrations to standard conditions of temperature and pressure with respect to the revised PM standards. (Although EPA is retaining the current annual PM_{10} standards, the revision of 40 CFR 50.3 potentially may affect the effective stringency of the annual standards.) A new Appendix M has been added to 40 CFR part 50 that reflects the revision of 40 CFR 50.3. A new Appendix N to 40 CFR part 50 has been added to reflect the forms of the $PM_{2.5}$ and revised PM_{10} standards. Finally, a new Appendix L to 40 CFR part 50 has been added that specifies the reference method for measuring $PM_{2.5}$ in the ambient air.

The revised PM NAAQS, the revisions to 40 CFR 50.3, and the new Appendices M, N, and L to 40 CFR part 50 will become effective September 16, 1997. Inherent in the establishment of this revised set of PM standards and related provisions is the revocation of the current set of PM_{10} standards and associated provisions. To provide for an effective transition from the existing PM standards to the revised PM standards —in light of the need to establish $PM_{2.5}$ monitoring networks, designate areas, and develop control strategies for $PM_{2.5}$—the Administrator has determined that the effective date of the revocation of the current set of PM_{10} standards and associated provisions should be delayed so that the existing standards and associated provisions will continue to apply for an interim period. The duration of the interim period would depend on whether the area in question has attained the current PM_{10} standards, as described below in this unit.

First, section 172(e) of the Act provides that, if the Administrator relaxes a national primary ambient air quality standard, she shall, within 12 months after the relaxation, promulgate requirements applicable to all areas that have not attained that standard as of the date of the relaxation. Those requirements shall provide for controls that are not less stringent than the controls applicable to areas designated nonattainment before such relaxation. Although the set of revised PM standards, viewed as a whole, is more stringent than the set of current PM standards, it appears that the shift from the current PM_{10} standards to the revised PM_{10} standards, viewed in and of itself, represents a relaxation of the current PM_{10} standards. As a result, section 172(e) of the Act requires EPA to issue a rule within 12 months to apply implementation requirements no less stringent than the currently applicable requirements for those areas that have not yet attained the current PM_{10} standard(s) by today's promulgation. However, the Act does not specifically provide how to ensure that States with current PM_{10} problems should maintain the necessary public health protection in the interim between promulgation of a relaxed standard and issuance of a rule under section l72(e) of the Act. For that reason, EPA believes that it is both necessary and appropriate to defer the effective date of the revocation of the current PM_{10} standards, for areas that have not attained those standards, until EPA issues the rule called for by section 172(e) of the Act.

Second, since it will take many years for States to identify PM problems under the revised standards and to develop effective means for addressing those problems, EPA believes it is necessary for even those areas that have already attained the current PM_{10} standards (and hence are not subject to the terms of section 172(e) of the Act) to continue their current PM_{10} implementation efforts for the purpose of protecting public health in the transition to implementation of the revised standards.

In order to deal with both of these categories of areas—those that are not attaining the current PM_{10} standards and those that are in attainment of the current PM_{10} standards—EPA is taking a two-pronged approach towards deferral of the effective date of the revocation of the current PM_{10} standards. For those areas that are not attaining the current PM_{10} standards at the time of the promulgation of the revised PM_{10} standards, the current standards will continue to apply until EPA has completed its rulemaking under section 172(e) of the Act to prevent backsliding in those areas. This will assure that no backsliding can occur in the interim period between the promulgation of the revised standards and the completion of the rulemaking under section 172(e) of the Act. For those areas that are attaining the current PM_{10} standards at the time of promulgation of the revised PM_{10} standards, the existing PM_{10} standards will continue to apply until the areas have an approved SIP that includes any control measures that had been adopted and implemented at the State level to meet the current PM_{10} NAAQS and have an approved section 110 SIP for purposes of implementing the revised PM standards. If an area has already received approval of a PM_{10} SIP embodying all of the measures that had been adopted and implemented at the State level, no further Part D submission or approval would be necessary. If an area has already submitted such measures, EPA would need to take action to approve them. Finally, if an area has not yet submitted such measures to EPA for inclusion in the SIP, the area would need to submit them and EPA would need to approve them. This submission and approval would serve to satisfy both the area's remaining subpart D obligations and, in part, its new obligations under section 110(a)(1) of the Act regarding the implementation of the revised PM NAAQS. EPA emphasizes that it is not requiring an approval of a modeled attainment demonstration for the current PM_{10} NAAQS, only an approval of the control measures that had in fact been adopted and implemented and that, therefore, were responsible for the area's attainment of the current PM_{10} standards.

The existing definition of reference conditions and 40 CFR part 50, Appendices J and K will remain in force as long as the current PM_{10} standards apply to an area. Additional policies and guidance for assuring an effective transition will be set forth in future EPA guidance, policies, and/or rules.

VIII. Regulatory and Environmental Impact Analyses

As discussed in Unit IV of this preamble, the Clean Air Act and judicial

decisions make clear that the economic and technological feasibility of attaining ambient standards are not to be considered in setting NAAQS, although such factors may be considered in the development of State plans to implement the standards. Accordingly, although, as described below, a Regulatory Impact Analysis (RIA) has been prepared, neither the RIA nor the associated contractor reports have been considered in issuing this final rule.

A. Executive Order 12866

Under Executive Order 12866, 58 FR 51735 (October 4, 1993), the Agency must determine whether a regulatory action is ''significant'' and, therefore, subject to Office of Management and Budget (OMB) review and other requirements of the Executive Order. The order defines ''significant regulatory action'' as any regulatory action that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another Agency.

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof.

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

In view of its important policy implications, this action has been judged to be a ''significant regulatory action'' within the meaning of the Executive Order. As a result, under section 6 of the Executive Order, EPA has prepared an RIA, entitled ''Regulatory Impact Analysis for Particulate Matter and Ozone National Ambient Air Quality Standards and Proposed Regional Haze Rule (July 1997).'' This RIA assesses the costs, economic impacts, and benefits associated with potential State implementation strategies for attaining the PM and O_3 NAAQS and the proposed Regional Haze Rule. Changes made in response to OMB suggestions or recommendations will be documented in the public docket and made available for public inspection at EPA's Air and Radiation Docket Information Center (Docket No. A-95-58). The RIA will be publicly available in hard copy by contacting the U.S. Environmental Protection Agency Library at the address under ''Availability of Related Information'' and in electronic form as discussed above in ''Electronic Availability.''

B. Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601 *et seq.*, provides that, whenever an agency is required to publish a general notice of rulemaking for a proposal, the agency must prepare an initial regulatory flexibility analysis for the proposal unless the head of the agency certifies that the rule will not, if promulgated, have a significant economic impact on a substantial number of small entities (section 605(b)). The EPA certified the proposed NAAQS rule based on its conclusion that the rule would not establish requirements applicable to small entities and therefore would not have a significant economic impact on small entities within the meaning of the RFA. See 61 FR 65638, 65668 (PM proposal) and 61 FR 65716, 65764 (ozone proposal), both published December 13, 1996. Accordingly, the Agency did not prepare an initial regulatory flexibility analysis for the proposal, but it did conduct a more general analysis of the potential impact on small entities of possible State strategies for implementing any new or revised NAAQS.

At the heart of EPA's certification of the proposed NAAQS rule was the Agency's interpretation of the word ''impact'' as used in the RFA. Is the ''impact'' to be analyzed under the RFA a rule's impact on the small entities that will be subject to the rule's requirements, or the rule's impact on small entities in general, whether or not they will be subject to the rule? In the case of NAAQS rules, the question arises because of the congressionally designed mixture of Federal and State responsibilities in setting and implementing the NAAQS.

As EPA explained in the proposal, NAAQS rules establish air quality standards that States are primarily responsible for meeting. Under section 110 and Part D of Title I of the Act, every State develops a State Implementation Plan (SIP) containing the control measures that will achieve a newly promulgated NAAQS. States have broad discretion in the choice of control measures. As the U.S. Supreme Court noted in *Train* v. *NRDC*, 421 U.S. 60 (1975), 95 S. Ct. 1470:

> [P]rimary [NAAQS] deal with the quality of outdoor air and are fixed on a nationwide basis at a level which the agency determines will protect the public health. It is the attainment and maintenance of these standards which section 110(a)(2)(A) requires that State plans provide. In complying with this requirement, a State's plan must include ''emission limitations'' which are regulations of the composition of substances emitted into the ambient air from such sources as power plants, service stations and the like. They are the specific rules to which operators of pollution sources are subject and which, if enforced, should result in ambient air which meets the national standards.
>
> The Agency is plainly charged by the Act with the responsibility for setting the national ambient air standards. Just as plainly, it is relegated to a secondary role in the process of determining and enforcing the specific, source-by-source emission limitations which are necessary if the national standards are to be met. Under 110(a)(2), the Agency *is required* to approve a State plan which provides for the timely attainment and maintenance of the ambient air standards, and which also satisfies that sections other general requirements. The Act gives the agency no authority to question the wisdom of a state's choices of emission limitations if they are part of a plan which satisfies the standards of 110(a)(2) and the Agency may devise and promulgate a plan of its own only if the State fails to submit an implementation plan which satisfies those standards. Section 110(c).
>
> 421 U.S. 60 at 78–79 (emphasis in original). In short, NAAQS rules themselves do not establish any control requirements applicable to small entities. State rules implementing the NAAQS may establish such requirements and the extent to which they do depends primarily on each State's strategy for meeting the NAAQS.[95]

To determine the proper interpretation of impact under the RFA, EPA considered the RFA's stated purpose, its requirements for regulatory flexibility analyses, its legislative history, the amendments made by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA) (Pub. L. 104–121), and caselaw. The EPA concluded that all of these traditional tools of statutory construction point in one direction—that an agency is required to assess the impact of a rule on the small entities that will be subject to the rule's requirements, because the purpose of a regulatory flexibility analysis is to consider ways of easing or even waiving a rule's requirements as they will apply to small entities, consistent with the statute authorizing

[95] It is worth noting that Federal rules that apply nationally also play a role in reducing emissions governed by NAAQS. For instance, EPA rules under Title II of the Act require reductions in ozone-forming emissions from on and off-road vehicles and the fuels that power them. When EPA issues such rules, it conducts the analysis required under the RFA. For example, EPA performed regulatory flexibility analyses for the reformulated gasoline rule issued under section 211(k) of the Act. See 59 FR 7716, February 16, 1994.

the rule. That purpose cannot be served in the case of the rules like the NAAQS that do not have requirements that apply to small entities.

More specifically, EPA noted that its interpretation of ''impact'' flows from the express purpose of the RFA itself. As the RFA's ''Findings and Purposes'' section (Pub. L. 96–354, section 2) makes clear, Congress enacted the RFA in 1980 out of concern that agencies were writing one-size-fits-all regulations that in fact did not fit the size and resources of small entities. Congress noted that it is generally easier for big businesses to comply with regulations, and that small businesses are therefore at a competitive disadvantage in complying with uniform rules. Congress also noted that small entities' relative contribution to the problem a rule is supposed to solve may not warrant applying the same requirements to large and small entities alike. In the RFA itself, Congress therefore stated:

> It is the purpose of this Act to establish as a principle of regulatory issuance that agencies shall endeavor, consistent with the objectives of the rule and of applicable statutes, to fit regulatory and informational requirements to the scale of the businesses, organizations, and governmental jurisdictions subject to regulation.

(Pub. L. 96–354, section 2(b))

The EPA further noted that the RFA sections governing initial and final regulatory flexibility analyses reflect this statement of purpose. Sections 603 and 604 of the RFA require that initial and final regulatory flexibility analyses identify the types and estimate the numbers of small entities ''to which the proposed will apply'' (sections 603(b)(3) and 604(a)(3) of the RFA). Similarly, they require a description of the ''projected reporting, recordkeeping, and other compliance requirements of the proposal, including an estimate of the classes of small entities which will be subject to the requirement'' (sections 603(b)(4) and 604(a)(4)). At the core of the analyses is the requirement that agencies identify and consider ''significant regulatory alternatives'' that would ''accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposal on small entities'' (sections 603(c) and 604(a)(5)). Among the types of alternatives agencies are to consider are the establishment of different ''compliance or reporting requirements or timetables'' for small entities and the exemption of small entities ''from coverage of the rule, or any part'' of the rule (section 603(c)(1) and (4) of the RFA). The RFA thus makes clear that regulatory flexibility analyses are to focus on how to minimize rule requirements on small entities.

As EPA further explained, since regulatory flexibility analyses are not required for a rule that will not have a ''significant economic impact on a substantial number of small entities'', it makes sense to interpret ''impact'' in light of the requirements for such analyses. Regulatory flexibility analyses, as described in this unit, are to consider how a rule will apply to small entities and how its requirements may be minimized with respect to small entities. In this context, ''impact'' is appropriately interpreted to mean the impact of a rule on the small entities subject to the rule's requirements.

The Agency cited two Federal court cases in support of its interpretation. In *Mid-Tex Elec. Co-op* v. *FERC*, 773 F.2d 327, 342 (D.C. Cir. 1985), petitioners claimed that the RFA required an agency to analyze the effects of a rule on small entities that were not regulated by the rule but might be indirectly impacted by it. Petitioners noted that the Small Business Administration (SBA) also interpreted the RFA to require analysis of a rule's impact on small entities not regulated by the rule, and argued that the court should defer to the SBA's position in light of its compliance monitoring role under the RFA. After reviewing the RFA's ''Findings and Purposes'' section, its legislative history, and its requirements for regulatory flexibility analyses, the Mid-Tex court rejected petitioners' interpretation. As the court explained:

> The problem Congress stated it discerned was the high cost to small entities of compliance with uniform regulations, and the remedy Congress fashioned—careful consideration of those costs in regulatory flexibility analyses—is accordingly limited to small entities subject to the proposed regulation * * *. [W]e conclude that an agency may properly certify that no regulatory flexibility analysis is necessary when it determines that the rule will not have a significant economic impact on a substantial number of small entities that are subject to the requirements of the rule.

Id. at 342. Notably, Congress let this interpretation stand when it recently amended the RFA in enacting SBREFA.

The EPA also cited a recent case affirming the Mid-Tex court's interpretation. In *United Distribution Companies* v. *FERC*, 88 F.3d 1105, 1170 (D.C. Cir. 1996), the court noted that the Mid-Tex court:

> * * * conducted an extensive analysis of RFA provisions governing when a regulatory flexibility analysis is required and concluded that no analysis is necessary when an agency determines ''that the rule will not have a significant economic impact on a substantial number of small entities *that are subject to the requirements of the rule*''.

Id., citing and quoting Mid-Tex (emphasis added by United Distribution court). The Agency went on to explain that given the Federal/State partnership for attaining healthy air, the proposed NAAQS, if adopted, would not establish any requirements applicable to small entities. Instead, any new or revised standard would establish levels of air quality that States would be primarily responsible for achieving by adopting plans containing specific control measures for that purpose. The proposed NAAQS rule was thus not susceptible to regulatory flexibility analysis as prescribed by the amended RFA. Since it would establish no requirements applicable to small entities, it afforded no opportunity for EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables, or exemptions from all or part of the rule. For these reasons, EPA certified that the proposal ''will not, if promulgated, have a significant economic impact on a substantial number of small entities,'' within the meaning of the RFA. Because EPA was not required to prepare an initial regulatory flexibility analysis for the rule, it was also not required to convene a Small Business Advocacy Review Panel for the rule under section 609(b) of the RFA, as added by SBREFA.

Notwithstanding its certification of the proposal, EPA recognized that the proposed NAAQS, if adopted, would begin a process of State implementation that could eventually lead to small entities having to comply with new or different control measures, depending on the implementation plans developed by the States. EPA also recognized that the Act does not allow EPA to dictate or second-guess how States should exercise their discretion in regulating to attain any new or revised NAAQS. Under those circumstances, EPA concluded that the best way to take account of small entity concerns regarding any new or revised NAAQS was to work with small entity representatives and States to provide information and guidance on how States could address small entity concerns when they write their implementation plans.

In line with this approach, as part of RIA it prepared for the proposed NAAQS, EPA analyzed how hypothetical State plans for implementing the proposal might affect small entities. The analysis was necessarily speculative and limited, since it depended on projections about what States might do several years in the future and did not take into account

any new strategies that might be developed and recommended by the FACA subcommittee formed to help devise potential strategies for implementing a new or revised NAAQS (see discussion of RIA and FACA process in this document). Nevertheless, the analysis provided as much information on potential small entity impacts as was reasonably available at the time of the proposal.

The Agency also took steps to ensure that small entities' voices were heard in the NAAQS rulemaking itself. With Jere Glover, Chief Counsel for Advocacy of the SBA, EPA convened outreach meetings modeled on the SBREFA panel process to solicit and convey small entities' concerns with the proposed NAAQS. Two meetings were held as part of that process, on January 7 and February 28, 1997, with a total attendance of 41 representatives of small businesses, small governments, and small nonprofit organizations. Both meetings were attended by representatives of SBA and OMB, as well as of EPA. The key concerns raised by small entities at those meetings related to the scientific foundation of the proposed NAAQS and the potential cost of implementing it, the same concerns raised by other industry commenters on the proposal. The Agency produced a report on the meetings to ensure that small entity concerns were part of the rulemaking record when EPA made its final decision on the proposal.

In light of States' pivotal role in NAAQS implementation, EPA also undertook a number of additional activities to assist and encourage the States to be sensitive to small entity impacts as they implement any new or revised NAAQS. With the SBA, EPA began an interagency panel process to collect advice and recommendations from small entity representatives on how States could lessen any impacts on small entities. The EPA plans to issue materials in two phases to help States develop their implementation plans. In view of States' discretion in implementing the NAAQS, these materials will mostly take the form of guidance, which is not subject to the RFA's requirement for initial regulatory flexibility analysis. (Under section 603 of the RFA, that requirement applies only to binding rules that are required to undergo notice and comment rulemaking procedures.) But regardless of the form such materials take, EPA is employing panel procedures to ensure that small entities have an opportunity to raise any concerns prior to the materials being issued in draft form.

To supplement the input the Agency receives from the ongoing FACA process (described previously in this document), EPA also added more small entity representatives to the Subcommittee on implementation of any new or revised NAAQS. These representatives have formed a small entity caucus to develop and bring to the Subcommittee a focused approach to small entity issues. These new Subcommittee members are also part of the group in the aforementioned panel process. By means of these various processes, EPA hopes to promote the consideration of small entity concerns and advice throughout the NAAQS implementation process.

In response to the proposal, a number of commenters questioned EPA's decision to certify that the proposed NAAQS will not have a significant impact on a substantial number of small entities. Some commenters disagreed with EPA's view that the proposed NAAQS would not establish regulatory requirements applicable to small entities. These commenters argued that a number of control requirements applicable to small entities would automatically result from promulgation of the proposed NAAQS, such as new reasonable further progress, SIP and Federal Implementation Plan (FIP) requirements. Other commenters stated that it is possible for EPA to assess the impacts of the NAAQS revision on small entities and that, to a limited extent, EPA has already done so. Further, a number of commenters argued that EPA has a legal obligation under the RFA, as amended by SBREFA, to choose a NAAQS alternative that minimizes the impact on small entities. Some commenters questioned EPA's interpretations of the Mid-Tex and United Distribution cases. In addition, other commenters stated that EPA's position regarding the NAAQS and the RFA is inconsistent with its past practice and the legislative history of the RFA. Finally, a few commenters noted that the panel process EPA conducted for the proposed NAAQS did not satisfy the requirements of SBREFA.

EPA disagrees that promulgation of the NAAQS will automatically result in control requirements applicable to small entities that EPA can and must analyze under the RFA. As noted previously in this unit, a NAAQS rule only establishes a standard of air quality that other provisions of the Act call on States (or in case of State inaction, the Federal government) to achieve by adopting implementation plans containing specific control measures for that purpose. Following promulgation of a new or revised NAAQS, section 110 of the Act requires States and EPA to engage in a designation process to determine what areas within each State's borders are attaining or not attaining the NAAQS. Under section 110 and Parts C and D of Title I of the Act, States then conduct a planning process to develop and adopt their SIPS. Depending on an area's designation for the particular NAAQS, these and other Title I provisions of the Act require a State's SIP to contain certain control programs in addition to the control measures that the State decides are also needed to attain and maintain the NAAQS.

The fact that the Act requires SIPs to contain certain control programs under certain circumstances does not mean that EPA either can or must conduct a regulatory flexibility analysis of a rule establishing a NAAQS. Just from the standpoint of feasibility, EPA cannot know which areas will be subject to what mandatory SIP programs until after the designation process is completed. Beyond that, any mandatory SIP programs are still implemented by the States, and States have considerable discretion in how they implement them. For instance, the reasonable further progress requirement under section 172 of the Act leaves States broad discretion to determine the rate of progress and the control measures to achieve that progress.[96] As a result, EPA cannot be certain where and how any mandatory programs will be implemented with respect to small (or large) entities. Much less can EPA know about how States will exercise their discretion to develop additional controls needed to attain and maintain the NAAQS.

Even if EPA could know exactly how any mandatory SIP programs would apply to small entities, the purpose of the RFA is not served by attempting a regulatory flexibility analysis of State implementation of those programs. As explained previously in this unit, the RFA and the caselaw interpreting it clearly establish that the purpose of the RFA is to promote Federal agency efforts to tailor a rule's requirements to the scale of the small entities that will be subject to it. That purpose cannot be served in the case of a NAAQS rule since the rule does not establish requirements applicable to small

[96]The SIP requirements of subpart 4 of Part D of Title I of the Act apply to SIPs for areas designated as not attaining NAAQS for PM_{10}. Those requirements will not apply to SIPs to implement the $PM_{2.5}$ NAAQS. Further, to the extent SIPs for areas in nonattainment with the applicable PM_{10} NAAQS remain subject to subpart 4 requirements, there will be no incremental change in the impact on sources regulated by the States' SIPs pursuant to those requirements as a result of this promulgation.

entities. In promulgating a NAAQS, the only choice before EPA concerns the level of the standard, not its implementation. While mandatory SIP programs may ultimately follow from promulgation of the NAAQS, there is nothing EPA can do in setting the NAAQS to tailor those programs as they apply to small entities. Whether and how the programs will apply in particular nonattainment areas is beyond the scope of the NAAQS rulemaking and, indeed, beyond EPA's reach in any rulemaking to the extent the applicability and terms of the programs are prescribed by statute.[97] Moreover, any mandatory SIP programs are supplemented by discretionary State controls that EPA has no power to tailor under the RFA or the Act (see *Train* v. *NRDC*, quoted previously in this unit).

The commenters' suggestions for minimizing the potential impact of the NAAQS rule on small entities run afoul of both the RFA and the Act. Some suggested that EPA set a less stringent standard (or no standard at all in the case of $PM_{2.5}$) to reduce the chance that small entities would become subject to new or tighter SIP requirements. Others suggested that EPA require States to exempt small entities from new or tighter SIP requirements. However, as explained previously in this document, the RFA neither requires nor authorizes EPA to set a less stringent NAAQS than the applicable Clean Air Act provisions allow in order to reduce potential small entity impacts. Indeed, the RFA provides that any means of providing regulatory flexibility to small entities be consistent with the statute authorizing the rule. Moreover, even if EPA set a less stringent standard, States could still exercise their discretion to obtain any needed emission reductions from small entities. As the Supreme Court in *Train* v. *NRDC* made clear, EPA has no authority to forbid States from obtaining reductions from any particular category of stationary sources, including small entities. See also, *Virginia* v. *EPA*, No. 108 F.3d 1397, 1408 (D.C. Cir. 1997), quoting *Union Electric* v. *EPA*, 427 U.S. 246, 269 (1976) (''section 110 left to the states the power to determine which sources would be burdened by regulations and to what extent'').

EPA's approval of SIPs for the new or revised NAAQS also will not establish new requirements, but will instead simply approve requirements that a State is already imposing. And again, EPA does not have authority to disapprove a State's plan except to the extent that the plan fails to demonstrate attainment and maintenance of the NAAQS as required by Title I of the Clean Air Act. In cases where EPA promulgates a FIP, EPA might establish control requirements applicable to small entities, and in such a circumstance, EPA would conduct the analyses required by the RFA.

Some commenters argued that under the RFA as amended by SBREFA, EPA now has an obligation to choose the alternative that minimizes the impact on small entities when setting the NAAQS. As indicated previously in this unit, EPA disagrees with the commenters' argument for the reasons stated in this document's discussion of the Agency's authority to consider costs and other factors not related to public health in setting and revising primary NAAQS. In a nutshell, both the text and legislative history of the RFA make clear that the RFA does not override the substantive provisions of the statute authorizing the rule, but only requires agencies to identify and consider ways of minimizing the economic impact on small entities subject to the rule in a manner consistent with the authorizing statute.

Some commenters disagreed with EPA's interpretation of the Mid-Tex and United Distribution cases. In particular, these commenters noted that in those cases the relevant regulatory agency, Federal Energy Regulatory Commission (FERC), wholly lacked jurisdiction to regulate the small entities at issue. According to these commenters, EPA does have the ability and jurisdiction to regulate small entities in the case of the NAAQS, and therefore EPA's reliance on Mid-Tex and United Distribution is misplaced.

The commenters' attempt to distinguish the FERC cases from the NAAQS rulemaking wholly overlooks the courts' reasoning, which in fact fully supports EPA's certification of the proposed NAAQS. As described previously in this unit, the Mid-Tex court exhaustively reviewed the relevant sections of the RFA and its legislative history. Its analysis revealed that Congress passed the RFA out of concern with one-size-fits-all regulations and fashioned a remedy limited to regulations that apply to small entities. This principle is fully applicable to the NAAQS, which creates no rule requirements that apply to small entities.

The fact that FERC had no regulatory authority over the small entities indirectly affected by its rules played no essential role in the court's rationale. FERC could (and apparently did in the Mid-Tex rulemaking) estimate the potential indirect impact of its rules on small entities. Presumably, FERC could have also mitigated any indirect impact by changing some aspect of the rule (or else the small entities would have had no incentive to sue the agency). The court nevertheless found it unnecessary for FERC to do either, based on its reading of the RFA as limited to analysis of a rule's impact on the small entities subject to the rule's requirements. In reaching its decision, the court noted that requiring agencies to ''consider every indirect effect that any regulation might have on small businesses * * * is a very broad and ambitious agenda, * * * that Congress is unlikely to have embarked on * * * without airing the matter.'' Mid-Tex, 773 F.d. at 343.

The commenters also overstate EPA's regulatory authority over small entities with respect to the regulation of criteria pollutants. Various provisions of the Clean Air Act authorize EPA to regulate various types of sources at the Federal level to accomplish specified goals. However, EPA's authority to more generally regulate sources, including small entities, in the manner of SIPs is limited to instances of State default of SIP responsibilities. When that occurs, EPA may issue a FIP containing specific control measures, and to the extent a proposed FIP would establish control measures applicable to small entities, EPA would analyze the small entity impact of those measures as required by the RFA. In 1994, for example, EPA prepared an initial regulatory flexibility analysis when it proposed a FIP for Los Angeles. See 59 FR 23264 (May 5, 1994).

As noted previously in this unit, Congress let the Mid-Tex interpretation stand when it recently amended the RFA in enacting SBREFA. If it had disagreed with the court's decision, it would have revised the relevant statutory provisions or otherwise indicated its disagreement when it enacted SBREFA. Instead, Congress actually reinforced the Mid-Tex court's interpretation of the RFA in enacting section 212(a) of SBREFA. That section requires that an agency issue a ''small entity compliance guide'' for ''each rule * * * for which an agency is required to prepare a final regulatory flexibility analysis under section 604'' of the RFA. The guide is ''to assist small entities in complying with the rule'' by ''explain[ing] the actions a small entity is required to take to comply'' with the rule (section 212(a) of SBREFA). Obviously, it makes no sense to prepare a small entity compliance guide for a rule that does not apply to small entities. Thus SBREFA stands as further confirmation that Congress intended the

[97] If and when the Agency issues any rules addressing State implementation of any statutorily required actions, EPA would analyze and address the impact of those rules on small entities as appropriate under the RFA.

RFA to address only rules that establish requirements small entities must meet. Since SBREFA's passage, the United Distribution court has affirmed the Mid-Tex court's interpretation.

Some commenters noted that EPA's informal panel process did not comply with the requirements of SBREFA. The EPA did not convene a SBREFA panel because such a panel is not required for rules like the NAAQS that do not apply to small entities. Under the RFA as amended by SBREFA, since the Agency certified the proposal, it was not required to convene a panel for it. Nevertheless, EPA conducted the voluntary panel process described previously in this unit, as well as other voluntary small business outreach efforts. The process could not comply with the analytical requirements of the RFA for the reasons given in this unit. However, it could and did ensure that EPA heard directly from small entities about the NAAQS proposals.

A few commenters stated that EPA's view of the NAAQS and the RFA is inconsistent with EPA's past positions regarding the RFA and NAAQS revisions. Some commenters also cited the RIA for the proposed NAAQS and noted that this analysis demonstrates EPA's ability to estimate the impact of the NAAQS on small entities, thereby undercutting EPA's argument that it is not able to perform a regulatory flexibility analysis when setting the NAAQS.

Past **Federal Register** documents make clear that the nature of the NAAQS makes a regulatory flexibility analysis inapplicable to NAAQS rulemakings. For instance, in 1984, EPA stated that a ''NAAQS for NO_x by itself has no direct impact on small entities. However, it forces each State to design and implement control strategies for areas not in attainment.'' See 49 FR 6866, 6876 (February 23, 1984); see also, 50 FR 37484, 37499 (September 13, 1985); 50 FR 25532, 25542 (June 19, 1985) (NAAQS for NO_2 do not impact small entities directly). EPA stated again in 1987 that the NAAQS ''themselves do not contain emission limits or other pollution controls. Rather, such controls are contained in state implementation plans.'' See 52 FR 24634, 24654 (July 1, 1987).

EPA has typically performed an analysis to assess, to the extent practicable, the potential impact of retaining or revising the NAAQS on small entities, depending on possible State strategies for implementing the NAAQS. These analyses have provided as much insight into the potential small entity impacts of implementing revised NAAQS as could be provided at the NAAQS rulemaking stage. In some instances, these preliminary analyses were described as ''regulatory flexibility analys[es]'' or as analyses ''pursuant to this [Regulatory Flexibility] Act.'' See, e.g., 52 FR 24634, 24654 (July 1, 1987); 50 FR 37484, 37499 (September 13, 1985).

However, these analyses were based on hypothetical State control strategies, and EPA made the point on various occasions that any conclusions to be drawn from such analyses were speculative, given that the NAAQS themselves do not impose requirements on small entities. Although these past analyses reflected the Agency's best efforts to evaluate potential impacts, they were not regulatory flexibility analyses containing the necessary elements required by the RFA. These analyses, for example, did not describe the reporting, recordkeeping, and other compliance requirements of the proposed NAAQS rules that would apply to small entities, since the NAAQS rules did not apply to small entities. Nor did they determine how the proposed NAAQS rules could be eased or waived for small entities. Such an analysis is not possible in the case of the NAAQS. To the extent EPA labeled these analyses regulatory flexibility analyses in the past, that label was inappropriate. EPA's current practice is to describe such an analysis more accurately as a general analysis of the potential cost impacts on small entities. See, e.g., 61 FR 65638, 65669, 65747 (December 13, 1996) (current O_3 and PM NAAQS proposals).[98] EPA's analytical approach to small entity impacts of the NAAQS has thus remained consistent over time.

One commenter noted that the legislative history of the RFA suggests that the RFA was intended to apply to the NAAQS. As noted previously in this unit, EPA's reading of both the RFA and SBREFA, based on the language of the statute as amended and its legislative histories and applicable caselaw, is that the RFA requirements at issue do not apply to the NAAQS. The legislative history cited by the commenter does not change this conclusion.

In fact, the statement by Senator Culver on which the commenter relies does not indicate that the NAAQS should be subject to regulatory flexibility analyses. Rather, Senator Culver uses the NAAQS as an example of the type of standard that agencies would not change as a result of the RFA. According to Senator Culver, section 606 of the RFA ''succinctly states that this bill does not alter the substantive standard contained in underlying statutes which defines the agency's mandate.'' 126 Cong. Rec. S 21455 (August 6, 1980) daily ed. After citing section 109 of the Act, Senator Culver goes on to describe EPA's bubble policy (which addresses the limits on emissions from a particular facility) as the type of flexible regulation that agencies should consider, once EPA has set a NAAQS. ''The important point for purposes of this discussion is that the 'bubble concept,' a type of flexible regulation, in no manner altered the basic statutory substantive standard of the EPA * * *. No regulatory flexibility analysis alters the substantive standard otherwise applicable by law to agency action.'' *Id.* Thus, contrary to the suggestion of the commenter, Senator Culver's statement actually confirms that the time to consider regulatory flexibility is when regulations applicable to sources are being established, not when a NAAQS itself is being set.

Under section 604 of the RFA, whenever an agency promulgates a final rule under section 553 of the Administrative Procedure Act, after being required by that section or any other law to publish a general notice of proposed rulemaking (NPRM), the agency is required to prepare a final regulatory flexibility analysis. RFA section 605(b) provides, however, that section 603 (re initial regulatory flexibility analyses) and section 604 do not apply if the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities and publishes such certification at the time of publication of the NPRM or at the time of the final rule.

As noted above, EPA certified this final rule at the time of the NPRM. After considering the public comments on the certification, EPA continues to believe that this final rule will not have a significant economic impact on a substantial number of small entities for the reasons explained above and that it

[98] As commenters pointed out, the RIA for the proposed PM NAAQS does state that ''[t]he screening analysis * * * provides enough information for an initial regulatory flexibility analysis (RFA) if such an analysis were to be done.'' That statement was mistaken and was not made in the RIA for the proposed ozone NAAQS. While both RIAs attempted to gauge the potential impact on small entities of State implementation of the proposed NAAQS, neither could or did identify any specific control or information requirements contained in the NAAQS rule that would apply to small entities. Indeed, both RIAs made clear that the impact being analyzed was that of potential State measures to attain the NAAQS, and that such an analysis was inherently speculative and uncertain. Thus, the RIAs actually confirm EPA's statement in the preambles for the proposed NAAQS that conducting a complete regulatory flexibility analysis is not feasible for rules setting or revising a NAAQS.

therefore appropriately certified the rule. Further, as required by the Clean Air Act, EPA is promulgating this final rule under section 307(d) of the Clean Air Act. For all the foregoing reasons, EPA has not prepared a final regulatory flexibility analysis for the rule. The Agency has nonetheless analyzed in the final RIA for the rule the potential impact on small entities of hypothetical State plans for implementing the NAAQS. The Agency also plans to issue guidance to the States on reducing the potential impact on small entities of implementing the NAAQS.

C. Impact on Reporting Requirements

There are no reporting requirements directly associated with the finalization of ambient air quality standards under section 109 of the Act (42 U.S.C. 7400). There are, however, reporting requirements associated with related sections of the Act, particularly sections 107, 110, 160, and 317 (42 U.S.C. 7407, 7410, 7460, and 7617).

In EPA's final revisions to the air quality surveillance requirements (40 CFR part 58) for PM, the associated RIA addresses the Paperwork Reduction Act requirements through an Information Collection Request.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of certain regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. This requirement does not apply if EPA is prohibited by law from considering section 202 of UMRA estimates and analyses in adopting the rule in question. Before promulgating a final rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. These requirements do not apply when they are inconsistent with applicable law. Moreover, section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation of why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements. Section 204 of UMRA requires each agency to develop ''an effective process to permit elected officers of state, local and tribal governments * * * to provide meaningful and timely input'' in the development of regulatory proposals containing a significant Federal intergovernmental mandate.[99]

The EPA has determined that the provisions of sections 202 and 205 of UMRA do not apply to this decision.''Unless otherwise prohibited by law,'' EPA is to prepare a written statement under section 202 of UMRA that is to contain assessments and estimates of the costs and benefits of a rule containing a Federal mandate. Congress clarified that ''unless otherwise prohibited by law'' referred to whether an agency was prohibited from considering the information in the rulemaking process, not to whether an agency was prohibited from collecting the information. The Conference Report on UMRA states, ''This section [202] does not require the preparation of any estimate or analysis if the agency is prohibited by law from considering the estimate or analysis in adopting the rule.'' 141 Cong. Rec. H3063 (daily ed. March 13, 1995). Because the Clean Air Act prohibits EPA, when setting the NAAQS, from considering the types of estimates and assessments described in section 202 of UMRA, UMRA does not require EPA to prepare a written statement under section 202.[100] The requirements in section 205 of UMRA do not apply because those requirements only apply to rules ''for which a written statement is required under section 202 * * *.''

The EPA has determined that the provisions of section 203 of UMRA do not apply to this decision. Section 203 of UMRA only requires the development of a small government agency plan for requirements with which small governments might have to comply. Since setting the NAAQS does not establish requirements with which small governments might have to comply, section 203 of UMRA does not apply. The EPA acknowledges, however, that any corresponding revisions to associated SIP requirements and air quality surveillance requirements, 40 CFR parts 51 and 58, respectively, might result in such effects.Accordingly, EPA did address unfunded mandates when it proposed revisions to 40 CFR part 58, and will do so, as appropriate, when it proposes any revision to 40 CFR part 51.

With regard to the outreach described in section 204 of UMRA, EPA did follow a process for providing elected officials with an opportunity for meaningful and timely input into the proposed NAAQS revisions, although EPA did not describe this process in the proposal. The EPA conducted a series of pre-proposal outreach meetings with State and local officials and their representatives that permitted these officials to provide meaningful and timely input on issues related to the NAAQS and the monitoring issues associated with them. Beginning in January, 1996, EPA briefed State and local air pollution control officials at national meetings with State and Territorial Air Pollution Program Administrators (STAPPA) / Association of Local Air Pollution Control Officials (ALAPCO) in Washington, DC, North Carolina, Chicago, and Nevada. The EPA also held briefings for the Washington, DC representatives of several State and local organizations, including National Conference of State Legislators, U.S. Conference of Mayors,

[99] As noted in unit VIII.B., a NAAQS rule only establishes a standard of air quality that other provisions of the Act call on States (or in the case of State inaction, the Federal government) to achieve by adopting implementation plans containing specific control measures for the purpose. Thus, it is questionable whether the NAAQS itself imposes an enforceable duty and thus whether it is a significant Federal mandate within the meaning of UMRA. EPA need not and does not reach this issue in this document. For the reasons given in this unit, even if the NAAQS were determined to be a significant Federal mandate, EPA does not have any obligations under sections 202 and 205 of UMRA, and EPA has met any obligations it would have under section 204 of UMRA.

[100] In addition to the estimates and assessments described in section 202 of UMRA, written statements are also to include an identification of the Federal law under which the rule is promulgated (section 202(a)(1) of UMRA) and a description of outreach efforts under section 204 of UMRA (section 202(a)(5) of UMRA). Although these requirements do not apply here because a written statement is not required under section 202 of UMRA, this preamble identifies the Federal law under which this rule is being promulgated and a written statement describing EPA's outreach efforts with State, local, and tribal governments will be placed in the docket.

National Governors Association, National League of Cities, and STAPPA/ALAPCO. EPA also held separate briefings and discussions with State and local officials at meetings set up by the National Governors Association, the U.S. Conference of Mayors and the Council of State Governments. The EPA also conducted in-depth briefings at each EPA regional office and regional staff also had several meetings and discussions with their State counterparts about the standards. The efforts described in this paragraph of this preamble, which provided elected officials with opportunity for meaningful and timely input into the proposed NAAQS revisions, met any requirements imposed by section 204 of UMRA. The docket will contain a written statement describing these outreach efforts, including a summary of the comments and concerns presented by State, local, and tribal governments and a summary of EPA's evaluation of those comments and concerns.

Several commenters disagreed with EPA that sections 202, 203, and 205 of UMRA do not apply to this decision. These commenters argued that EPA is not prohibited from considering costs in setting NAAQS under the Clean Air Act and applicable judicial decisions. Some commenters also expressed the view that there is no conflict between UMRA and the Clean Air Act with regard to the NAAQS. These commenters argued that UMRA and the NAAQS can be harmonized by reading UMRA as an information gathering statute and that EPA should therefore perform the analyses required by UMRA, regardless of whether costs may be considered. Finally, at least one commenter argued that in past NAAQS reviews, EPA did not dispute its UMRA obligations.

As discussed more fully in Unit IV. of this preamble, EPA is prohibited from considering cost in setting the NAAQS. Given that fact (as noted in Unit IV. of this preamble), sections 202 and 205 of UMRA do not apply.[101] As the Conference Report clarifies, UMRA itself states that the section 202 estimates and analyses are not required in cases such as the NAAQS, where an agency is prohibited by law from considering section 202 estimates and analyses. Reading UMRA in the manner suggested by the commenters would effectively read this provision out of UMRA; UMRA contains an exception for rules like the NAAQS, it must be given effect.

With regard to EPA's position regarding UMRA in previous NAAQS review exercises, EPA simply made plain in those situations that because it did not plan on revising the NAAQS, it determined, without further review, that sections 202, 203, and 205 of UMRA did not apply. EPA thus stated that:

> Because the Administrator has decided not to revise the existing primary NAAQS for SO_2, this action will not impose any new expenditures on governments or on the private sector, or establish any new regulatory requirements affecting small governments. Accordingly, EPA has determined that the provisions of sections 202, 203 and 205 do not apply to this final decision.

61 FR 25566, 25577, May 22, 1996; see also 61 FR 52852, 52856, October 8, 1996 (Same statement for NO_2 NAAQS). As this statement makes clear, EPA only determined that sections 202, 203, and 205 of UMRA did not apply to the NAAQS when EPA fails to revise the standard. Having made that determination, EPA had no reason to catalog additional bases for finding UMRA inapplicable. Nothing in that statement was intended to preclude EPA, or precludes EPA, from concluding for other reasons (such as those discussed in this unit) that UMRA also does not apply when EPA in fact revises an applicable NAAQS.

E. Environmental Justice

Executive Order 12848 (58 FR 7629, February 11, 1994) requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. These requirements have been addressed to the extent practicable in the RIA cited in this unit.

F. Submission to Congress and the Comptroller General

Under 5 U.S.C. 801(a)(1)(A), as added by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in this issue of the **Federal Register**. This rule is a ''major rule'' for purposes of SBREFA.

IX. Response to Petition for Administrator Browner's Rescusal

On March 13, 1997, the Washington Legal Foundation (WLF), filed a petition with EPA asking that I, Carol Browner, disqualify myself in rulemaking regarding the NAAQS for PM and ozone. The petition claims that my public statements indicate a ''clear and convincing showing'' that I had ''already decided to revise the NAAQS for PM and ozone'' and that I therefore ''could not give meaningful consideration'' to comments adverse to the proposed rule. On May 12, 1997, EPA's General Counsel, Jonathan Z. Cannon, sent a letter to WLF regarding the petition. This letter and the WLF petition were then placed in the dockets for the proposed ozone and PM standards pending ''consideration and final response in connection with the Agency's final actions.''

Contrary to WLF's assertions, I have maintained an open mind throughout these proceedings, and have based today's decisions on the rulemaking record—including consideration of comments opposed to the proposal. The law does not require the Administrator of EPA to disqualify herself merely for expressing views on a proposed regulation; in fact, it is part of my responsibility to engage in the public debate on the proposals. Moreover, the assertions in WLF's petition do not accurately represent my views. The petition takes quotes out of context and repeatedly misinterprets my statements. For example, WLF quotes a statement that I made at the Children's Environmental Health Network Research Conference as an indication that I had ''prejudged the issue.'' However, my statement that ''I will not be swayed'' did not refer to adopting the NAAQS as proposed. Instead, as is clear from reviewing the entire speech, I was addressing my broader concern about children's health and the range of EPA standards affecting children's health. I also appeared at several congressional hearings and testified before members of Congress, some of whom were strongly opposed to the proposals. At those hearings, I explained the basis for the proposals and put forward the reasons why I concluded the proposals were appropriate, given the information before me at the time. At the same time, I made clear that I took very seriously

[101] One commenter argued that in reviewing the SO_2 NAAQS, EPA determined that it need not revise the $S0_2$ NAAQS, but could instead pursue an alternative regulatory program under other authority. This commenter argued that EPA has similar flexibility in reviewing the PM and Ozone NAAQS, and thus UMRA requires EPA to identify the least burdensome alternative (such as retaining the current NAAQS) as part of that process. As discussed more fully in Unit IV. of this preamble, EPA does not agree that it has flexibility to choose such an alternative; nor does EPA agree with the commenter's characterization of the action it took in deciding not to revise the SO_2 NAAQS. In fact, in deciding not to revise the SO_2 NAAQS, EPA determined, for reasons independent of section 303 of the Clean Air Act that a NAAQS revision was not warranted. See 61 FR 25566, 25575 (May 22, 1996).

my obligation to keep an open mind, and to consider fully and fairly all significant comments that the Agency received. For these reasons and others, as set forth in Mr. Cannon's May 12, 1997 response to WLF, which I adopt in full, I have decided not to recuse myself from any aspect of considering revisions to the NAAQS for ozone and PM. Accordingly, I am hereby denying WLF's petition.

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List of Subjects in 40 CFR Part 50

Environmental protection, Air pollution control, Carbon monoxide, Lead, Nitrogen dioxide, Ozone, Particulate matter, Sulfur oxides.

Dated: July 16, 1997.

Carol M. Browner,

Administrator.

Therefore, 40 CFR Chapter I is amended as follows:

PART 50—NATIONAL PRIMARY AND SECONDARY AMBIENT AIR QUALITY STANDARDS

1. The authority citation for part 50 continues to read as follows:

Authority: Secs. 109 and 301(a), Clean Air Act, as amended (42 U.S.C. 7409, 7601(a)).

2. Section 50.3 is revised to read as follows:

§ 50.3 Reference conditions.

All measurements of air quality that are expressed as mass per unit volume (e.g., micrograms per cubic meter) other than for the particulate matter (PM_{10} and $PM_{2.5}$) standards contained in § 50.7 shall be corrected to a reference temperature of 25 °C and a reference pressure of 760 millimeters of mercury (1,013.2 millibars). Measurements of PM_{10} and $PM_{2.5}$ for purposes of comparison to the standards contained in § 50.7 shall be reported based on actual ambient air volume measured at the actual ambient temperature and pressure at the monitoring site during the measurement period.

3. Section 50.6 is amended by revising the section heading and adding paragraph (d) to read as follows:

§ 50.6 National primary and secondary ambient air quality standards for PM_{10}.

* * * * *

(d) The PM_{10} standards set forth in this section will no longer apply to an area not attaining these standards as of September 16, 1997, once EPA takes final action to promulgate a rule pursuant to section 172(e) of the Clean Air Act, as amended (42 U.S.C. 7472(e)) applicable to the area. The PM_{10} standards set forth in this section will no longer apply to an area attaining these standards as of September 16, 1997, once EPA approves a State Implementation Plan (SIP) applicable to the area containing all PM_{10} control measures adopted and implemented by the state prior to September 16, 1997, and a section 110 SIP implementing the PM standards published on July 18, 1997. SIP approvals are codified in 40 CFR part 52.

4. Section 50.7 is added to read as follows:

§ 50.7 National primary and secondary ambient air quality standards for particulate matter.

(a) The national primary and secondary ambient air quality standards for particulate matter are:

(1) 15.0 micrograms per cubic meter ($\mu g/m^3$) annual arithmetic mean concentration, and 65 $\mu g/m^3$ 24-hour average concentration measured in the ambient air as $PM_{2.5}$ (particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers) by either:

(i) A reference method based on Appendix L of this part and designated in accordance with part 53 of this chapter; or

(ii) An equivalent method designated in accordance with part 53 of this chapter.

(2) 50 micrograms per cubic meter ($\mu g/m^3$) annual arithmetic mean

concentration, and 150 μg/m^3 24-hour average concentration measured in the ambient air as PM_{10} (particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers) by either:

(i) A reference method based on Appendix M of this part and designated in accordance with part 53 of this chapter; or

(ii) An equivalent method designated in accordance with part 53 of this chapter.

(b) The annual primary and secondary $PM_{2.5}$ standards are met when the annual arithmetic mean concentration, as determined in accordance with Appendix N of this part, is less than or equal to 15.0 micrograms per cubic meter.

(c) The 24-hour primary and secondary $PM_{2.5}$ standards are met when the 98th percentile 24-hour concentration, as determined in accordance with Appendix N of this part, is less than or equal to 65 micrograms per cubic meter.

(d) The annual primary and secondary PM_{10} standards are met when the annual arithmetic mean concentration, as determined in accordance with Appendix N of this part, is less than or equal to 50 micrograms per cubic meter.

(e) The 24-hour primary and secondary PM_{10} standards are met when the 99th percentile 24-hour concentration, as determined in accordance with Appendix N of this part, is less than or equal to 150 micrograms per cubic meter.

5. Appendix K is revised (for conformity with the format of the other appendices in this part) to read as follows:

Appendix K to Part 50—Interpretation of the National Ambient Air Quality Standards for Particulate Matter

1.0 *General.*

(a) This appendix explains the computations necessary for analyzing particulate matter data to determine attainment of the 24-hour and annual standards specified in 40 CFR 50.6. For the primary and secondary standards, particulate matter is measured in the ambient air as PM_{10} (particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers) by a reference method based on appendix J of this part and designated in accordance with part 53 of this chapter, or by an equivalent method designated in accordance with part 53 of this chapter. The required frequency of measurements is specified in part 58 of this chapter.

(b) The terms used in this appendix are defined as follows:

Average refers to an arithmetic mean. All particulate matter standards are expressed in terms of expected annual values: Expected number of exceedances per year for the 24-hour standards and expected annual arithmetic mean for the annual standards.

Daily value for PM_{10} refers to the 24-hour average concentration of PM_{10} calculated or measured from midnight to midnight (local time).

Exceedance means a daily value that is above the level of the 24-hour standard after rounding to the nearest 10 μg/m^3 (i.e., values ending in 5 or greater are to be rounded up).

Expected annual value is the number approached when the annual values from an increasing number of years are averaged, in the absence of long-term trends in emissions or meteorological conditions.

Year refers to a calendar year.

(c) Although the discussion in this appendix focuses on monitored data, the same principles apply to modeling data, subject to EPA modeling guidelines.

2.0 *Attainment Determinations.*

2.1 *24-Hour Primary and Secondary Standards.*

(a) Under 40 CFR 50.6(a) the 24-hour primary and secondary standards are attained when the expected number of exceedances per year at each monitoring site is less than or equal to one. In the simplest case, the number of expected exceedances at a site is determined by recording the number of exceedances in each calendar year and then averaging them over the past 3 calendar years. Situations in which 3 years of data are not available and possible adjustments for unusual events or trends are discussed in sections 2.3 and 2.4 of this appendix. Further, when data for a year are incomplete, it is necessary to compute an estimated number of exceedances for that year by adjusting the observed number of exceedances. This procedure, performed by calendar quarter, is described in section 3.0 of this appendix. The expected number of exceedances is then estimated by averaging the individual annual estimates for the past 3 years.

(b) The comparison with the allowable expected exceedance rate of one per year is made in terms of a number rounded to the nearest tenth (fractional values equal to or greater than 0.05 are to be rounded up; e.g., an exceedance rate of 1.05 would be rounded to 1.1, which is the lowest rate for nonattainment).

2.2 *Annual Primary and Secondary Standards.* Under 40 CFR 50.6(b), the annual primary and secondary standards are attained when the expected annual arithmetic mean PM_{10} concentration is less than or equal to the level of the standard. In the simplest case, the expected annual arithmetic mean is determined by averaging the annual arithmetic mean PM_{10} concentrations for the past 3 calendar years. Because of the potential for incomplete data and the possible seasonality in PM_{10} concentrations, the annual mean shall be calculated by averaging the four quarterly means of PM_{10} concentrations within the calendar year. The equations for calculating the annual arithmetic mean are given in section 4.0 of this appendix. Situations in which 3 years of data are not available and possible adjustments for unusual events or trends are discussed in sections 2.3 and 2.4 of this appendix. The expected annual arithmetic mean is rounded to the nearest 1 μg/m^3 before comparison with the annual standards (fractional values equal to or greater than 0.5 are to be rounded up).

2.3 *Data Requirements.*

(a) 40 CFR 58.13 specifies the required minimum frequency of sampling for PM_{10}. For the purposes of making comparisons with the particulate matter standards, all data produced by National Air Monitoring Stations (NAMS), State and Local Air Monitoring Stations (SLAMS) and other sites submitted to EPA in accordance with the Part 58 requirements must be used, and a minimum of 75 percent of the scheduled PM_{10} samples per quarter are required.

(b) To demonstrate attainment of either the annual or 24-hour standards at a monitoring site, the monitor must provide sufficient data to perform the required calculations of sections 3.0 and 4.0 of this appendix. The amount of data required varies with the sampling frequency, data capture rate and the number of years of record. In all cases, 3 years of representative monitoring data that meet the 75 percent criterion of the previous paragraph should be utilized, if available, and would suffice. More than 3 years may be considered, if all additional representative years of data meeting the 75 percent criterion are utilized. Data not meeting these criteria may also suffice to show attainment; however, such exceptions will have to be approved by the appropriate Regional Administrator in accordance with EPA guidance.

(c) There are less stringent data requirements for showing that a monitor has failed an attainment test and thus has recorded a violation of the particulate matter standards. Although it is generally necessary to meet the minimum 75 percent data capture requirement per quarter to use the computational equations described in sections 3.0 and 4.0 of this appendix, this criterion does not apply when less data is sufficient to unambiguously establish nonattainment. The following examples illustrate how nonattainment can be demonstrated when a site fails to meet the completeness criteria. Nonattainment of the 24-hour primary standards can be established by the observed annual number of exceedances (e.g., four observed exceedances in a single year), or by the estimated number of exceedances derived from the observed number of exceedances and the required number of scheduled samples (e.g., two observed exceedances with every other day sampling). Nonattainment of the annual standards can be demonstrated on the basis of quarterly mean concentrations developed from observed data combined with one-half the minimum detectable concentration substituted for missing values. In both cases, expected annual values must exceed the levels allowed by the standards.

2.4 *Adjustment for Exceptional Events and Trends.*

(a) An exceptional event is an uncontrollable event caused by natural sources of particulate matter or an event that is not expected to recur at a given location. Inclusion of such a value in the computation of exceedances or averages could result in inappropriate estimates of their respective expected annual values. To reduce the effect of unusual events, more than 3 years of

representative data may be used. Alternatively, other techniques, such as the use of statistical models or the use of historical data could be considered so that the event may be discounted or weighted according to the likelihood that it will recur. The use of such techniques is subject to the approval of the appropriate Regional Administrator in accordance with EPA guidance.

(b) In cases where long–term trends in emissions and air quality are evident, mathematical techniques should be applied to account for the trends to ensure that the expected annual values are not inappropriately biased by unrepresentative data. In the simplest case, if 3 years of data are available under stable emission conditions, this data should be used. In the event of a trend or shift in emission patterns, either the most recent representative year(s) could be used or statistical techniques or models could be used in conjunction with previous years of data to adjust for trends. The use of less than 3 years of data, and any adjustments are subject to the approval of the appropriate Regional Administrator in accordance with EPA guidance.

3.0 *Computational Equations for the 24-hour Standards.*

3.1 *Estimating Exceedances for a Year.*

(a) If PM_{10} sampling is scheduled less frequently than every day, or if some scheduled samples are missed, a PM_{10} value will not be available for each day of the year. To account for the possible effect of incomplete data, an adjustment must be made to the data collected at each monitoring location to estimate the number of exceedances in a calendar year. In this adjustment, the assumption is made that the fraction of missing values that would have exceeded the standard level is identical to the fraction of measured values above this level. This computation is to be made for all sites that are scheduled to monitor throughout the entire year and meet the minimum data requirements of section 2.3 of this appendix. Because of possible seasonal imbalance, this adjustment shall be applied on a quarterly basis. The estimate of the expected number of exceedances for the quarter is equal to the observed number of exceedances plus an increment associated with the missing data. The following equation must be used for these computations:

Equation 1

$$e_q = v_q + \left[\left(v_q/n_q\right)\times\left(N_q - n_q\right)\right] = v_q \times N_q/n_q$$

where:

e_q=the estimated number of exceedances for calendar quarter q;

v_q=the observed number of exceedances for calendar quarter q;

N_q=the number of days in calendar quarter q;

n_q=the number of days in calendar quarter q with PM_{10} data; and

q=the index for calendar quarter, q=1, 2, 3 or 4.

(b) The estimated number of exceedances for a calendar quarter must be rounded to the nearest hundredth (fractional values equal to or greater than 0.005 must be rounded up).

(c) The estimated number of exceedances for the year, e, is the sum of the estimates for each calendar quarter.

Equation 2

$$e = \sum_{q=1}^{4} e_q$$

(d) The estimated number of exceedances for a single year must be rounded to one decimal place (fractional values equal to or greater than 0.05 are to be rounded up). The expected number of exceedances is then estimated by averaging the individual annual estimates for the most recent 3 or more representative years of data. The expected number of exceedances must be rounded to one decimal place (fractional values equal to or greater than 0.05 are to be rounded up).

(e) The adjustment for incomplete data will not be necessary for monitoring or modeling data which constitutes a complete record, i.e., 365 days per year.

(f) To reduce the potential for overestimating the number of expected exceedances, the correction for missing data will not be required for a calendar quarter in which the first observed exceedance has occurred if:

(1) There was only one exceedance in the calendar quarter;

(2) Everyday sampling is subsequently initiated and maintained for 4 calendar quarters in accordance with 40 CFR 58.13; and

(3) Data capture of 75 percent is achieved during the required period of everyday sampling. In addition, if the first exceedance is observed in a calendar quarter in which the monitor is already sampling every day, no adjustment for missing data will be made to the first exceedance if a 75 percent data capture rate was achieved in the quarter in which it was observed.

Example 1

a. During a particular calendar quarter, 39 out of a possible 92 samples were recorded, with one observed exceedance of the 24-hour standard. Using Equation 1, the estimated number of exceedances for the quarter is:

e_q=1×92/39=2.359 or 2.36.

b. If the estimated exceedances for the other 3 calendar quarters in the year were 2.30, 0.0 and 0.0, then, using Equation 2, the estimated number of exceedances for the year is 2.36+2.30+0.0+0.0 which equals 4.66 or 4.7. If no exceedances were observed for the 2 previous years, then the expected number of exceedances is estimated by: (1/3)×(4.7+0+0)=1.57 or 1.6. Since 1.6 exceeds the allowable number of expected exceedances, this monitoring site would fail the attainment test.

Example 2

In this example, everyday sampling was initiated following the first observed exceedance as required by 40 CFR 58.13. Accordingly, the first observed exceedance would not be adjusted for incomplete sampling. During the next three quarters, 1.2 exceedances were estimated. In this case, the estimated exceedances for the year would be 1.0+1.2+0.0+0.0 which equals 2.2. If, as before, no exceedances were observed for the two previous years, then the estimated exceedances for the 3–year period would then be (1/3)×(2.2+0.0+0.0)=0.7, and the monitoring site would *not* fail the attainment test.

3.2 *Adjustments for Non-Scheduled Sampling Days.*

(a) If a systematic sampling schedule is used and sampling is performed on days in addition to the days specified by the systematic sampling schedule, e.g., during episodes of high pollution, then an adjustment must be made in the eqution for the estimation of exceedances. Such an adjustment is needed to eliminate the bias in the estimate of the quarterly and annual number of exceedances that would occur if the chance of an exceedance is different for scheduled than for non-scheduled days, as would be the case with episode sampling.

(b) The required adjustment treats the systematic sampling schedule as a stratified sampling plan. If the period from one scheduled sample until the day preceding the next scheduled sample is defined as a sampling stratum, then there is one stratum for each scheduled sampling day. An average number of observed exceedances is computed for each of these sampling strata. With nonscheduled sampling days, the estimated number of exceedances is defined as:

Equation 3

$$e_q = \left(N_q/m_q\right)\times\sum_{j=1}^{m_q}\left(v_j/k_j\right)$$

where:

e_q=the estimated number of exceedances for the quarter;

N_q=the number of days in the quarter;

m_q=the number of strata with samples during the quarter;

v_j=the number of observed exceedances in stratum j; and

k_j=the number of actual samples in stratum j.

(c) Note that if only one sample value is recorded in each stratum, then Equation 3 reduces to Equation 1.

Example 3

A monitoring site samples according to a systematic sampling schedule of one sample every 6 days, for a total of 15 scheduled samples in a quarter out of a total of 92 possible samples. During one 6-day period, potential episode levels of PM_{10} were suspected, so 5 additional samples were taken. One of the regular scheduled samples was missed, so a total of 19 samples in 14 sampling strata were measured. The one 6-day sampling stratum with 6 samples recorded 2 exceedances. The remainder of the quarter with one sample per stratum recorded zero exceedances. Using Equation 3, the estimated number of exceedances for the quarter is:

e_q=(92/14)×(2/6+0+. . .+0)=2.19.

4.0 *Computational Equations for Annual Standards.*

4.1 *Calculation of the Annual Arithmetic Mean.* (a) An annual arithmetic mean value for PM_{10} is determined by averaging the quarterly means for the 4 calendar quarters of the year. The following equation is to be used for calculation of the mean for a calendar quarter:

Equation 4

$$\bar{x}_q = \left(1/n_q\right) \times \sum_{i=1}^{n_q} x_i$$

where:

$\bar{x}_q$= the quarterly mean concentration for quarter q, q=1, 2, 3, or 4,

n_q= the number of samples in the quarter, and

x_i= the ith concentration value recorded in the quarter.

(b) The quarterly mean, expressed in μg/m^3, must be rounded to the nearest tenth (fractional values of 0.05 should be rounded up).

(c) The annual mean is calculated by using the following equation:

Equation 5

$$\bar{x} = \left(1/4\right) \times \sum_{q=1}^{4} \bar{x}_q$$

where:

$\bar{x}$=the annual mean; and

$\bar{x}_q$=the mean for calendar quarter q.

(d) The average of quarterly means must be rounded to the nearest tenth (fractional values of 0.05 should be rounded up).

(e) The use of quarterly averages to compute the annual average will not be necessary for monitoring or modeling data which results in a complete record, i.e., 365 days per year.

(f) The expected annual mean is estimated as the average of three or more annual means. This multi-year estimate, expressed in μg/m^3, shall be rounded to the nearest integer for comparison with the annual standard (fractional values of 0.5 should be rounded up).

Example 4

Using Equation 4, the quarterly means are calculated for each calendar quarter. If the quarterly means are 52.4, 75.3, 82.1, and 63.2 μg/m^3, then the annual mean is:

$\bar{x}$ = (1/4)×(52.4+75.3+82.1+63.2)= 68.25 or 68.3.

4.2 *Adjustments for Non-scheduled Sampling Days.* (a) An adjustment in the calculation of the annual mean is needed if sampling is performed on days in addition to the days specified by the systematic sampling schedule. For the same reasons given in the discussion of estimated exceedances, under section 3.2 of this appendix, the quarterly averages would be calculated by using the following equation:

Equation 6

$$\bar{x}_q = \left(1/m_q\right) \times \sum_{j=1}^{m_q} \sum_{i=1}^{k_j} \left(x_{ij}/k_j\right)$$

where:

$\bar{x}_q$=the quarterly mean concentration for quarter q, q=1, 2, 3, or 4;

x_{ij}=the ith concentration value recorded in stratum j;

k_j=the number of actual samples in stratum j; and

m_q=the number of strata with data in the quarter.

(b) If one sample value is recorded in each stratum, Equation 6 reduces to a simple arithmetic average of the observed values as described by Equation 4.

Example 5

a. During one calendar quarter, 9 observations were recorded. These samples were distributed among 7 sampling strata, with 3 observations in one stratum. The concentrations of the 3 observations in the single stratum were 202, 242, and 180 μg/m^3. The remaining 6 observed concentrations were 55, 68, 73, 92, 120, and 155 μg/m^3. Applying the weighting factors specified in Equation 6, the quarterly mean is:

$\bar{x}_q$ = (1/7) × [(1/3) × (202 + 242 + 180) + 155 + 68 + 73 + 92 + 120 + 155] = 110.1

b. Although 24–hour measurements are rounded to the nearest 10 μg/m^3 for determinations of exceedances of the 24–hour standard, note that these values are rounded to the nearest 1 μg/m^3 for the calculation of means.

6. Appendix L is added to read as follows:

Appendix L to Part 50—Reference Method For the Determination of Fine Particulate Matter as $PM_{2.5}$ in the Atmosphere

1.0 *Applicability.*

1.1 This method provides for the measurement of the mass concentration of fine particulate matter having an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$) in ambient air over a 24-hour period for purposes of determining whether the primary and secondary national ambient air quality standards for fine particulate matter specified in § 50.6 of this part are met. The measurement process is considered to be nondestructive, and the $PM_{2.5}$ sample obtained can be subjected to subsequent physical or chemical analyses. Quality assessment procedures are provided in part 58, Appendix A of this chapter, and quality assurance guidance are provided in references 1, 2, and 3 in section 13.0 of this appendix.

1.2 This method will be considered a reference method for purposes of part 58 of this chapter only if:

(a) The associated sampler meets the requirements specified in this appendix and the applicable requirements in part 53 of this chapter, and

(b) The method and associated sampler have been designated as a reference method in accordance with part 53 of this chapter.

1.3 $PM_{2.5}$ samplers that meet nearly all specifications set forth in this method but have minor deviations and/or modifications of the reference method sampler will be designated as ''Class I'' equivalent methods for $PM_{2.5}$ in accordance with part 53 of this chapter.

2.0 *Principle.*

2.1 An electrically powered air sampler draws ambient air at a constant volumetric flow rate into a specially shaped inlet and through an inertial particle size separator (impactor) where the suspended particulate matter in the $PM_{2.5}$ size range is separated for collection on a polytetrafluoroethylene (PTFE) filter over the specified sampling period. The air sampler and other aspects of this reference method are specified either explicitly in this appendix or generally with reference to other applicable regulations or quality assurance guidance.

2.2 Each filter is weighed (after moisture and temperature conditioning) before and after sample collection to determine the net gain due to collected $PM_{2.5}$. The total volume of air sampled is determined by the sampler from the measured flow rate at actual ambient temperature and pressure and the sampling time. The mass concentration of $PM_{2.5}$ in the ambient air is computed as the total mass of collected particles in the $PM_{2.5}$ size range divided by the actual volume of air sampled, and is expressed in micrograms per cubic meter of air (μg/m^3).

3.0 *$PM_{2.5}$ Measurement Range.*

3.1 *Lower concentration limit.* The lower detection limit of the mass concentration measurement range is estimated to be approximately 2 μg/am^3, based on noted mass changes in field blanks in conjunction with the 24 m^3 nominal total air sample volume specified for the 24-hour sample.

3.2 *Upper concentration limit.* The upper limit of the mass concentration range is determined by the filter mass loading beyond which the sampler can no longer maintain the operating flow rate within specified limits due to increased pressure drop across the loaded filter. This upper limit cannot be specified precisely because it is a complex function of the ambient particle size distribution and type, humidity, the individual filter used, the capacity of the sampler flow rate control system, and perhaps other factors. Nevertheless, all samplers are estimated to be capable of measuring 24-hour $PM_{2.5}$ mass concentrations of at least 200 μg/m^3 while maintaining the operating flow rate within the specified limits.

3.3 *Sample period.* The required sample period for $PM_{2.5}$ concentration measurements by this method shall be 1,380 to 1500 minutes (23 to 25 hours). However, when a sample period is less than 1,380 minutes, the measured concentration (as determined by the collected $PM_{2.5}$ mass divided by the actual sampled air volume), multiplied by the actual number of minutes in the sample period and divided by 1,440, may be used as if it were a valid concentration measurement for the specific purpose of determining a violation of the NAAQS. This value assumes

that the $PM_{2.5}$ concentration is zero for the remaining portion of the sample period and therefore represents the minimum concentration that could have been measured for the full 24-hour sample period. Accordingly, if the value thus calculated is high enough to be an exceedance, such an exceedance would be a valid exceedance for the sample period. When reported to AIRS, this data value should receive a special code to identify it as not to be commingled with normal concentration measurements or used for other purposes.

4.0 *Accuracy.*

4.1 Because the size and volatility of the particles making up ambient particulate matter vary over a wide range and the mass concentration of particles varies with particle size, it is difficult to define the accuracy of $PM_{2.5}$ measurements in an absolute sense. The accuracy of $PM_{2.5}$ measurements is therefore defined in a relative sense, referenced to measurements provided by this reference method. Accordingly, accuracy shall be defined as the degree of agreement between a subject field $PM_{2.5}$ sampler and a collocated $PM_{2.5}$ reference method audit sampler operating simultaneously at the monitoring site location of the subject sampler and includes both random (precision) and systematic (bias) errors. The requirements for this field sampler audit procedure are set forth in part 58, Appendix A of this chapter.

4.2 Measurement system bias. Results of collocated measurements where the duplicate sampler is a reference method sampler are used to assess a portion of the measurement system bias according to the schedule and procedure specified in part 58, Appendix A of this chapter.

4.3 Audits with reference method samplers to determine system accuracy and bias. According to the schedule and procedure specified in part 58, Appendix A of this chapter, a reference method sampler is required to be located at each of selected $PM_{2.5}$ SLAMS sites as a duplicate sampler. The results from the primary sampler and the duplicate reference method sampler are used to calculate accuracy of the primary sampler on a quarterly basis, bias of the primary sampler on an annual basis, and bias of a single reporting organization on an annual basis. Reference 2 in section 13.0 of this appendix provides additional information and guidance on these reference method audits.

4.4 Flow rate accuracy and bias. Part 58, Appendix A of this chapter requires that the flow rate accuracy and bias of individual $PM_{2.5}$ samplers used in SLAMS monitoring networks be assessed periodically via audits of each sampler's operational flow rate. In addition, part 58, Appendix A of this chapter requires that flow rate bias for each reference and equivalent method operated by each reporting organization be assessed quarterly and annually. Reference 2 in section 13.0 of this appendix provides additional information and guidance on flow rate accuracy audits and calculations for accuracy and bias.

5.0 *Precision.* A data quality objective of 10 percent coefficient of variation or better has been established for the operational precision of $PM_{2.5}$ monitoring data.

5.1 Tests to establish initial operational precision for each reference method sampler are specified as a part of the requirements for designation as a reference method under § 53.58 of this chapter.

5.2 Measurement System Precision. Collocated sampler results, where the duplicate sampler is not a reference method sampler but is a sampler of the same designated method as the primary sampler, are used to assess measurement system precision according to the schedule and procedure specified in part 58, Appendix A of this chapter. Part 58, Appendix A of this chapter requires that these collocated sampler measurements be used to calculate quarterly and annual precision estimates for each primary sampler and for each designated method employed by each reporting organization. Reference 2 in section 13.0 of this appendix provides additional information and guidance on this requirement.

6.0 *Filter for $PM_{2.5}$ Sample Collection.* Any filter manufacturer or vendor who sells or offers to sell filters specifically identified for use with this $PM_{2.5}$ reference method shall certify that the required number of filters from each lot of filters offered for sale as such have been tested as specified in this section 6.0 and meet all of the following design and performance specifications.

6.1 *Size.* Circular, 46.2 mm diameter ±0.25 mm.

6.2 *Medium.* Polytetrafluoroethylene (PTFE Teflon), with integral support ring.

6.3 *Support ring.* Polymethylpentene (PMP) or equivalent inert material, 0.38 ±0.04 mm thick, outer diameter 46.2 mm ±0.25 mm, and width of 3.68 mm (±0.00, -0.51 mm).

6.4 *Pore size.* 2 µm as measured by ASTM F 316–94.

6.5 *Filter thickness.* 30 to 50 µm.

6.6 *Maximum pressure drop (clean filter).* 30 cm H_2O column @ 16.67 L/min clean air flow.

6.7 *Maximum moisture pickup.* Not more than 10 µg weight increase after 24-hour exposure to air of 40 percent relative humidity, relative to weight after 24-hour exposure to air of 35 percent relative humidity.

6.8 *Collection efficiency.* Greater than 99.7 percent, as measured by the DOP test (ASTM D 2986–91) with 0.3 µm particles at the sampler's operating face velocity.

6.9 *Filter weight stability.* Filter weight loss shall be less than 20 µg, as measured in each of the following two tests specified in sections 6.9.1 and 6.9.2 of this appendix. The following conditions apply to both of these tests: Filter weight loss shall be the average difference between the initial and the final filter weights of a random sample of test filters selected from each lot prior to sale. The number of filters tested shall be not less than 0.1 percent of the filters of each manufacturing lot, or 10 filters, whichever is greater. The filters shall be weighed under laboratory conditions and shall have had no air sample passed through them, i.e., filter blanks. Each test procedure must include initial conditioning and weighing, the test, and final conditioning and weighing. Conditioning and weighing shall be in accordance with sections 8.0 through 8.2 of this appendix and general guidance provided in reference 2 of section 13.0 of this appendix.

6.9.1 *Test for loose, surface particle contamination.* After the initial weighing, install each test filter, in turn, in a filter cassette (Figures L–27, L–28, and L–29 of this appendix) and drop the cassette from a height of 25 cm to a flat hard surface, such as a particle-free wood bench. Repeat two times, for a total of three drop tests for each test filter. Remove the test filter from the cassette and weigh the filter. The average change in weight must be less than 20 µg.

6.9.2 *Test for temperature stability.* After weighing each filter, place the test filters in a drying oven set at 40 °C ±2 °C for not less than 48 hours. Remove, condition, and reweigh each test filter. The average change in weight must be less than 20 µg.

6.10 *Alkalinity.* Less than 25 microequivalents/gram of filter, as measured by the guidance given in reference 2 in section 13.0 of this appendix.

6.11 *Supplemental requirements.* Although not required for determination of $PM_{2.5}$ mass concentration under this reference method, additional specifications for the filter must be developed by users who intend to subject $PM_{2.5}$ filter samples to subsequent chemical analysis. These supplemental specifications include background chemical contamination of the filter and any other filter parameters that may be required by the method of chemical analysis. All such supplemental filter specifications must be compatible with and secondary to the primary filter specifications given in this section 6.0 of this appendix.

7.0 *$PM_{2.5}$ Sampler.*

7.1 *Configuration.* The sampler shall consist of a sample air inlet, downtube, particle size separator (impactor), filter holder assembly, air pump and flow rate control system, flow rate measurement device, ambient and filter temperature monitoring system, barometric pressure measurement system, timer, outdoor environmental enclosure, and suitable mechanical, electrical, or electronic control capability to meet or exceed the design and functional performance as specified in this section 7.0 of this appendix. The performance specifications require that the sampler:

(a) Provide automatic control of sample volumetric flow rate and other operational parameters.

(b) Monitor these operational parameters as well as ambient temperature and pressure.

(c) Provide this information to the sampler operator at the end of each sample period in digital form, as specified in Table L–1 of section 7.4.19 of this appendix.

7.2 *Nature of specifications.* The $PM_{2.5}$ sampler is specified by a combination of design and performance requirements. The sample inlet, downtube, particle size discriminator, filter cassette, and the internal configuration of the filter holder assembly are specified explicitly by design figures and associated mechanical dimensions, tolerances, materials, surface finishes, assembly instructions, and other necessary specifications. All other aspects of the

sampler are specified by required operational function and performance, and the design of these other aspects (including the design of the lower portion of the filter holder assembly) is optional, subject to acceptable operational performance. Test procedures to demonstrate compliance with both the design and performance requirements are set forth in subpart E of part 53 of this chapter.

7.3 *Design specifications.* Except as indicated in this section 7.3 of this appendix, these components must be manufactured or reproduced exactly as specified, in an ISO 9001-registered facility, with registration initially approved and subsequently maintained during the period of manufacture. See § 53.1(t) of this chapter for the definition of an ISO-registered facility. Minor modifications or variances to one or more components that clearly would not affect the aerodynamic performance of the inlet, downtube, impactor, or filter cassette will be considered for specific approval. Any such proposed modifications shall be described and submitted to the EPA for specific individual acceptability either as part of a reference or equivalent method application under part 53 of this chapter or in writing in advance of such an intended application under part 53 of this chapter.

7.3.1 *Sample inlet assembly.* The sample inlet assembly, consisting of the inlet, downtube, and impactor shall be configured and assembled as indicated in Figure L–1 of this appendix and shall meet all associated requirements. A portion of this assembly shall also be subject to the maximum overall sampler leak rate specification under section 7.4.6 of this appendix.

7.3.2 *Inlet.* The sample inlet shall be fabricated as indicated in Figures L–2 through L–18 of this appendix and shall meet all associated requirements.

7.3.3 *Downtube.* The downtube shall be fabricated as indicated in Figure L–19 of this appendix and shall meet all associated requirements.

7.3.4 *Impactor.*

7.3.4.1 The impactor (particle size separator) shall be fabricated as indicated in Figures L–20 through L–24 of this appendix and shall meet all associated requirements. Following the manufacture and finishing of each upper impactor housing (Figure L–21 of this appendix), the dimension of the impaction jet must be verified by the manufacturer using Class ZZ go/no-go plug gauges that are traceable to NIST.

7.3.4.2 Impactor filter specifications:

(a) Size. Circular, 35 to 37 mm diameter.

(b) Medium. Borosilicate glass fiber, without binder.

(c) Pore size. 1 to 1.5 micrometer, as measured by ASTM F 316–80.

(d) Thickness. 300 to 500 micrometers.

7.3.4.3 Impactor oil specifications:

(a) Composition. Tetramethyltetraphenyltrisiloxane, single-compound diffusion oil.

(b) Vapor pressure. Maximum 2 x 10^{-8} mm Hg at 25 °C.

(c) Viscosity. 36 to 40 centistokes at 25 °C.

(d) Density. 1.06 to 1.07 g/cm^3 at 25 °C.

(e) Quantity. 1 mL ±0.1 mL.

7.3.5 *Filter holder assembly.* The sampler shall have a sample filter holder assembly to adapt and seal to the down tube and to hold and seal the specified filter, under section 6.0 of this appendix, in the sample air stream in a horizontal position below the downtube such that the sample air passes downward through the filter at a uniform face velocity. The upper portion of this assembly shall be fabricated as indicated in Figures L–25 and L–26 of this appendix and shall accept and seal with the filter cassette, which shall be fabricated as indicated in Figures L–27 through L–29 of this appendix.

(a) The lower portion of the filter holder assembly shall be of a design and construction that:

(1) Mates with the upper portion of the assembly to complete the filter holder assembly,

(2) Completes both the external air seal and the internal filter cassette seal such that all seals are reliable over repeated filter changings, and

(3) Facilitates repeated changing of the filter cassette by the sampler operator.

(b) Leak–test performance requirements for the filter holder assembly are included in section 7.4.6 of this appendix.

(c) If additional or multiple filters are stored in the sampler as part of an automatic sequential sample capability, all such filters, unless they are currently and directly installed in a sampling channel or sampling configuration (either active or inactive), shall be covered or (preferably) sealed in such a way as to:

(1) Preclude significant exposure of the filter to possible contamination or accumulation of dust, insects, or other material that may be present in the ambient air, sampler, or sampler ventilation air during storage periods either before or after sampling; and

(2) To minimize loss of volatile or semi-volatile PM sample components during storage of the filter following the sample period.

7.3.6 *Flow rate measurement adapter.* A flow rate measurement adapter as specified in Figure L–30 of this appendix shall be furnished with each sampler.

7.3.7 *Surface finish.* All internal surfaces exposed to sample air prior to the filter shall be treated electrolytically in a sulfuric acid bath to produce a clear, uniform anodized surface finish of not less than 1000 mg/ft^2 (1.08 mg/cm^2) in accordance with military standard specification (mil. spec.) 8625F, Type II, Class 1 in reference 4 of section 13.0 of this appendix. This anodic surface coating shall not be dyed or pigmented. Following anodization, the surfaces shall be sealed by immersion in boiling deionized water for not less than 15 minutes. Section 53.51(d)(2) of this chapter should also be consulted.

7.3.8 *Sampling height.* The sampler shall be equipped with legs, a stand, or other means to maintain the sampler in a stable, upright position and such that the center of the sample air entrance to the inlet, during sample collection, is maintained in a horizontal plane and is 2.0 ±0.2 meters above the floor or other horizontal supporting surface. Suitable bolt holes, brackets, tie-downs, or other means should be provided to facilitate mechanically securing the sample to the supporting surface to prevent toppling of the sampler due to wind.

7.4 *Performance specifications.*

7.4.1 *Sample flow rate.* Proper operation of the impactor requires that specific air velocities be maintained through the device. Therefore, the design sample air flow rate through the inlet shall be 16.67 L/min (1.000 m^3/hour) measured as actual volumetric flow rate at the temperature and pressure of the sample air entering the inlet.

7.4.2 *Sample air flow rate control system.* The sampler shall have a sample air flow rate control system which shall be capable of providing a sample air volumetric flow rate within the specified range, under section 7.4.1 of this appendix, for the specified filter, under section 6.0 of this appendix, at any atmospheric conditions specified, under section 7.4.7 of this appendix, at a filter pressure drop equal to that of a clean filter plus up to 75 cm water column (55 mm Hg), and over the specified range of supply line voltage, under section 7.4.15.1 of this appendix. This flow control system shall allow for operator adjustment of the operational flow rate of the sampler over a range of at least ±15 percent of the flow rate specified in section 7.4.1 of this appendix.

7.4.3 *Sample flow rate regulation.* The sample flow rate shall be regulated such that for the specified filter, under section 6.0 of this appendix, at any atmospheric conditions specified, under section 7.4.7 of this appendix, at a filter pressure drop equal to that of a clean filter plus up to 75 cm water column (55 mm Hg), and over the specified range of supply line voltage, under section 7.4.15.1 of this appendix, the flow rate is regulated as follows:

7.4.3.1 The volumetric flow rate, measured or averaged over intervals of not more than 5 minutes over a 24-hour period, shall not vary more than ±5 percent from the specified 16.67 L/min flow rate over the entire sample period.

7.4.3.2 The coefficient of variation (sample standard deviation divided by the mean) of the flow rate, measured over a 24-hour period, shall not be greater than 2 percent.

7.4.3.3 The amplitude of short-term flow rate pulsations, such as may originate from some types of vacuum pumps, shall be attenuated such that they do not cause significant flow measurement error or affect the collection of particles on the particle collection filter.

7.4.4 *Flow rate cut off.* The sampler's sample air flow rate control system shall terminate sample collection and stop all sample flow for the remainder of the sample period in the event that the sample flow rate deviates by more than 10 percent from the sampler design flow rate specified in section 7.4.1 of this appendix for more than 60 seconds. However, this sampler cut-off provision shall not apply during periods when the sampler is inoperative due to a temporary power interruption, and the elapsed time of the inoperative period shall not be included in the total sample time measured and reported by the sampler, under section 7.4.13 of this appendix.

7.4.5 *Flow rate measurement.*

7.4.5.1 The sampler shall provide a means to measure and indicate the instantaneous sample air flow rate, which shall be measured as volumetric flow rate at the

temperature and pressure of the sample air entering the inlet, with an accuracy of ±2 percent. The measured flow rate shall be available for display to the sampler operator at any time in either sampling or standby modes, and the measurement shall be updated at least every 30 seconds. The sampler shall also provide a simple means by which the sampler operator can manually start the sample flow temporarily during non-sampling modes of operation, for the purpose of checking the sample flow rate or the flow rate measurement system.

7.4.5.2 During each sample period, the sampler's flow rate measurement system shall automatically monitor the sample volumetric flow rate, obtaining flow rate measurements at intervals of not greater than 30 seconds.

(a) Using these interval flow rate measurements, the sampler shall determine or calculate the following flow-related parameters, scaled in the specified engineering units:

(1) The instantaneous or interval-average flow rate, in L/min.

(2) The value of the average sample flow rate for the sample period, in L/min.

(3) The value of the coefficient of variation (sample standard deviation divided by the average) of the sample flow rate for the sample period, in percent.

(4) The occurrence of any time interval during the sample period in which the measured sample flow rate exceeds a range of ±5 percent of the average flow rate for the sample period for more than 5 minutes, in which case a warning flag indicator shall be set.

(5) The value of the integrated total sample volume for the sample period, in m^3.

(b) Determination or calculation of these values shall properly exclude periods when the sampler is inoperative due to temporary interruption of electrical power, under section 7.4.13 of this appendix, or flow rate cut off, under section 7.4.4 of this appendix.

(c) These parameters shall be accessible to the sampler operator as specified in Table L–1 of section 7.4.19 of this appendix. In addition, it is strongly encouraged that the flow rate for each 5-minute interval during the sample period be available to the operator following the end of the sample period.

7.4.6 *Leak test capability.*

7.4.6.1 *External leakage.* The sampler shall include an external air leak-test capability consisting of components, accessory hardware, operator interface controls, a written procedure in the associated Operation/Instruction Manual, under section 7.4.18 of this appendix, and all other necessary functional capability to permit and facilitate the sampler operator to conveniently carry out a leak test of the sampler at a field monitoring site without additional equipment. The sampler components to be subjected to this leak test include all components and their interconnections in which external air leakage would or could cause an error in the sampler's measurement of the total volume of sample air that passes through the sample filter.

(a) The suggested technique for the operator to use for this leak test is as follows:

(1) Remove the sampler inlet and installs the flow rate measurement adapter supplied with the sampler, under section 7.3.6 of this appendix.

(2) Close the valve on the flow rate measurement adapter and use the sampler air pump to draw a partial vacuum in the sampler, including (at least) the impactor, filter holder assembly (filter in place), flow measurement device, and interconnections between these devices, of at least 55 mm Hg (75 cm water column), measured at a location downstream of the filter holder assembly.

(3) Plug the flow system downstream of these components to isolate the components under vacuum from the pump, such as with a built-in valve.

(4) Stop the pump.

(5) Measure the trapped vacuum in the sampler with a built-in pressure measuring device.

(6) (i) Measure the vacuum in the sampler with the built-in pressure measuring device again at a later time at least 10 minutes after the first pressure measurement.

(ii) **Caution:** Following completion of the test, the adaptor valve should be opened slowly to limit the flow rate of air into the sampler. Excessive air flow rate may blow oil out of the impactor.

(7) Upon completion of the test, open the adaptor valve, remove the adaptor and plugs, and restore the sampler to the normal operating configuration.

(b) The associated leak test procedure shall require that for successful passage of this test, the difference between the two pressure measurements shall not be greater than the number of mm of Hg specified for the sampler by the manufacturer, based on the actual internal volume of the sampler, that indicates a leak of less than 80 mL/min.

(c) Variations of the suggested technique or an alternative external leak test technique may be required for samplers whose design or configuration would make the suggested technique impossible or impractical. The specific proposed external leak test procedure, or particularly an alternative leak test technique, proposed for a particular candidate sampler may be described and submitted to the EPA for specific individual acceptability either as part of a reference or equivalent method application under part 53 of this chapter or in writing in advance of such an intended application under part 53 of this chapter.

7.4.6.2 *Internal, filter bypass leakage.* The sampler shall include an internal, filter bypass leak-check capability consisting of components, accessory hardware, operator interface controls, a written procedure in the Operation/Instruction Manual, and all other necessary functional capability to permit and facilitate the sampler operator to conveniently carry out a test for internal filter bypass leakage in the sampler at a field monitoring site without additional equipment. The purpose of the test is to determine that any portion of the sample flow rate that leaks past the sample filter without passing through the filter is insignificant relative to the design flow rate for the sampler.

(a) The suggested technique for the operator to use for this leak test is as follows:

(1) Carry out an external leak test as provided under section 7.4.6.1 of this appendix which indicates successful passage of the prescribed external leak test.

(2) Install a flow-impervious membrane material in the filter cassette, either with or without a filter, as appropriate, which effectively prevents air flow through the filter.

(3) Use the sampler air pump to draw a partial vacuum in the sampler, downstream of the filter holder assembly, of at least 55 mm Hg (75 cm water column).

(4) Plug the flow system downstream of the filter holder to isolate the components under vacuum from the pump, such as with a built-in valve.

(5) Stop the pump.

(6) Measure the trapped vacuum in the sampler with a built-in pressure measuring device.

(7) Measure the vacuum in the sampler with the built-in pressure measuring device again at a later time at least 10 minutes after the first pressure measurement.

(8) Remove the flow plug and membrane and restore the sampler to the normal operating configuration.

(b) The associated leak test procedure shall require that for successful passage of this test, the difference between the two pressure measurements shall not be greater than the number of mm of Hg specified for the sampler by the manufacturer, based on the actual internal volume of the portion of the sampler under vacuum, that indicates a leak of less than 80 mL/min.

(c) Variations of the suggested technique or an alternative internal, filter bypass leak test technique may be required for samplers whose design or configuration would make the suggested technique impossible or impractical. The specific proposed internal leak test procedure, or particularly an alternative internal leak test technique proposed for a particular candidate sampler may be described and submitted to the EPA for specific individual acceptability either as part of a reference or equivalent method application under part 53 of this chapter or in writing in advance of such intended application under part 53 of this chapter.

7.4.7 *Range of operational conditions.* The sampler is required to operate properly and meet all requirements specified in this appendix over the following operational ranges.

7.4.7.1 *Ambient temperature.* -30 to +45 °C (Note: Although for practical reasons, the temperature range over which samplers are required to be tested under part 53 of this chapter is -20 to +40 °C, the sampler shall be designed to operate properly over this wider temperature range.).

7.4.7.2 *Ambient relative humidity.* 0 to 100 percent.

7.4.7.3 *Barometric pressure range.* 600 to 800 mm Hg.

7.4.8 *Ambient temperature sensor.* The sampler shall have capability to measure the temperature of the ambient air surrounding the sampler over the range of -30 to +45 °C, with a resolution of 0.1 °C and accuracy of ±2.0 °C, referenced as described in reference 3 in section 13.0 of this appendix, with and without maximum solar insolation.

7.4.8.1 The ambient temperature sensor shall be mounted external to the sampler enclosure and shall have a passive, naturally ventilated sun shield. The sensor shall be located such that the entire sun shield is at least 5 cm above the horizontal plane of the sampler case or enclosure (disregarding the inlet and downtube) and external to the vertical plane of the nearest side or protuberance of the sampler case or enclosure. The maximum temperature measurement error of the ambient temperature measurement system shall be less than 1.6 °C at 1 m/s wind speed and 1000 W/m2 solar radiation intensity.

7.4.8.2 The ambient temperature sensor shall be of such a design and mounted in such a way as to facilitate its convenient dismounting and immersion in a liquid for calibration and comparison to the filter temperature sensor, under section 7.4.11 of this appendix.

7.4.8.3 This ambient temperature measurement shall be updated at least every 30 seconds during both sampling and standby (non-sampling) modes of operation. A visual indication of the current (most recent) value of the ambient temperature measurement, updated at least every 30 seconds, shall be available to the sampler operator during both sampling and standby (non-sampling) modes of operation, as specified in Table L–1 of section 7.4.19 of this appendix.

7.4.8.4 This ambient temperature measurement shall be used for the purpose of monitoring filter temperature deviation from ambient temperature, as required by section 7.4.11 of this appendix, and may be used for purposes of effecting filter temperature control, under section 7.4.10 of this appendix, or computation of volumetric flow rate, under sections 7.4.1 to 7.4.5 of this appendix, if appropriate.

7.4.8.5 Following the end of each sample period, the sampler shall report the maximum, minimum, and average temperature for the sample period, as specified in Table L–1 of section 7.4.19 of this appendix.

7.4.9 *Ambient barometric sensor.* The sampler shall have capability to measure the barometric pressure of the air surrounding the sampler over a range of 600 to 800 mm Hg referenced as described in reference 3 in section 13.0 of this appendix; also see part 53, subpart E of this chapter. This barometric pressure measurement shall have a resolution of 5 mm Hg and an accuracy of ±10 mm Hg and shall be updated at least every 30 seconds. A visual indication of the value of the current (most recent) barometric pressure measurement, updated at least every 30 seconds, shall be available to the sampler operator during both sampling and standby (non-sampling) modes of operation, as specified in Table L–1 of section 7.4.19 of this appendix. This barometric pressure measurement may be used for purposes of computation of volumetric flow rate, under sections 7.4.1 to 7.4.5 of this appendix, if appropriate. Following the end of a sample period, the sampler shall report the maximum, minimum, and mean barometric pressures for the sample period, as specified in Table L–1 of section 7.4.19 of this appendix.

7.4.10 *Filter temperature control (sampling and post-sampling).* The sampler shall provide a means to limit the temperature rise of the sample filter (all sample filters for sequential samplers), from insolation and other sources, to no more 5 °C above the temperature of the ambient air surrounding the sampler, during both sampling and post-sampling periods of operation. The post-sampling period is the non-sampling period between the end of the active sampling period and the time of retrieval of the sample filter by the sampler operator.

7.4.11 *Filter temperature sensor(s).*

7.4.11.1 The sampler shall have the capability to monitor the temperature of the sample filter (all sample filters for sequential samplers) over the range of -30 to +45 °C during both sampling and non-sampling periods. While the exact location of this temperature sensor is not explicitly specified, the filter temperature measurement system must demonstrate agreement, within 1 °C, with a test temperature sensor located within 1 cm of the center of the filter downstream of the filter during both sampling and non-sampling modes, as specified in the filter temperature measurement test described in part 53, subpart E of this chapter. This filter temperature measurement shall have a resolution of 0.1 °C and accuracy of ±1.0 °C, referenced as described in reference 3 in section 13.0 of this appendix. This temperature sensor shall be of such a design and mounted in such a way as to facilitate its reasonably convenient dismounting and immersion in a liquid for calibration and comparison to the ambient temperature sensor under section 7.4.8 of this appendix.

7.4.11.2 The filter temperature measurement shall be updated at least every 30 seconds during both sampling and standby (non-sampling) modes of operation. A visual indication of the current (most recent) value of the filter temperature measurement, updated at least every 30 seconds, shall be available to the sampler operator during both sampling and standby (non-sampling) modes of operation, as specified in Table L–1 of section 7.4.19 of this appendix.

7.4.11.3 For sequential samplers, the temperature of each filter shall be measured individually unless it can be shown, as specified in the filter temperature measurement test described in § 53.57 of this chapter, that the temperature of each filter can be represented by fewer temperature sensors.

7.4.11.4 The sampler shall also provide a warning flag indicator following any occurrence in which the filter temperature (any filter temperature for sequential samplers) exceeds the ambient temperature by more than 5 °C for more than 30 consecutive minutes during either the sampling or post-sampling periods of operation, as specified in Table L–1 of section 7.4.19 of this appendix, under section 10.12 of this appendix, regarding sample validity when a warning flag occurs. It is further recommended (not required) that the sampler be capable of recording the maximum differential between the measured filter temperature and the ambient temperature and its time and date of occurrence during both sampling and post-sampling (non-sampling) modes of operation and providing for those data to be accessible to the sampler operator following the end of the sample period, as suggested in Table L–1 of section 7.4.19 of this appendix.

7.4.12 *Clock/timer system.*

(a) The sampler shall have a programmable real-time clock timing/control system that:

(1) Is capable of maintaining local time and date, including year, month, day-of-month, hour, minute, and second to an accuracy of ±1.0 minute per month.

(2) Provides a visual indication of the current system time, including year, month, day-of-month, hour, and minute, updated at least each minute, for operator verification.

(3) Provides appropriate operator controls for setting the correct local time and date.

(4) Is capable of starting the sample collection period and sample air flow at a specific, operator-settable time and date, and stopping the sample air flow and terminating the sampler collection period 24 hours (1440 minutes) later, or at a specific, operator-settable time and date.

(b) These start and stop times shall be readily settable by the sampler operator to within ±1.0 minute. The system shall provide a visual indication of the current start and stop time settings, readable to ±1.0 minute, for verification by the operator, and the start and stop times shall also be available via the data output port, as specified in Table L–1 of section 7.4.19 of this appendix. Upon execution of a programmed sample period start, the sampler shall automatically reset all sample period information and warning flag indications pertaining to a previous sample period. Refer also to section 7.4.15.4 of this appendix regarding retention of current date and time and programmed start and stop times during a temporary electrical power interruption.

7.4.13 *Sample time determination.* The sampler shall be capable of determining the elapsed sample collection time for each $PM_{2.5}$ sample, accurate to within ±1.0 minute, measured as the time between the start of the sampling period, under section 7.4.12 of this appendix and the termination of the sample period, under section 7.4.12 of this appendix or section 7.4.4 of this appendix. This elapsed sample time shall not include periods when the sampler is inoperative due to a temporary interruption of electrical power, under section 7.4.15.4 of this appendix. In the event that the elapsed sample time determined for the sample period is not within the range specified for the required sample period in section 3.3 of this appendix, the sampler shall set a warning flag indicator. The date and time of the start of the sample period, the value of the elapsed sample time for the sample period, and the flag indicator status shall be available to the sampler operator following the end of the sample period, as specified in Table L–1 of section 7.4.19 of this appendix.

7.4.14 *Outdoor environmental enclosure.* The sampler shall have an outdoor enclosure (or enclosures) suitable to protect the filter and other non-weatherproof components of the sampler from precipitation, wind, dust, extremes of temperature and humidity; to help maintain temperature control of the

filter (or filters, for sequential samplers); and to provide reasonable security for sampler components and settings.

7.4.15 *Electrical power supply.*

7.4.15.1 The sampler shall be operable and function as specified herein when operated on an electrical power supply voltage of 105 to 125 volts AC (RMS) at a frequency of 59 to 61 Hz. Optional operation as specified at additional power supply voltages and/or frequencies shall not be precluded by this requirement.

7.4.15.2 The design and construction of the sampler shall comply with all applicable National Electrical Code and Underwriters Laboratories electrical safety requirements.

7.4.15.3 The design of all electrical and electronic controls shall be such as to provide reasonable resistance to interference or malfunction from ordinary or typical levels of stray electromagnetic fields (EMF) as may be found at various monitoring sites and from typical levels of electrical transients or electronic noise as may often or occasionally be present on various electrical power lines.

7.4.15.4 In the event of temporary loss of electrical supply power to the sampler, the sampler shall not be required to sample or provide other specified functions during such loss of power, except that the internal clock/timer system shall maintain its local time and date setting within ±1 minute per week, and the sampler shall retain all other time and programmable settings and all data required to be available to the sampler operator following each sample period for at least 7 days without electrical supply power. When electrical power is absent at the operator-set time for starting a sample period or is interrupted during a sample period, the sampler shall automatically start or resume sampling when electrical power is restored, if such restoration of power occurs before the operator-set stop time for the sample period.

7.4.15.5 The sampler shall have the capability to record and retain a record of the year, month, day-of-month, hour, and minute of the start of each power interruption of more than 1 minute duration, up to 10 such power interruptions per sample period. (More than 10 such power interruptions shall invalidate the sample, except where an exceedance is measured, under section 3.3 of this appendix.) The sampler shall provide for these power interruption data to be available to the sampler operator following the end of the sample period, as specified in Table L–1 of section 7.4.19 of this appendix.

7.4.16 *Control devices and operator interface.* The sampler shall have mechanical, electrical, or electronic controls, control devices, electrical or electronic circuits as necessary to provide the timing, flow rate measurement and control, temperature control, data storage and computation, operator interface, and other functions specified. Operator-accessible controls, data displays, and interface devices shall be designed to be simple, straightforward, reliable, and easy to learn, read, and operate under field conditions. The sampler shall have provision for operator input and storage of up to 64 characters of numeric (or alphanumeric) data for purposes of site, sampler, and sample identification. This information shall be available to the sampler operator for verification and change and for output via the data output port along with other data following the end of a sample period, as specified in Table L–1 of section 7.4.19 of this appendix. All data required to be available to the operator following a sample collection period or obtained during standby mode in a post-sampling period shall be retained by the sampler until reset, either manually by the operator or automatically by the sampler upon initiation of a new sample collection period.

7.4.17 *Data output port requirement.* The sampler shall have a standard RS–232C data output connection through which digital data may be exported to an external data storage or transmission device. All information which is required to be available at the end of each sample period shall be accessible through this data output connection. The information that shall be accessible though this output port is summarized in Table L–1 of section 7.4.19 of this appendix. Since no specific format for the output data is provided, the sampler manufacturer or vendor shall make available to sampler purchasers appropriate computer software capable of receiving exported sampler data and correctly translating the data into a standard spreadsheet format and optionally any other formats as may be useful to sampler users. This requirement shall not preclude the sampler from offering other types of output connections in addition to the required RS–232C port.

7.4.18 *Operation/instruction manual.* The sampler shall include an associated comprehensive operation or instruction manual, as required by part 53 of this chapter, which includes detailed operating instructions on the setup, operation, calibration, and maintenance of the sampler. This manual shall provide complete and detailed descriptions of the operational and calibration procedures prescribed for field use of the sampler and all instruments utilized as part of this reference method. The manual shall include adequate warning of potential safety hazards that may result from normal use or malfunction of the method and a description of necessary safety precautions. The manual shall also include a clear description of all procedures pertaining to installation, operation, periodic and corrective maintenance, and troubleshooting, and shall include parts identification diagrams.

7.4.19 *Data reporting requirements.* The various information that the sampler is required to provide and how it is to be provided is summarized in the following Table L–1.

TABLE L–1.—SUMMARY OF INFORMATION TO BE PROVIDED BY THE SAMPLER

Information to be provided	Appendix L section reference	Availability				Format	
		Anytime[1]	End of period[2]	Visual display[3]	Data output[4]	Digital reading[5]	Units
Flow rate, 30-second maximum interval.	7.4.5.1	✔	.....	✔	*	XX.X	L/min
Flow rate, average for the sample period.	7.4.5.2	*	✔	*	✔	XX.X	L/min
Flow rate, CV, for sample period.	7.4.5.2	*	✔	*	✔■	XX.X	%
Flow rate, 5-min. average out of spec. (FLAG[6]).	7.4.5.2	✔	✔	✔	✔■	On/Off	
Sample volume, total ..	7.4.5.2	*	✔	✔	✔■	XX.X	m^3
Temperature, ambient, 30-second interval.	7.4.8	✔	.....	✔	.....	XX.X	°C
Temperature, ambient, min., max., average for the sample period.	7.4.8	*	✔	✔	✔■	XX.X	°C
Baro pressure, ambient, 30-second interval.	7.4.9	✔	.....	✔	.....	XXX	mm Hg

TABLE L–1.—SUMMARY OF INFORMATION TO BE PROVIDED BY THE SAMPLER—Continued

Information to be provided	Appendix L section reference	Availability				Format	
		Anytime[1]	End of period[2]	Visual display[3]	Data output[4]	Digital reading[5]	Units
Baro pressure, ambient, min., max., average for the sample period.	7.4.9	*	✔	✔	✔■	XXX	mm Hg
Filter temperature, 30-second interval.	7.4.11	✔	.....	✔	.....	XX.X	°C
Filter temperature differential, 30-second interval, out of spec. (FLAG[6]).	7.4.11	*	✔	✔	✔■	On/Off	
Filter temperature, maximum differential from ambient, date, time of occurrence.	7.4.11	*	*	*	*	X.X, YY/MM/DD HH:mm.	°C, Yr./Mon./Day Hrs. min
Date and time	7.4.12	✔	.....	✔	.....	YY/MM/DD HH:mm	Yr./Mon./Day Hrs. min
Sample start and stop time settings.	7.4.12	✔	✔	✔	✔	YY/MM/DD HH:mm	Yr./Mon./Day Hrs. min
Sample period start time.	7.4.12	.....	✔	✔	✔■	YYYY/MM/DD HH:mm	Yr./Mon./Day Hrs. min
Elapsed sample time ..	7.4.13	*	✔	✔	✔■	HH:mm	Hrs. min
Elapsed sample time, out of spec. (FLAG[6]).	7.4.13	.....	✔	✔	✔■	On/Off	
Power interruptions >1 min., start time of first 10.	7.4.15.5 ..	*	✔	*	✔	1HH:mm, 2HH:mm, etc	Hrs. min
User-entered information, such as sampler and site identification.	7.4.16	✔	✔	✔	✔■	As entered	

✔ Provision of this information is required.

Provision of this information is optional. If information related to the entire sample period is optionally provided prior to the end of the sample period, the value provided should be the value calculated for the portion of the sampler period completed up to the time the information is provided.

■ Indicates that this information is also required to be provided to the AIRS data bank; see §§58.26 and 58.35 of this chapter.

[1] Information is required to be available to the operator at any time the sampler is operating, whether sampling or not.

[2] Information relates to the entire sampler period and must be provided following the end of the sample period until reset manually by the operator or automatically by the sampler upon the start of a new sample period.

[3] Information shall be available to the operator visually.

[4] Information is to be available as digital data at the sampler's data output port specified in section 7.4.16 of this appendix following the end of the sample period until reset manually by the operator or automatically by the sampler upon the start of a new sample period.

[5] Digital readings, both visual and data output, shall have not less than the number of significant digits and resolution specified.

[6] Flag warnings may be displayed to the operator by a single-flag indicator or each flag may be displayed individually. Only a set (on) flag warning must be indicated; an off (unset) flag may be indicated by the absence of a flag warning. Sampler users should refer to section 10.12 of this appendix regarding the validity of samples for which the sampler provided an associated flag warning.

8.0 *Filter Weighing.* See reference 2 in section 13.0 of this appendix, for additional, more detailed guidance.

8.1 *Analytical balance.* The analytical balance used to weigh filters must be suitable for weighing the type and size of filters specified, under section 6.0 of this appendix, and have a readability of ±1 µg. The balance shall be calibrated as specified by the manufacturer at installation and recalibrated immediately prior to each weighing session. See reference 2 in section 13.0 of this appendix for additional guidance.

8.2 *Filter conditioning.* All sample filters used shall be conditioned immediately before both the pre- and post-sampling weighings as specified below. See reference 2 in section 13.0 of this appendix for additional guidance.

8.2.1 *Mean temperature.* 20 - 23 °C.

8.2.2 *Temperature control.* ±2 °C over 24 hours.

8.2.3 *Mean humidity.* Generally, 30–40 percent relative humidity; however, where it can be shown that the mean ambient relative humidity during sampling is less than 30 percent, conditioning is permissible at a mean relative humidity within ±5 relative humidity percent of the mean ambient relative humidity during sampling, but not less than 20 percent.

8.2.4 *Humidity control.* ±5 relative humidity percent over 24 hours.

8.2.5 *Conditioning time.* Not less than 24 hours.

8.3 *Weighing procedure.*

8.3.1 New filters should be placed in the conditioning environment immediately upon arrival and stored there until the pre-sampling weighing. See reference 2 in section 13.0 of this appendix for additional guidance.

8.3.2 The analytical balance shall be located in the same controlled environment in which the filters are conditioned. The filters shall be weighed immediately following the conditioning period without intermediate or transient exposure to other conditions or environments.

8.3.3 Filters must be conditioned at the same conditions (humidity within ±5 relative humidity percent) before both the pre- and post-sampling weighings.

8.3.4 Both the pre- and post-sampling weighings should be carried out on the same analytical balance, using an effective technique to neutralize static charges on the filter, under reference 2 in section 13.0 of this appendix. If possible, both weighings should be carried out by the same analyst.

8.3.5 The pre-sampling (tare) weighing shall be within 30 days of the sampling period.

8.3.6 The post-sampling conditioning and weighing shall be completed within 240 hours (10 days) after the end of the sample period, unless the filter sample is maintained at 4 °C or less during the entire time between retrieval from the sampler and the start of the conditioning, in which case the period shall

not exceed 30 days. Reference 2 in section 13.0 of this appendix has additional guidance on transport of cooled filters.

8.3.7 Filter blanks.

8.3.7.1 New field blank filters shall be weighed along with the pre-sampling (tare) weighing of each lot of $PM_{2.5}$ filters. These blank filters shall be transported to the sampling site, installed in the sampler, retrieved from the sampler without sampling, and reweighed as a quality control check.

8.3.7.2 New laboratory blank filters shall be weighed along with the pre-sampling (tare) weighing of each set of $PM_{2.5}$ filters. These laboratory blank filters should remain in the laboratory in protective containers during the field sampling and should be reweighed as a quality control check.

8.3.8 Additional guidance for proper filter weighing and related quality assurance activities is provided in reference 2 in section 13.0 of this appendix.

9.0 *Calibration*. Reference 2 in section 13.0 of this appendix contains additional guidance.

9.1 *General requirements.*

9.1.1 Multipoint calibration and single-point verification of the sampler's flow rate measurement device must be performed periodically to establish and maintain traceability of subsequent flow measurements to a flow rate standard.

9.1.2 An authoritative flow rate standard shall be used for calibrating or verifying the sampler's flow rate measurement device with an accuracy of ±2 percent. The flow rate standard shall be a separate, stand-alone device designed to connect to the flow rate measurement adapter, Figure L–30 of this appendix. This flow rate standard must have its own certification and be traceable to a National Institute of Standards and Technology (NIST) primary standard for volume or flow rate. If adjustments to the sampler's flow rate measurement system calibration are to be made in conjunction with an audit of the sampler's flow measurement system, such adjustments shall be made following the audit. Reference 2 in section 13.0 of this appendix contains additional guidance.

9.1.3 The sampler's flow rate measurement device shall be re-calibrated after electromechanical maintenance or transport of the sampler.

9.2 *Flow rate calibration/verification procedure.*

9.2.1 $PM_{2.5}$ samplers may employ various types of flow control and flow measurement devices. The specific procedure used for calibration or verification of the flow rate measurement device will vary depending on the type of flow rate controller and flow rate measurement employed. Calibration shall be in terms of actual ambient volumetric flow rates (Q^a), measured at the sampler's inlet downtube. The generic procedure given here serves to illustrate the general steps involved in the calibration of a $PM_{2.5}$ sampler. The sampler operation/instruction manual required under section 7.4.18 of this appendix and the Quality Assurance Handbook in reference 2 in section 13.0 of this appendix provide more specific and detailed guidance for calibration.

9.2.2 The flow rate standard used for flow rate calibration shall have its own certification and be traceable to a NIST primary standard for volume or flow rate. A calibration relationship for the flow rate standard, e.g., an equation, curve, or family of curves relating actual flow rate (Q_a) to the flow rate indicator reading, shall be established that is accurate to within 2 percent over the expected range of ambient temperatures and pressures at which the flow rate standard may be used. The flow rate standard must be re-calibrated or re-verified at least annually.

9.2.3 The sampler flow rate measurement device shall be calibrated or verified by removing the sampler inlet and connecting the flow rate standard to the sampler's downtube in accordance with the operation/instruction manual, such that the flow rate standard accurately measures the sampler's flow rate. The sampler operator shall first carry out a sampler leak check and confirm that the sampler passes the leak test and then verify that no leaks exist between the flow rate standard and the sampler.

9.2.4 The calibration relationship between the flow rate (in actual L/min) indicated by the flow rate standard and by the sampler's flow rate measurement device shall be established or verified in accordance with the sampler operation/instruction manual. Temperature and pressure corrections to the flow rate indicated by the flow rate standard may be required for certain types of flow rate standards. Calibration of the sampler's flow rate measurement device shall consist of at least three separate flow rate measurements (multipoint calibration) evenly spaced within the range of -10 percent to +10 percent of the sampler's operational flow rate, section 7.4.1 of this appendix. Verification of the sampler's flow rate shall consist of one flow rate measurement at the sampler's operational flow rate. The sampler operation/instruction manual and reference 2 in section 13.0 of this appendix provide additional guidance.

9.2.5 If during a flow rate verification the reading of the sampler's flow rate indicator or measurement device differs by ±2 percent or more from the flow rate measured by the flow rate standard, a new multipoint calibration shall be performed and the flow rate verification must then be repeated.

9.2.6 Following the calibration or verification, the flow rate standard shall be removed from the sampler and the sampler inlet shall be reinstalled. Then the sampler's normal operating flow rate (in L/min) shall be determined with a clean filter in place. If the flow rate indicated by the sampler differs by ±2 percent or more from the required sampler flow rate, the sampler flow rate must be adjusted to the required flow rate, under section 7.4.1 of this appendix.

9.3 Periodic calibration or verification of the calibration of the sampler's ambient temperature, filter temperature, and barometric pressure measurement systems is also required. Reference 3 of section 13.0 of this appendix contains additional guidance.

10.0 *$PM_{2.5}$ Measurement Procedure* The detailed procedure for obtaining valid $PM_{2.5}$ measurements with each specific sampler designated as part of a reference method for $PM_{2.5}$ under part 53 of this chapter shall be provided in the sampler-specific operation or instruction manual required by section 7.4.18 of this appendix. Supplemental guidance is provided in section 2.12 of the Quality Assurance Handbook listed in reference 2 in section 13.0 of this appendix. The generic procedure given here serves to illustrate the general steps involved in the $PM_{2.5}$ sample collection and measurement, using a $PM_{2.5}$ reference method sampler.

10.1 The sampler shall be set up, calibrated, and operated in accordance with the specific, detailed guidance provided in the specific sampler's operation or instruction manual and in accordance with a specific quality assurance program developed and established by the user, based on applicable supplementary guidance provided in reference 2 in section 13.0 of this appendix.

10.2 Each new sample filter shall be inspected for correct type and size and for pinholes, particles, and other imperfections. Unacceptable filters should be discarded. A unique identification number shall be assigned to each filter, and an information record shall be established for each filter. If the filter identification number is not or cannot be marked directly on the filter, alternative means, such as a number-identified storage container, must be established to maintain positive filter identification.

10.3 Each filter shall be conditioned in the conditioning environment in accordance with the requirements specified in section 8.2 of this appendix.

10.4 Following conditioning, each filter shall be weighed in accordance with the requirements specified in section 8.0 of this appendix and the presampling weight recorded with the filter identification number.

10.5 A numbered and preweighed filter shall be installed in the sampler following the instructions provided in the sampler operation or instruction manual.

10.6 The sampler shall be checked and prepared for sample collection in accordance with instructions provided in the sampler operation or instruction manual and with the specific quality assurance program established for the sampler by the user.

10.7 The sampler's timer shall be set to start the sample collection at the beginning of the desired sample period and stop the sample collection 24 hours later.

10.8 Information related to the sample collection (site location or identification number, sample date, filter identification number, and sampler model and serial number) shall be recorded and, if appropriate, entered into the sampler.

10.9 The sampler shall be allowed to collect the $PM_{2.5}$ sample during the set 24-hour time period.

10.10 Within 96 hours of the end of the sample collection period, the filter, while still contained in the filter cassette, shall be carefully removed from the sampler, following the procedure provided in the sampler operation or instruction manual and the quality assurance program, and placed in a protective container. This protective container shall be made of metal and contain no loose material that could be transferred to the filter. The protective container shall hold

the filter cassette securely such that the cover shall not come in contact with the filter's surfaces. Reference 2 in section 13.0 of this appendix contains additional information.

10.11 The total sample volume in actual m^3 for the sampling period and the elapsed sample time shall be obtained from the sampler and recorded in accordance with the instructions provided in the sampler operation or instruction manual. All sampler warning flag indications and other information required by the local quality assurance program shall also be recorded.

10.12 All factors related to the validity or representativeness of the sample, such as sampler tampering or malfunctions, unusual meteorological conditions, construction activity, fires or dust storms, etc. shall be recorded as required by the local quality assurance program. The occurrence of a flag warning during a sample period shall not necessarily indicate an invalid sample but rather shall indicate the need for specific review of the QC data by a quality assurance officer to determine sample validity.

10.13 After retrieval from the sampler, the exposed filter containing the $PM_{2.5}$ sample should be transported to the filter conditioning environment as soon as possible ideally to arrive at the conditioning environment within 24 hours for conditioning and subsequent weighing. During the period between filter retrieval from the sampler and the start of the conditioning, the filter shall be maintained as cool as practical and continuously protected from exposure to temperatures over 25 °C. See section 8.3.6 of this appendix regarding time limits for completing the post-sampling weighing. See reference 2 in section 13.0 of this appendix for additional guidance on transporting filter samplers to the conditioning and weighing laboratory.

10.14. The exposed filter containing the $PM_{2.5}$ sample shall be re-conditioned in the conditioning environment in accordance with the requirements specified in section 8.2 of this appendix.

10.15. The filter shall be reweighed immediately after conditioning in accordance with the requirements specified in section 8.0 of this appendix, and the postsampling weight shall be recorded with the filter identification number.

10.16 The $PM_{2.5}$ concentration shall be calculated as specified in section 12.0 of this appendix.

11.0 *Sampler Maintenance*

The sampler shall be maintained as described by the sampler's manufacturer in the sampler-specific operation or instruction manual required under section 7.4.18 of this appendix and in accordance with the specific quality assurance program developed and established by the user based on applicable supplementary guidance provided in reference 2 in section 13.0 of this appendix.

12.0 *Calculations*

12.1 (a) The $PM_{2.5}$ concentration is calculated as:

$$PM_{2.5} = (W_f - W_i)/V_a$$

where:

$PM_{2.5}$ = mass concentration of $PM_{2.5}$, $\mu g/m^3$;

W_f, W_i = final and initial weights, respectively, of the filter used to collect the $PM_{2.5}$ particle sample, μg;

V_a = total air volume sampled in actual volume units, as provided by the sampler, m^3.

(b) Note: Total sample time must be between 1,380 and 1,500 minutes (23 and 25 hrs) for a fully valid $PM_{2.5}$ sample; however, see also section 3.3 of this appendix.

13.0 *References.*

1. Quality Assurance Handbook for Air Pollution Measurement Systems, Volume I, Principles. EPA/600/R–94/038a, April 1994. Available from CERI, ORD Publications, U.S. Environmental Protection Agency, 26 West Martin Luther King Drive, Cincinnati, Ohio 45268.

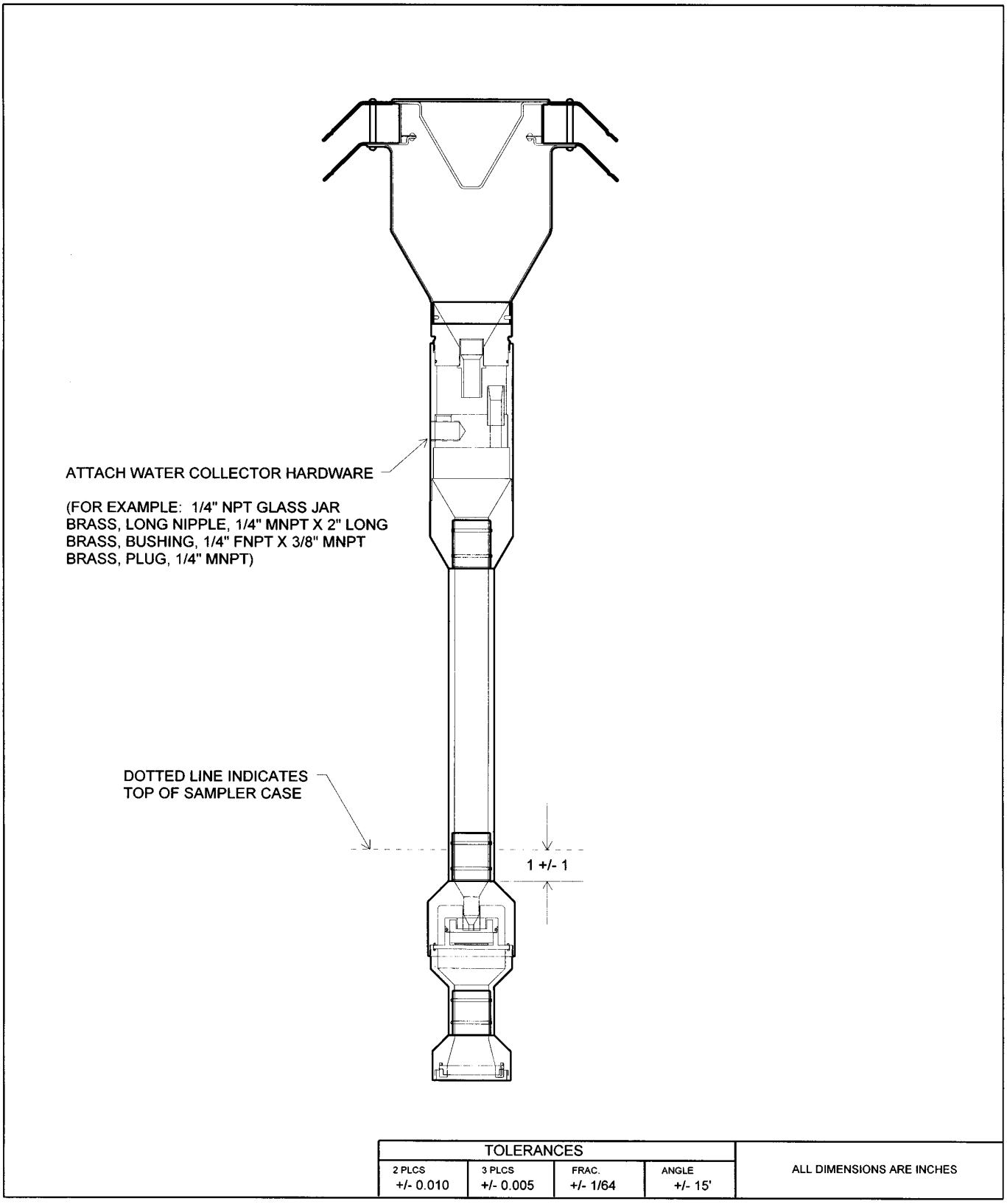
2. Copies of section 2.12 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II, Ambient Air Specific Methods, EPA/600/R–94/038b, are available from Department E (MD-77B), U.S. EPA, Research Triangle Park, NC 27711.

3. Quality Assurance Handbook for Air Pollution Measurement Systems, Volume IV: Meteorological Measurements, (Revised Edition) EPA/600/R–94/038d, March, 1995. Available from CERI, ORD Publications, U.S. Environmental Protection Agency, 26 West Martin Luther King Drive, Cincinnati, Ohio 45268.

4. Military standard specification (mil. spec.) 8625F, Type II, Class 1 as listed in Department of Defense Index of Specifications and Standards (DODISS), available from DODSSP–Customer Service, Standardization Documents Order Desk, 700 Robbins Avenue, Building 4D, Philadelphia, PA 1911–5094.

14.0 *Figures L–1 through L–30 to Appendix L.*

FIGURE L-1. PM2.5 SAMPLER, ASSEMBLY



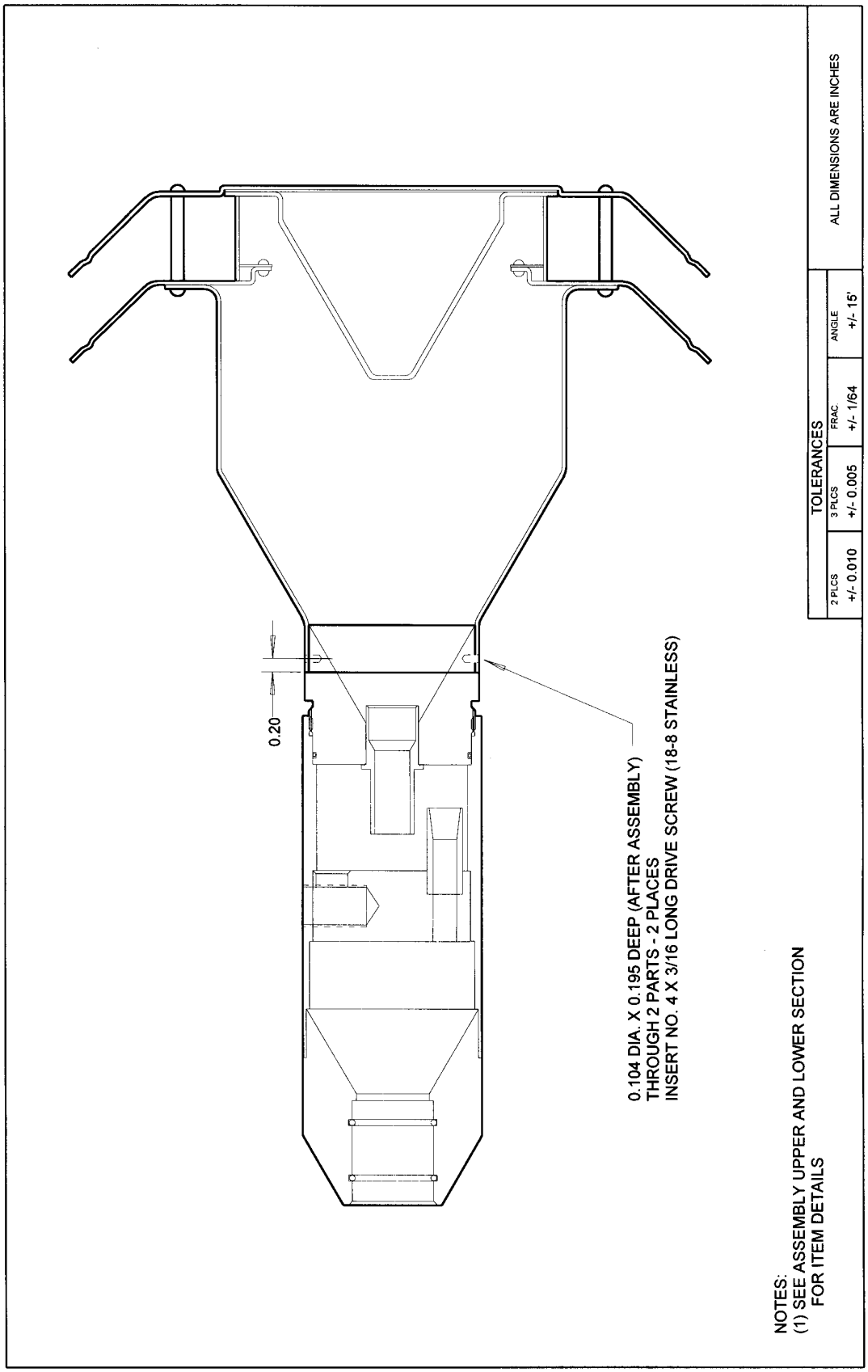


FIGURE L-2. 10-MICRON INLET, ASSEMBLY

FIGURE L-3. 10-MICRON ASSEMBLY, UPPER SECTION

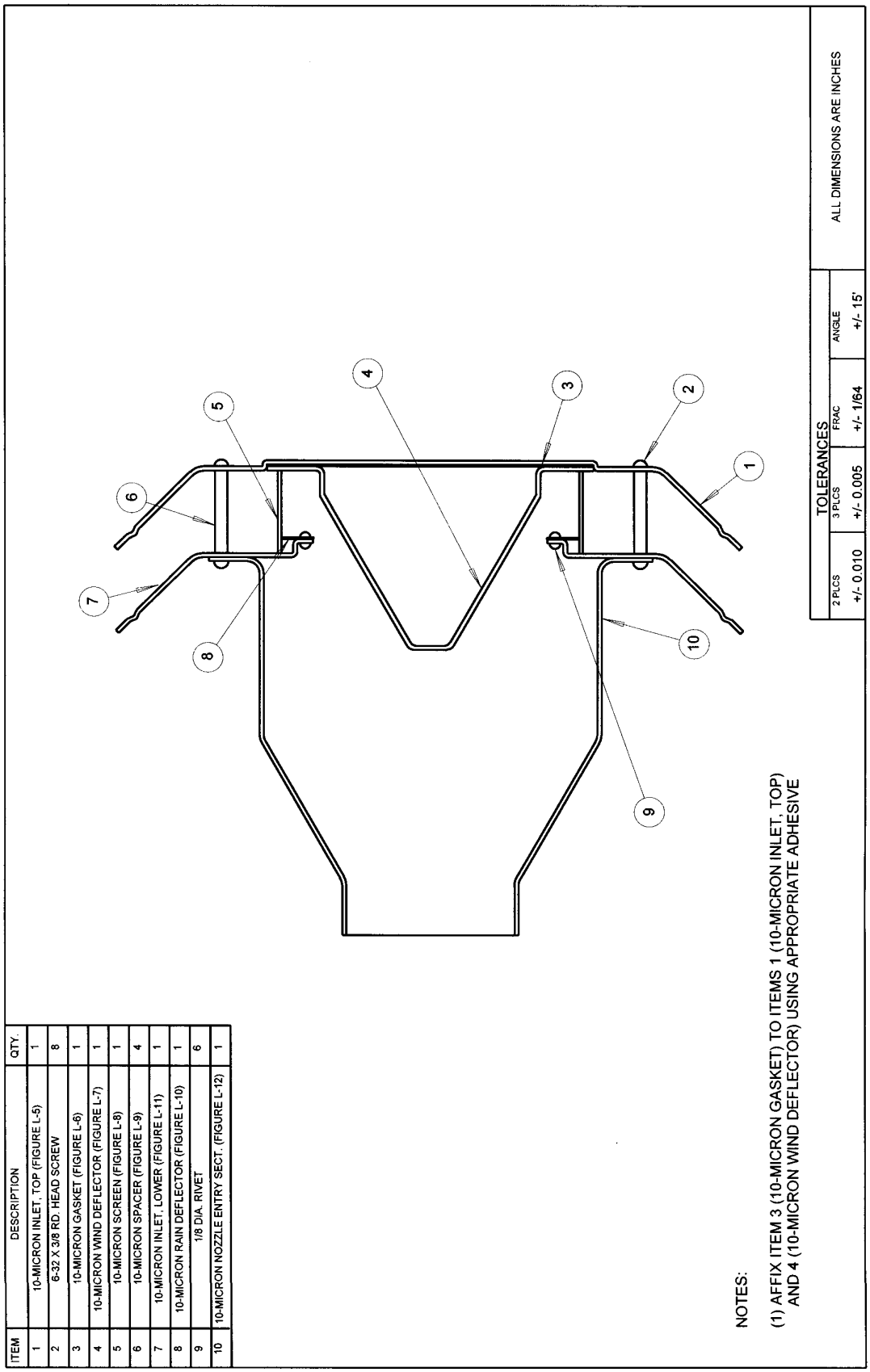


FIGURE L-4. 10-MICRON ASSEMBLY, LOWER SECTION

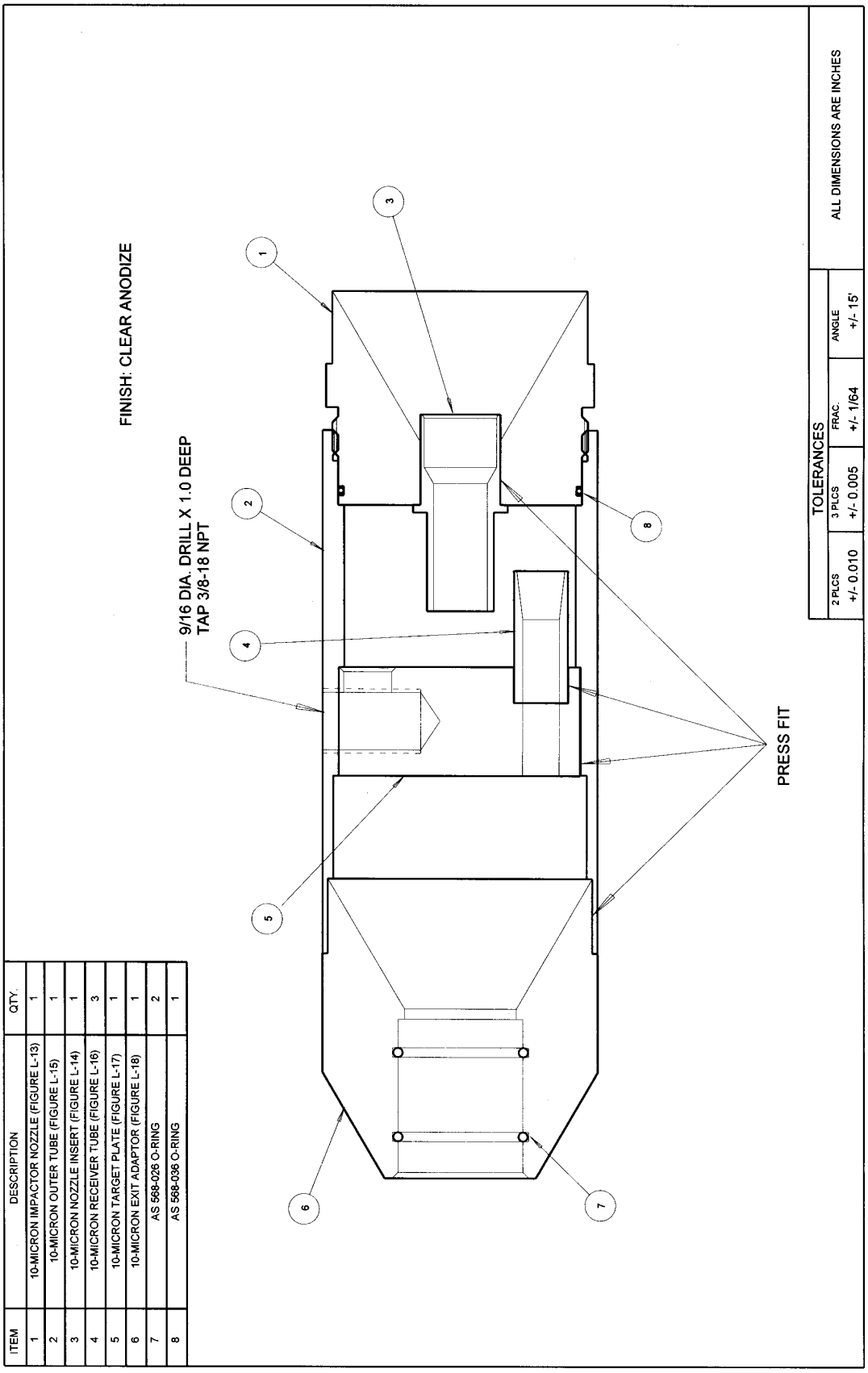
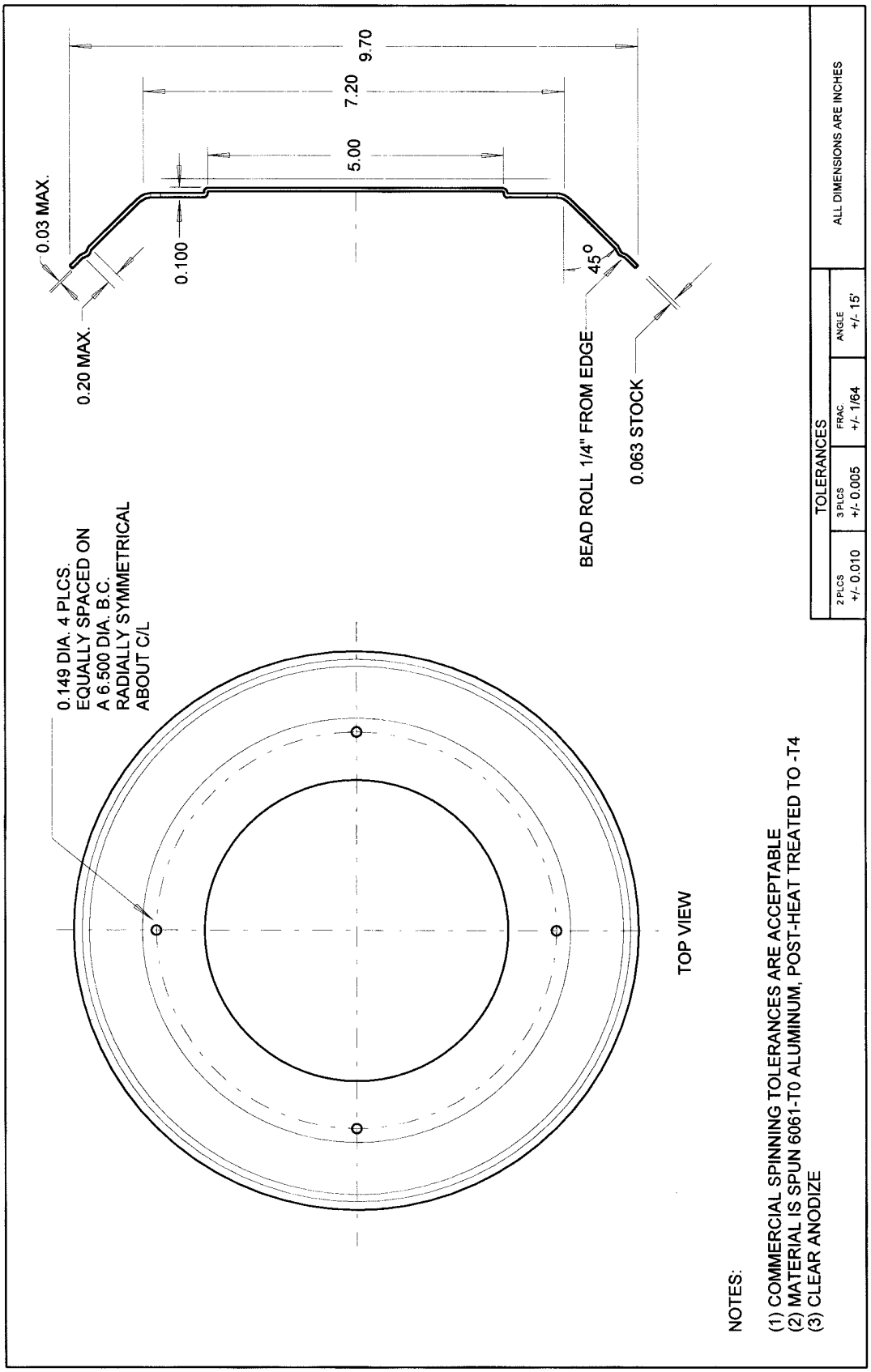


FIGURE L-5. 10-MICRON INLET, TOP



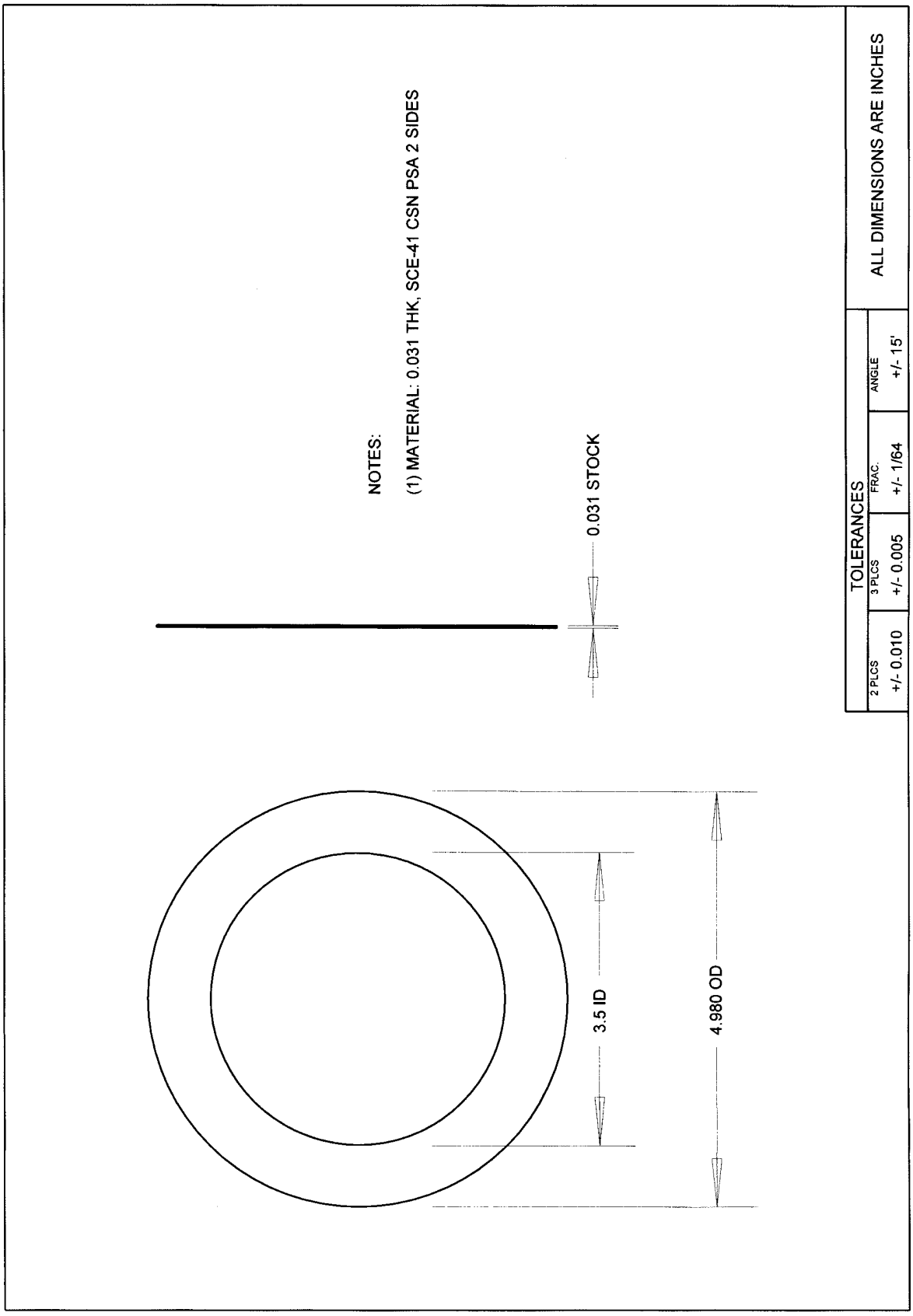
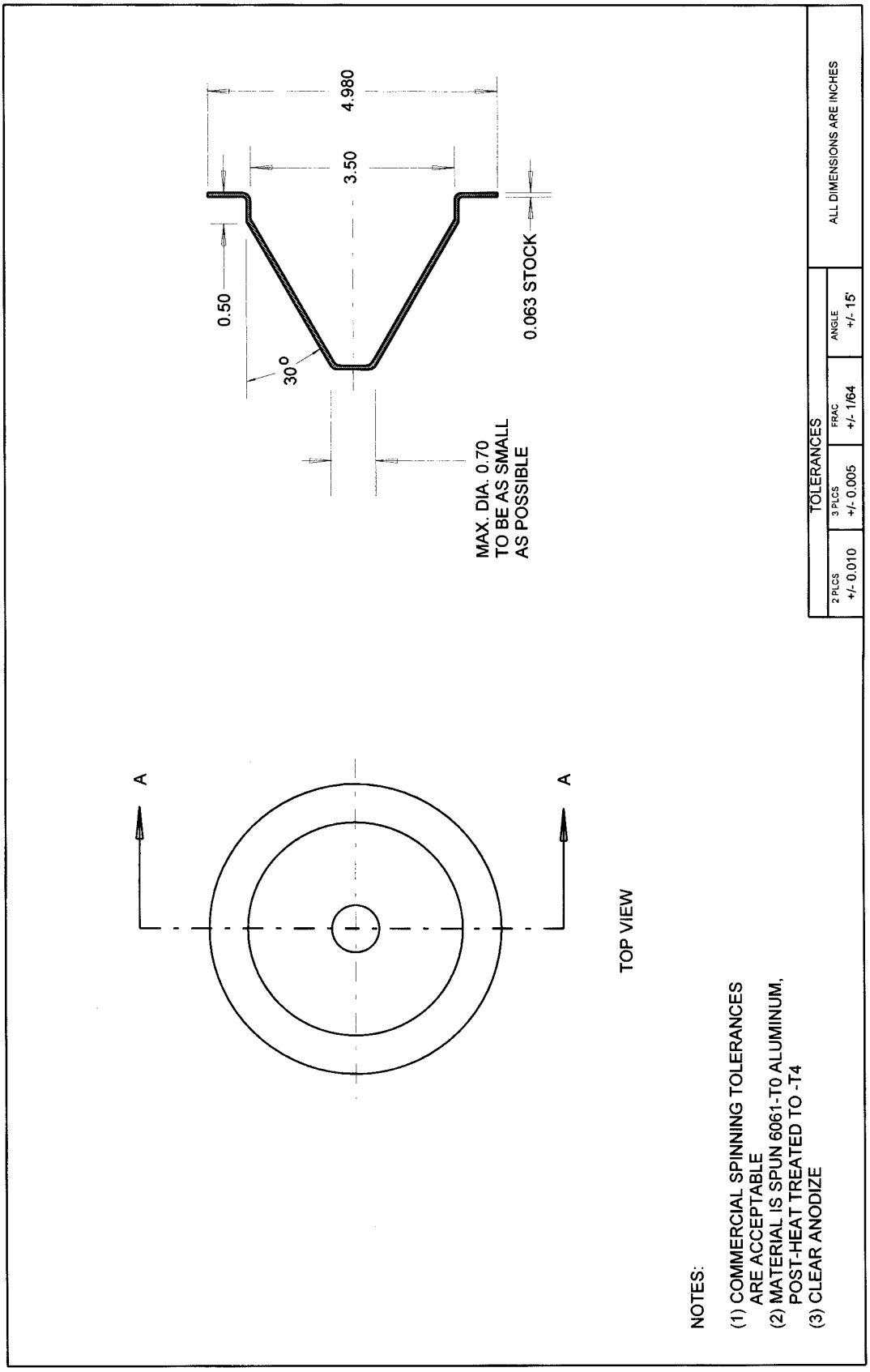


FIGURE L-6. 10-MICRON GASKET

FIGURE L-7. 10-MICRON WIND DEFLECTOR



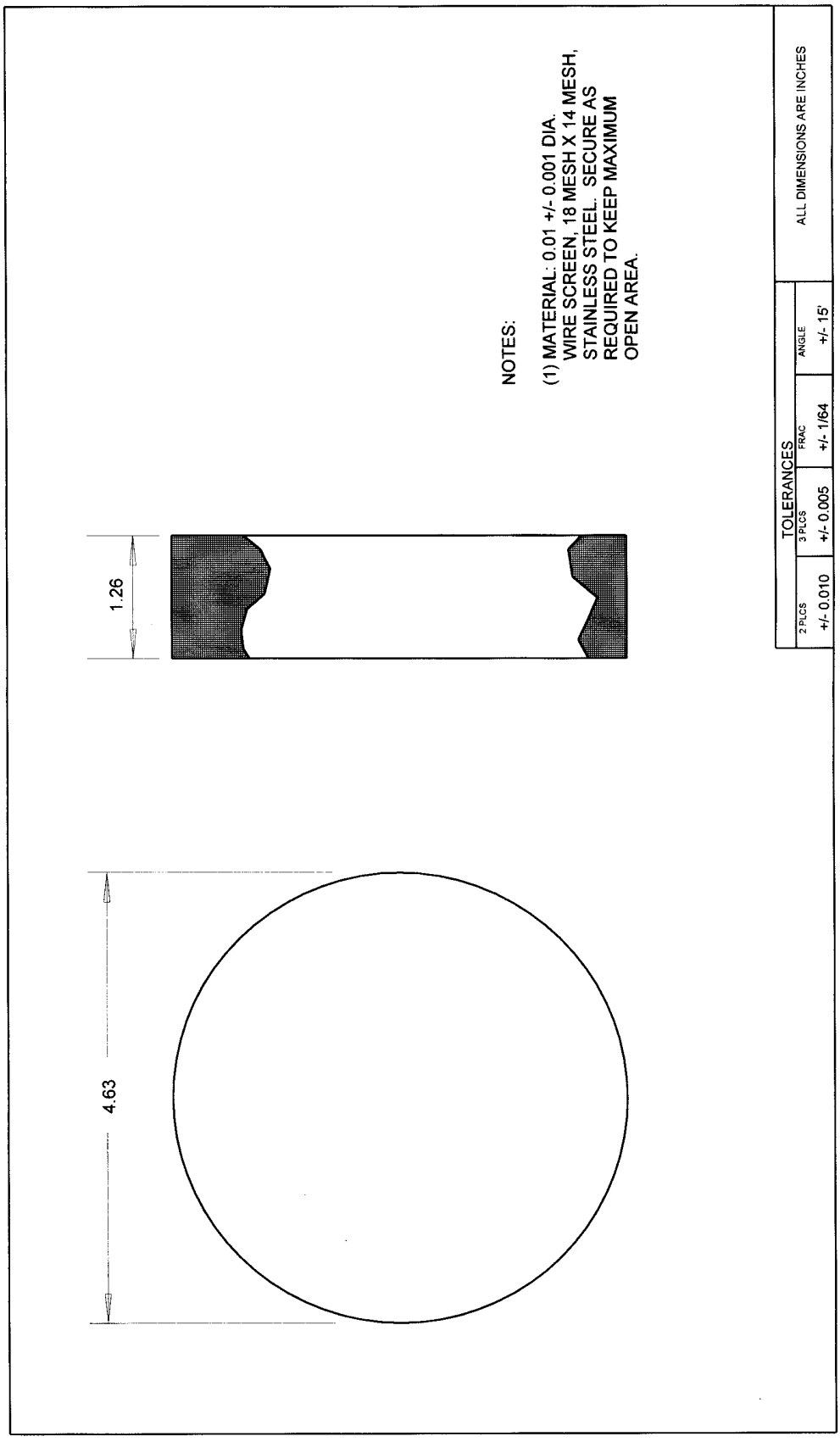


FIGURE L-8. 10-MICRON SCREEN

FIGURE L-9. 10-MICRON SPACER

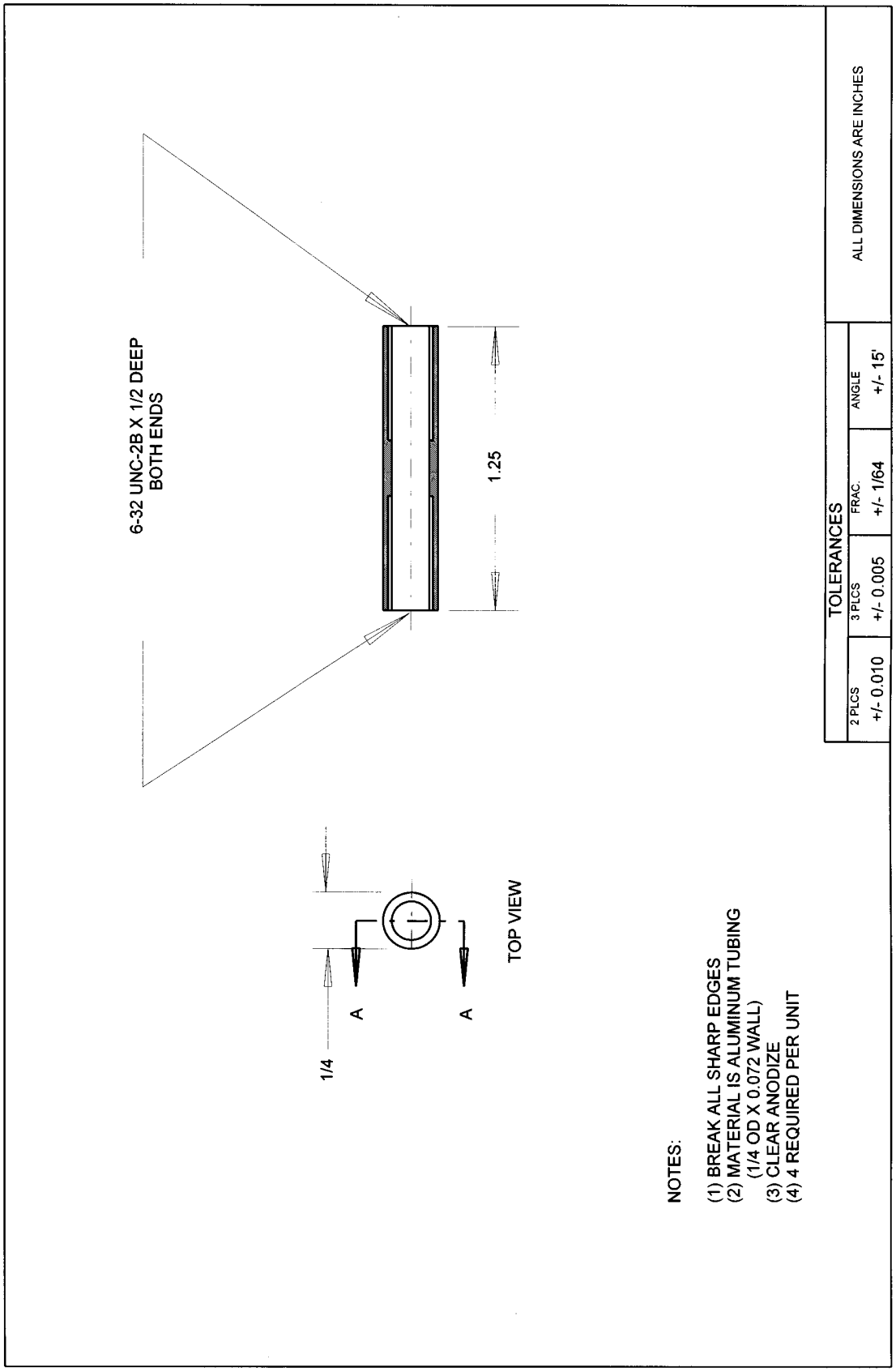
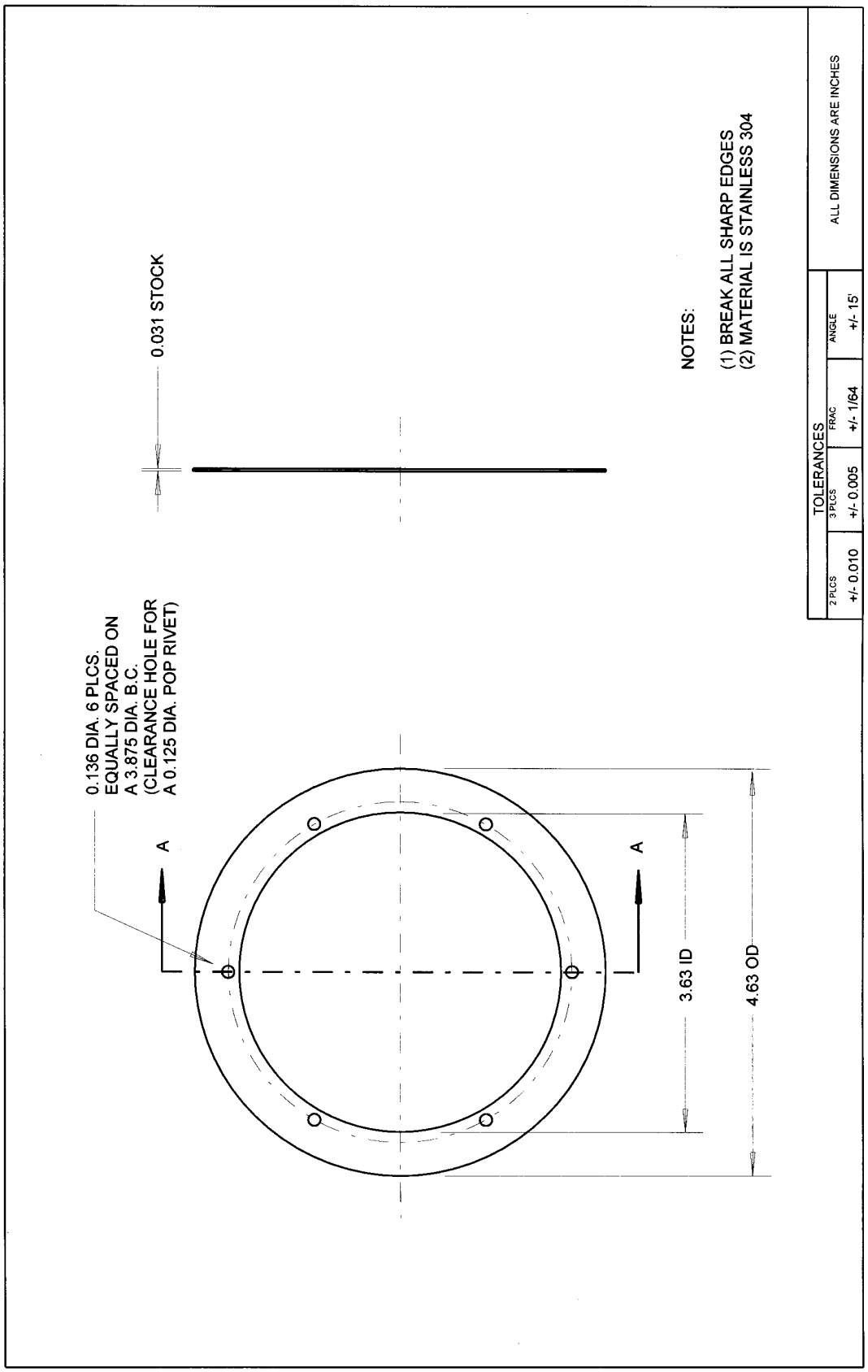


FIGURE L-10. 10-MICRON RAIN DEFLECTOR



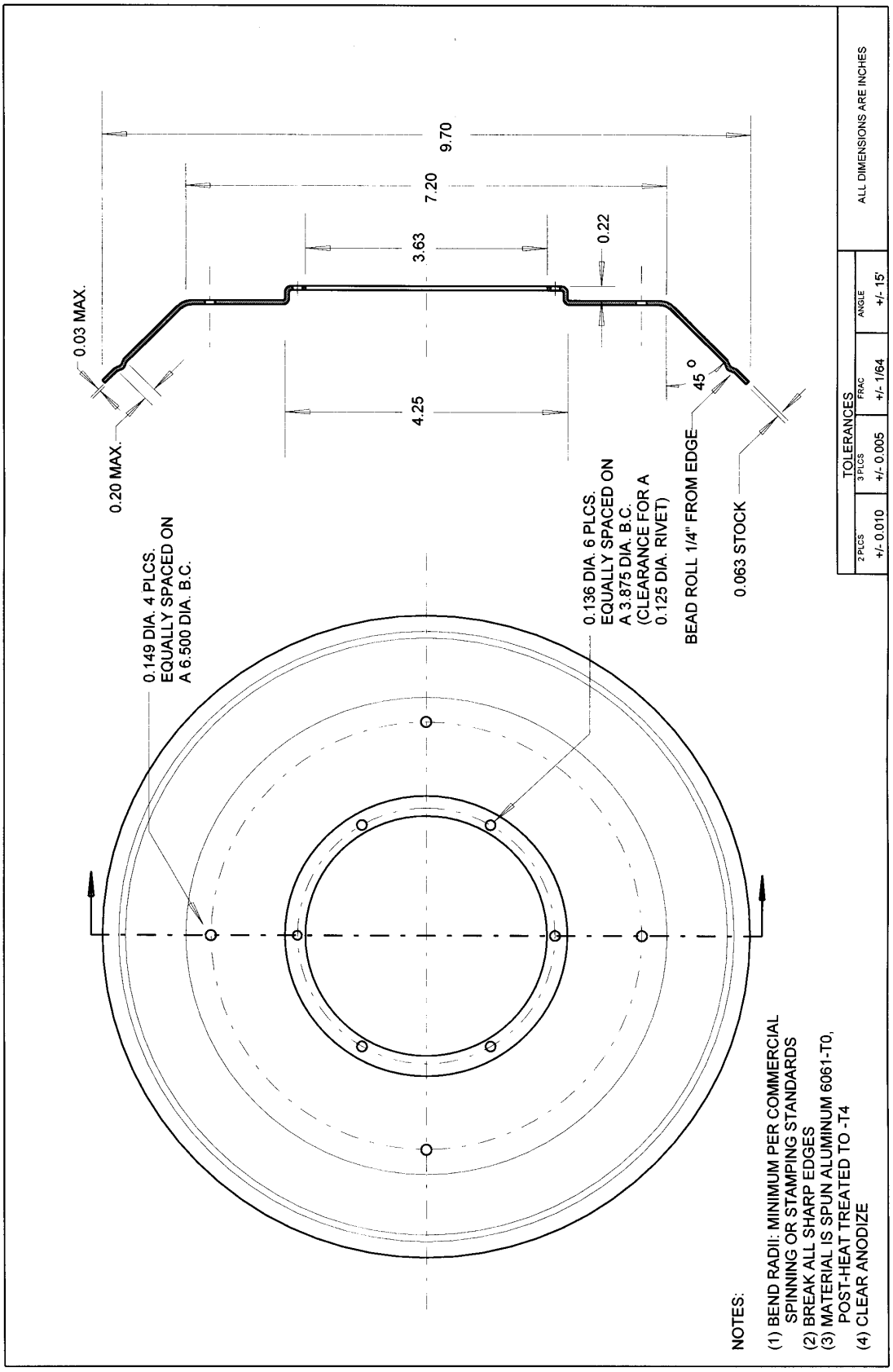


FIGURE L-11. 10-MICRON INLET, LOWER

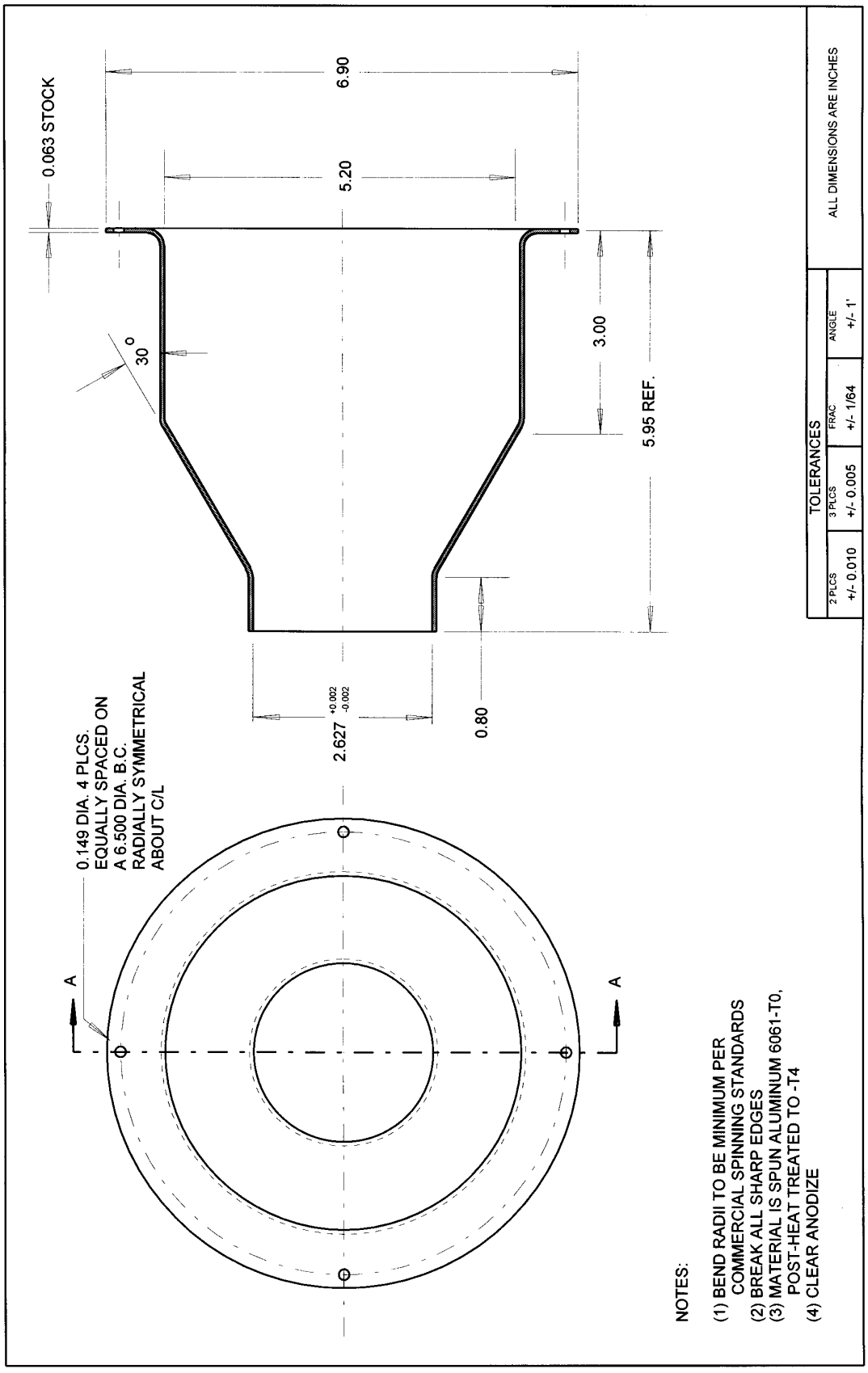


FIGURE L-12. 10-MICRON NOZZLE ENTRY SECTION

FIGURE L-13. 10-MICRON IMPACTOR NOZZLE

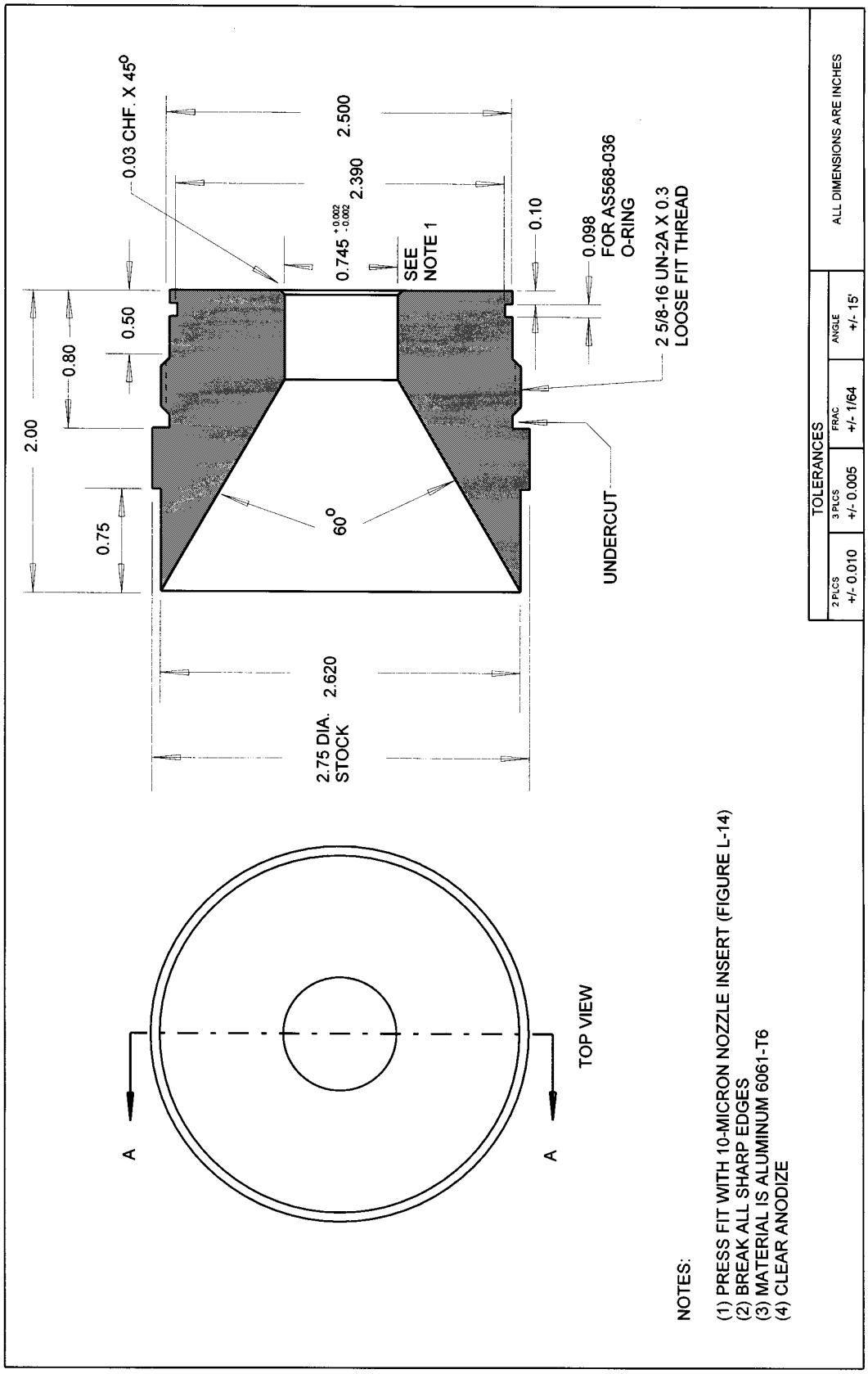


FIGURE L-14. 10-MICRON NOZZLE INSERT

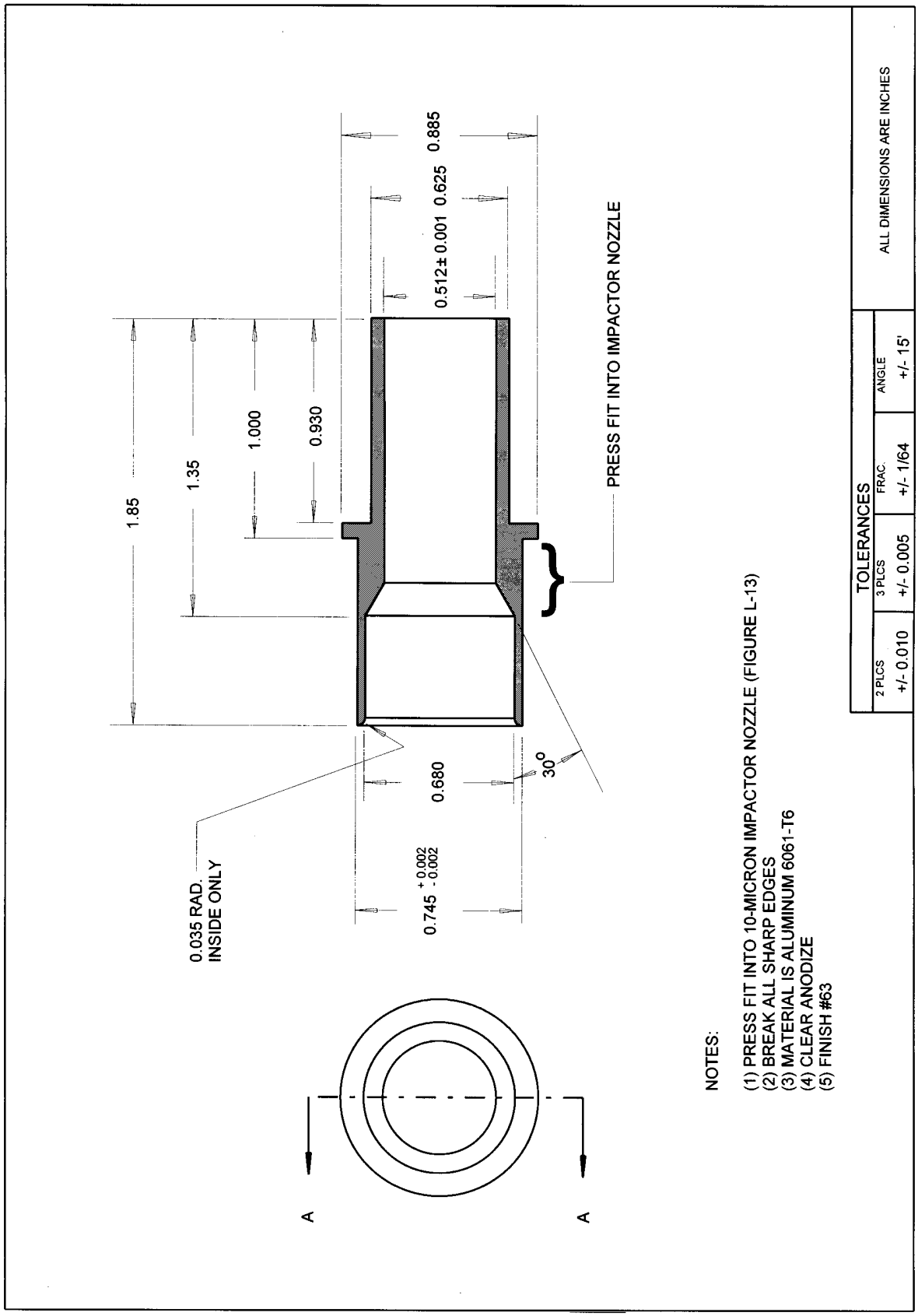


FIGURE L-15. 10-MICRON OUTER TUBE

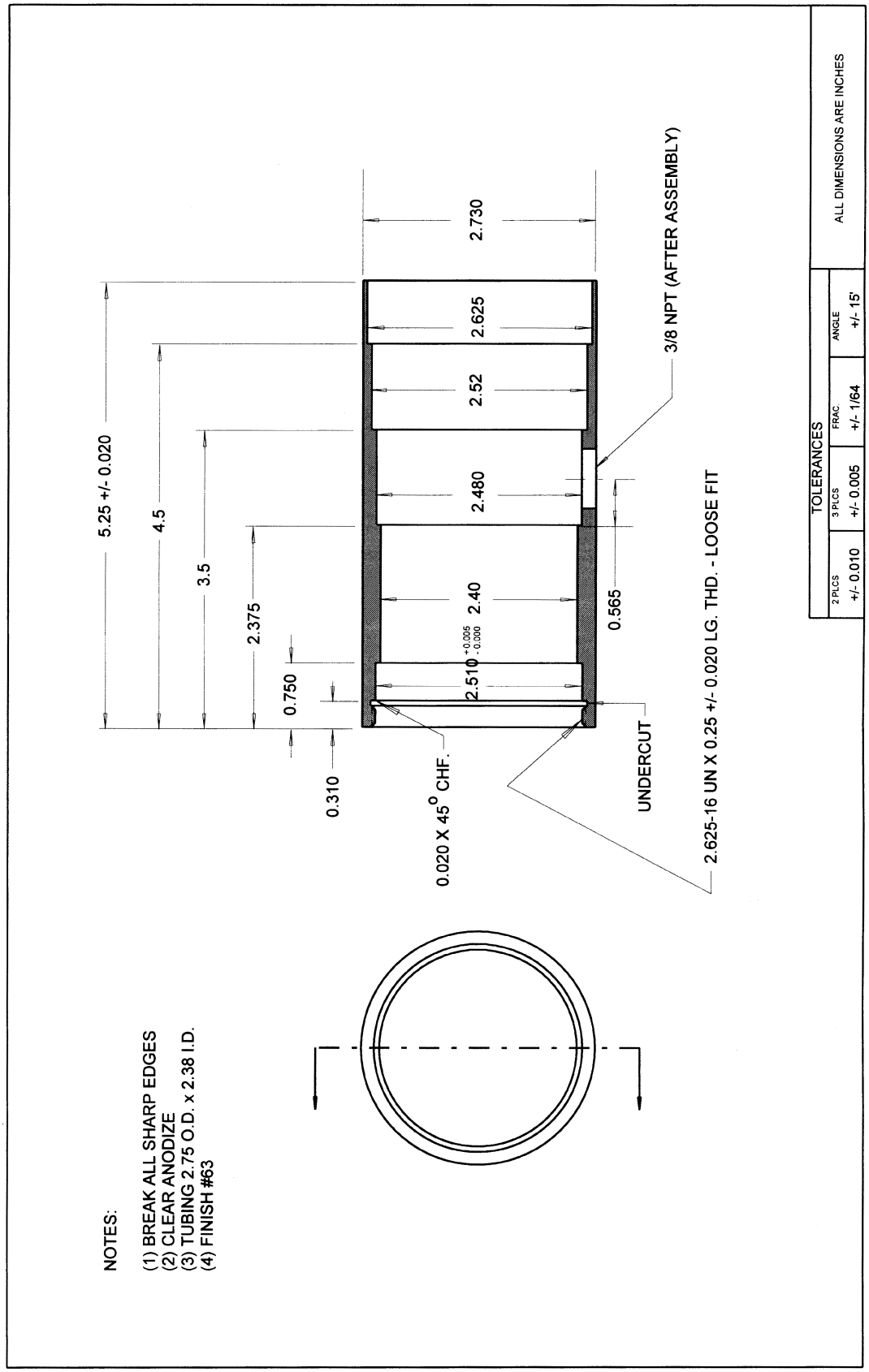
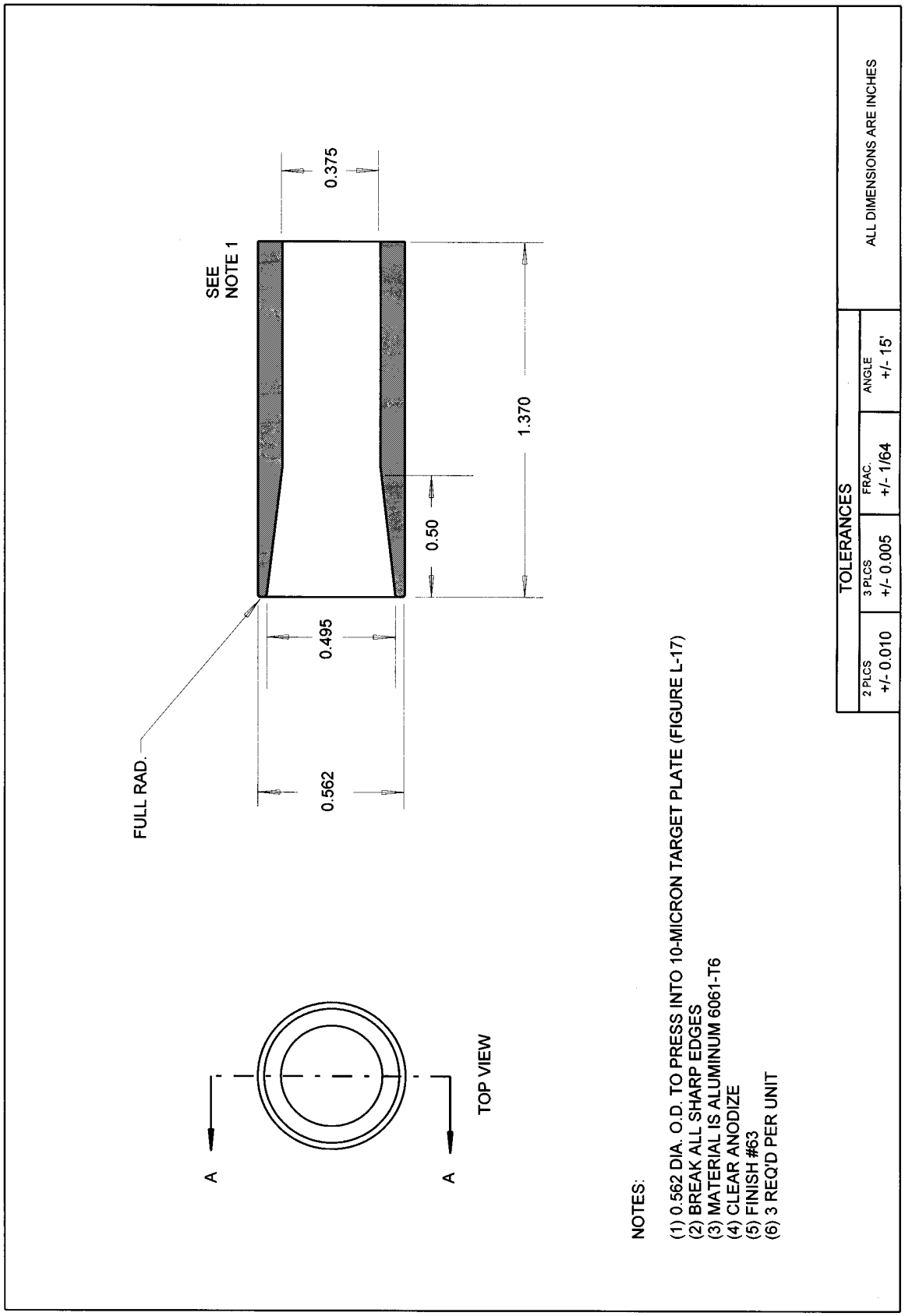


FIGURE L-16. 10-MICRON RECEIVER TUBE



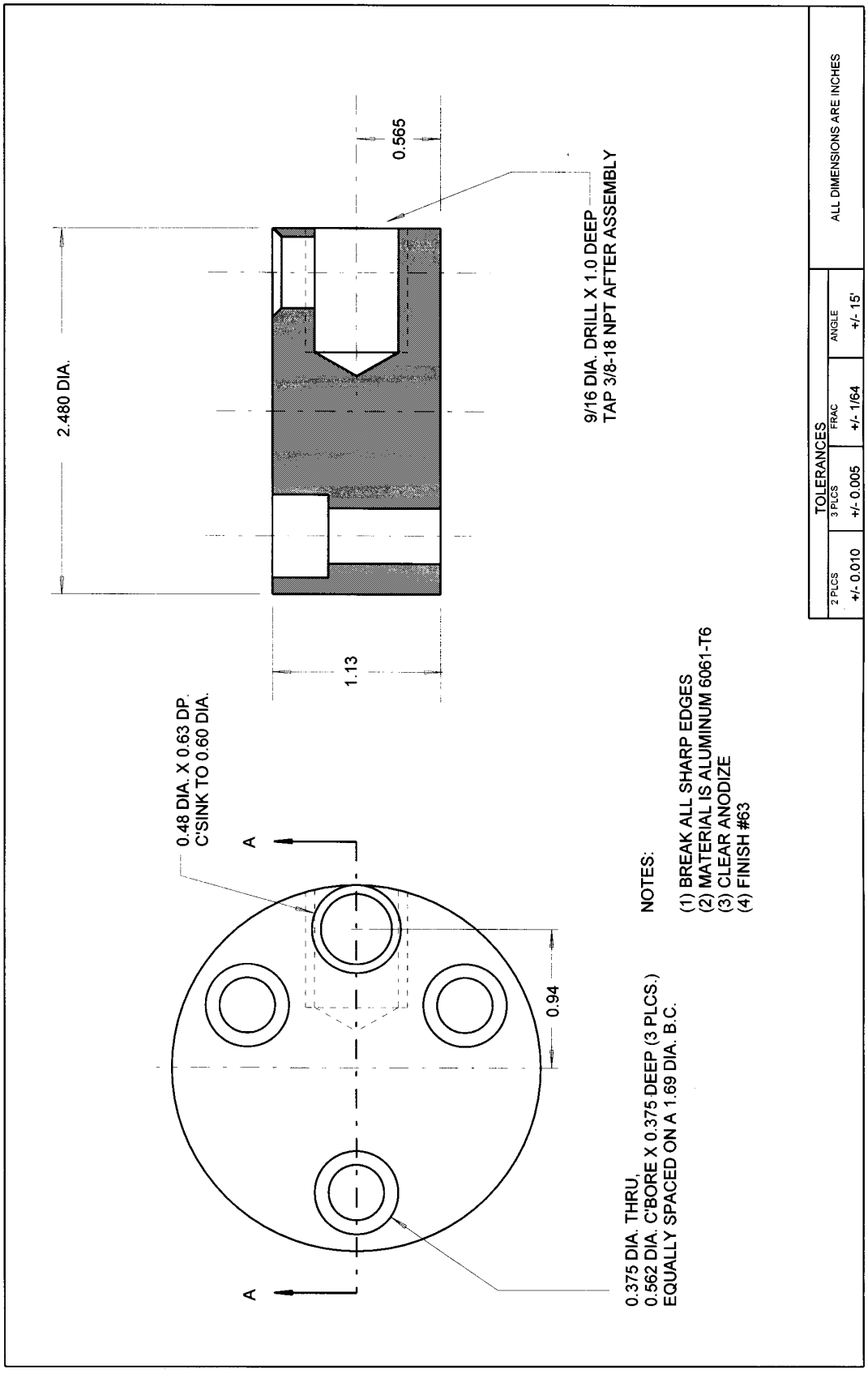


FIGURE L-17. 10-MICRON TARGET PLATE

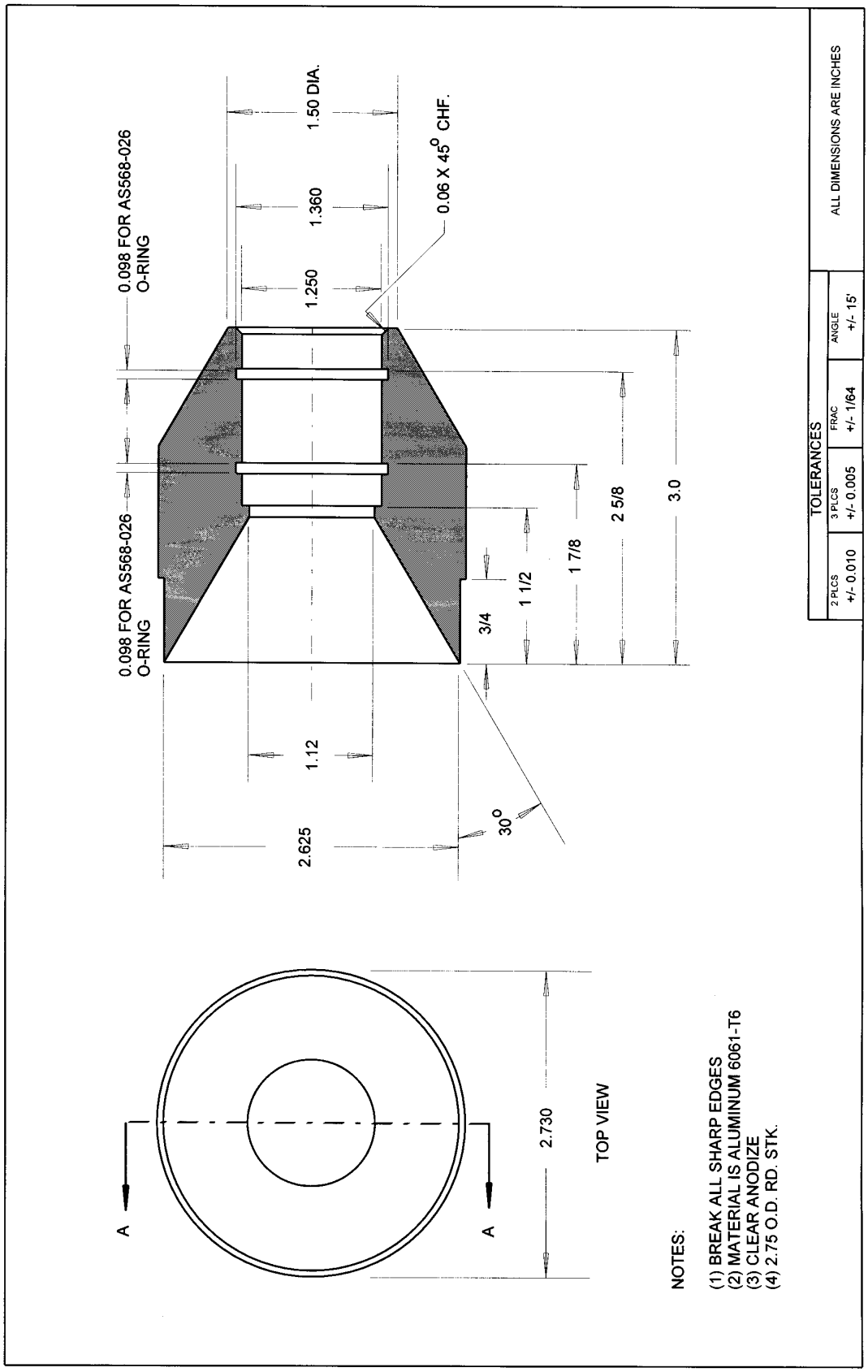


FIGURE L-18. 10-MICRON EXIT ADAPTOR

FIGURE L-19. 10-MICRON DOWN TUBE

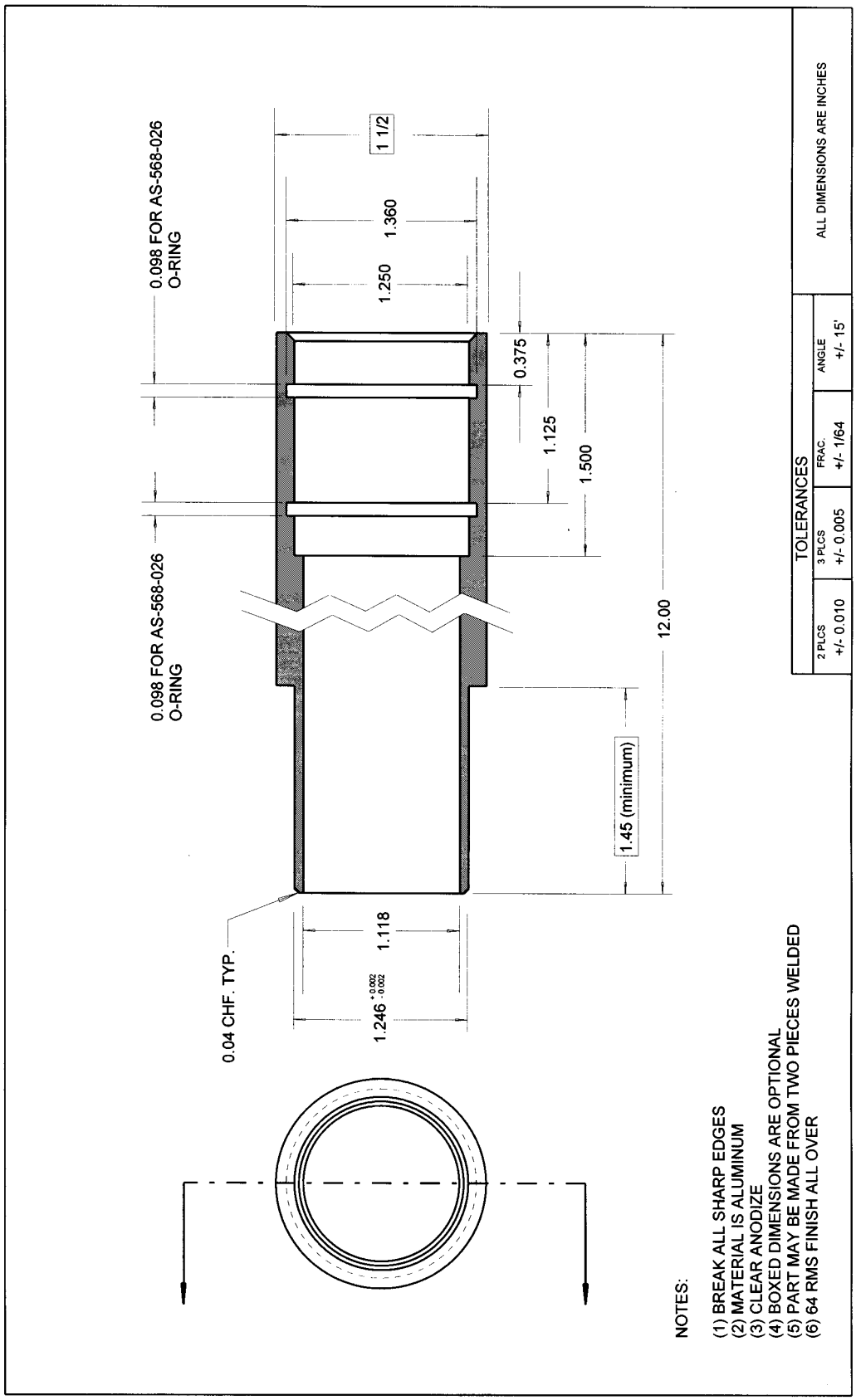


FIGURE L-20. 2.5-MICRON IMPACTOR ASSEMBLY

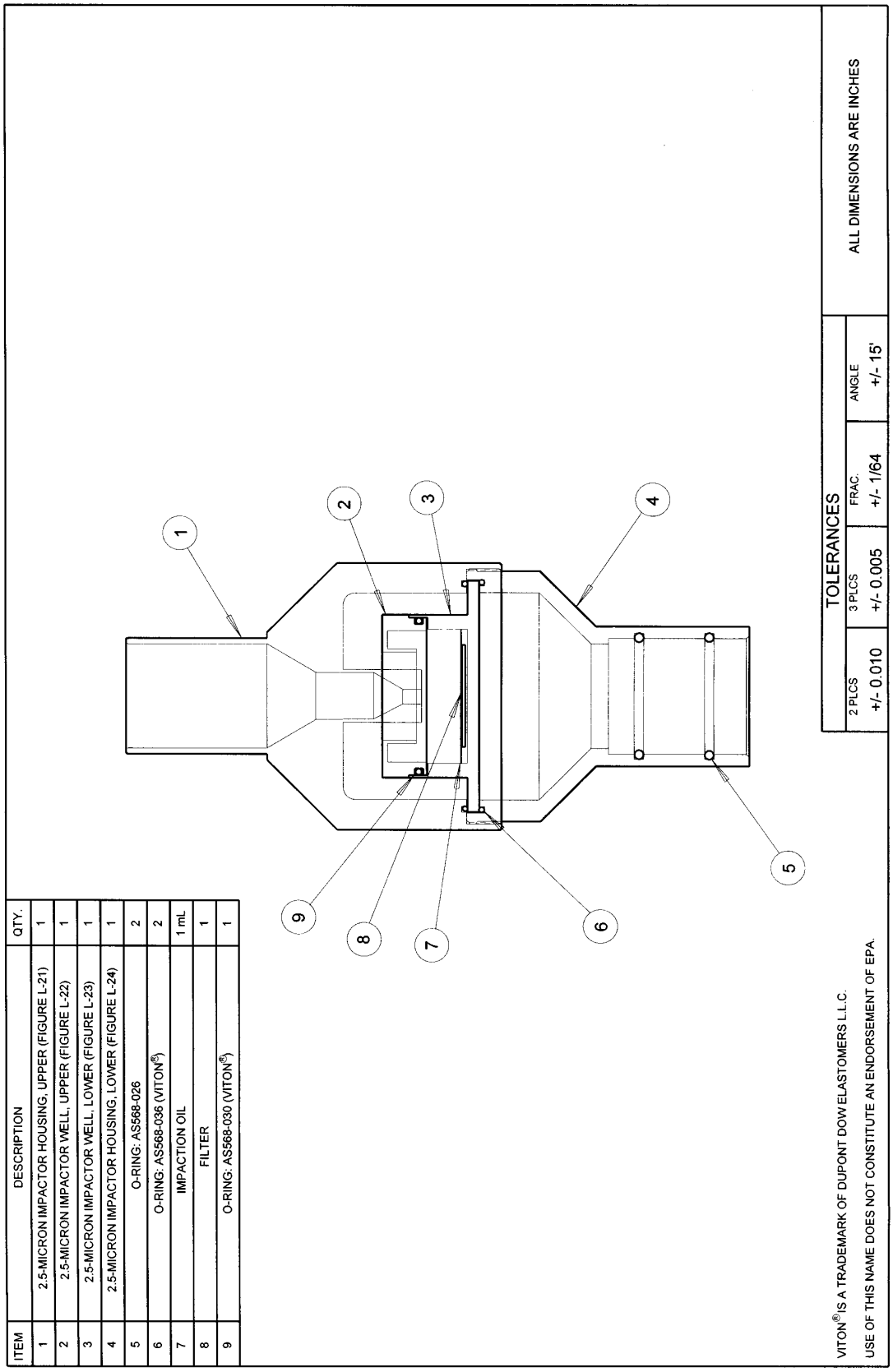
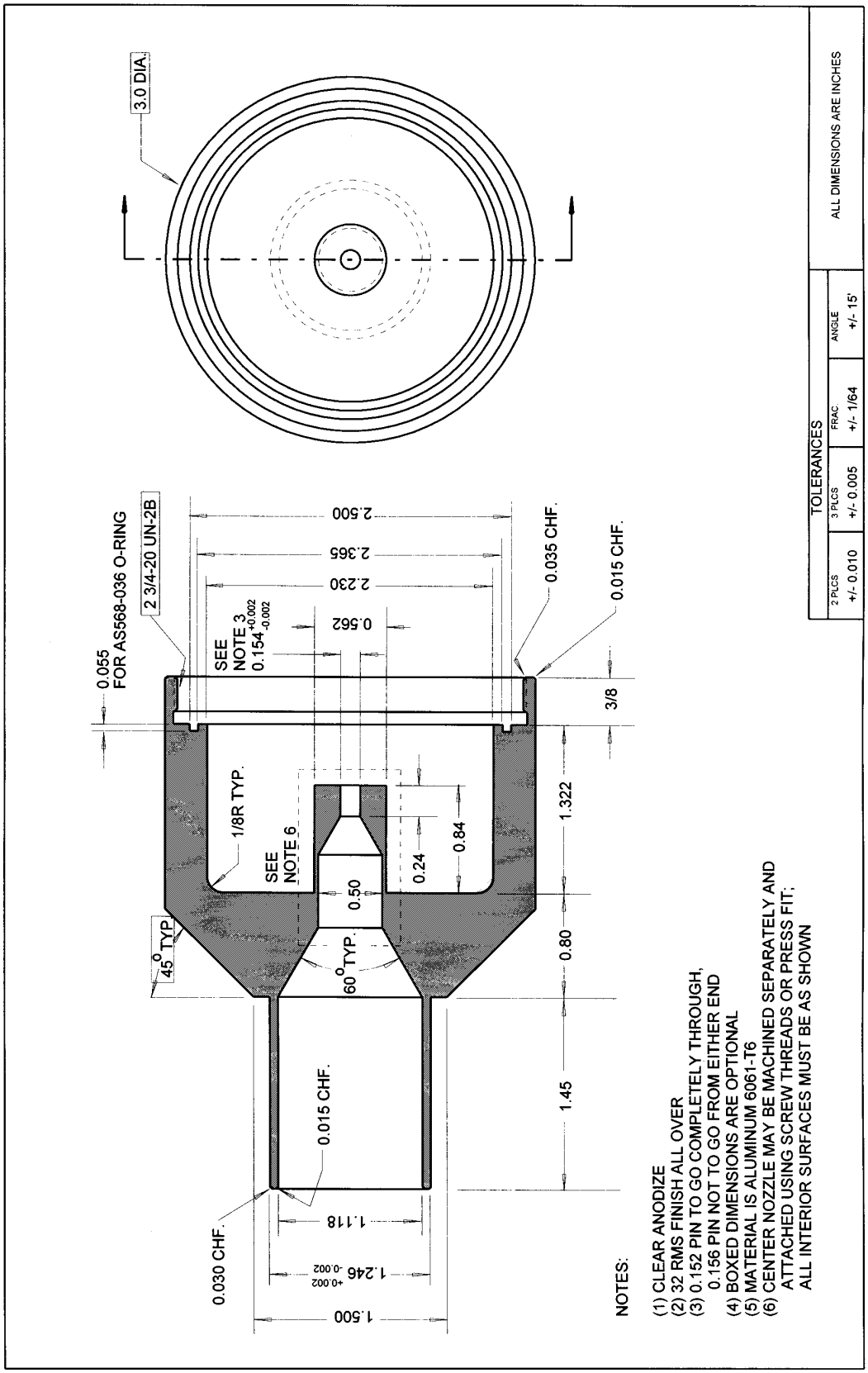


FIGURE L-21. 2.5-MICRON IMPACTOR HOUSING, UPPER



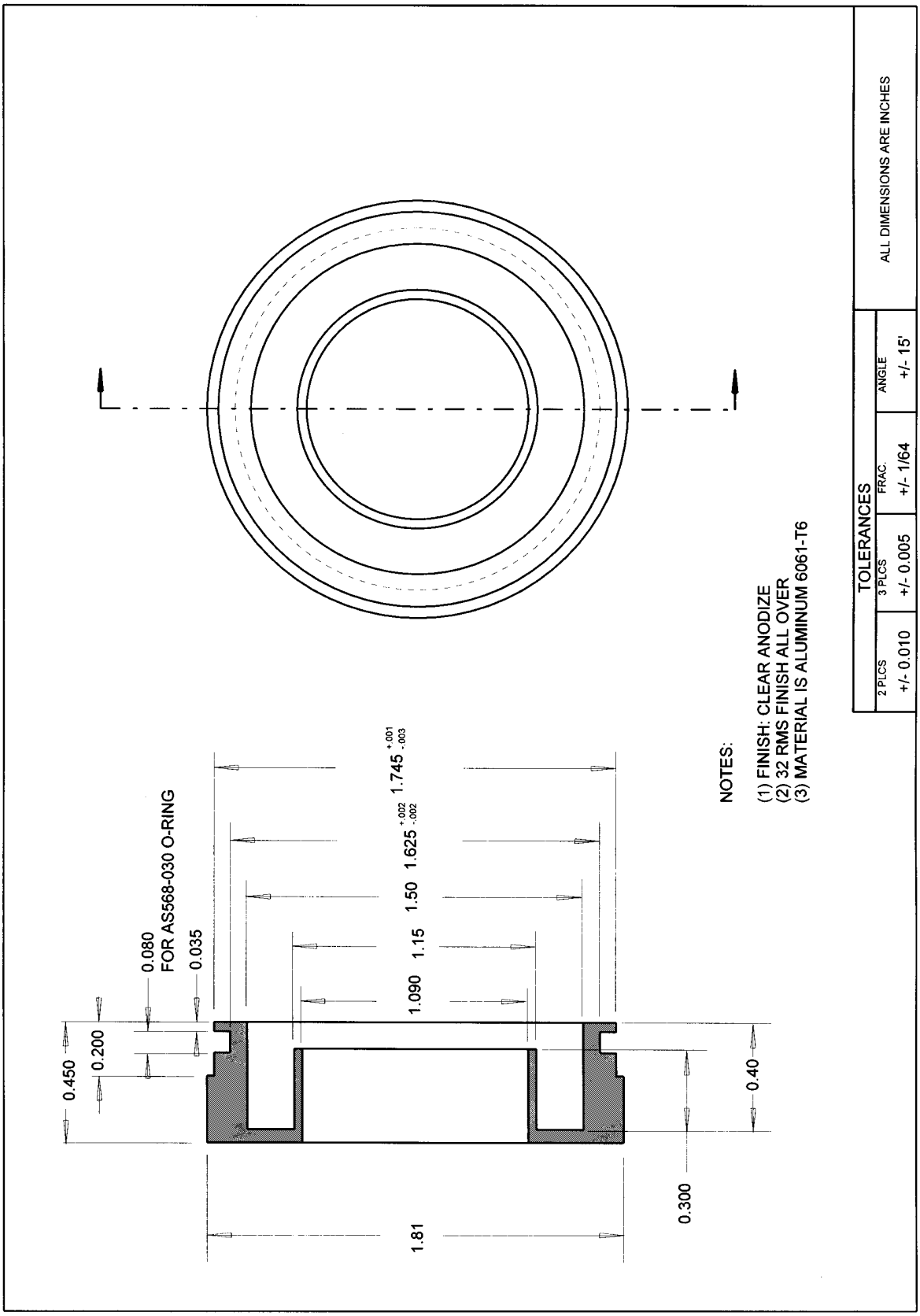


FIGURE L-22. 2.5-MICRON IMPACTOR WELL, UPPER SECTION

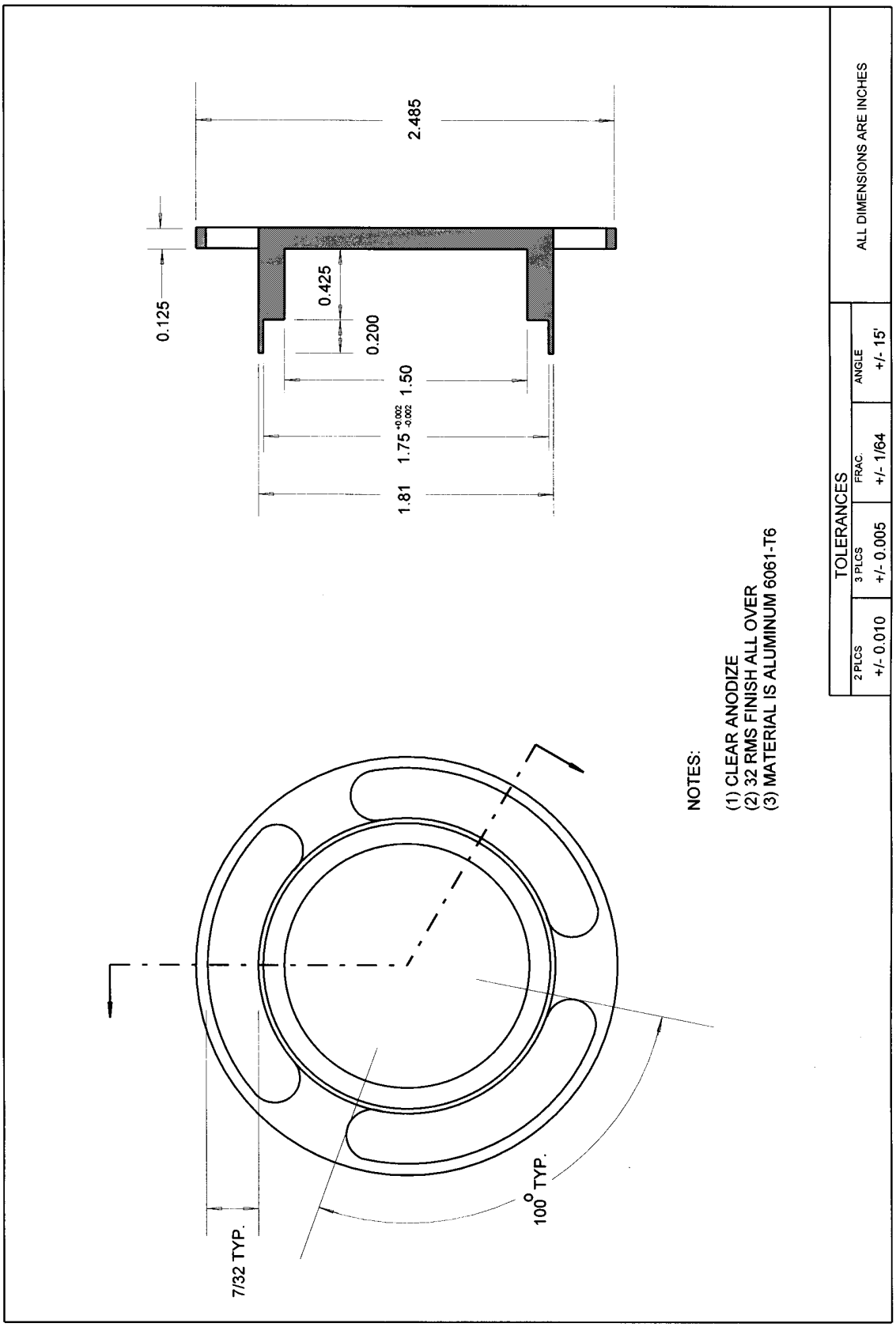


FIGURE L-23. 2.5-MICRON IMPACTOR WELL, LOWER SECTION

FIGURE L-24. 2.5-MICRON IMPACTOR HOUSING, LOWER

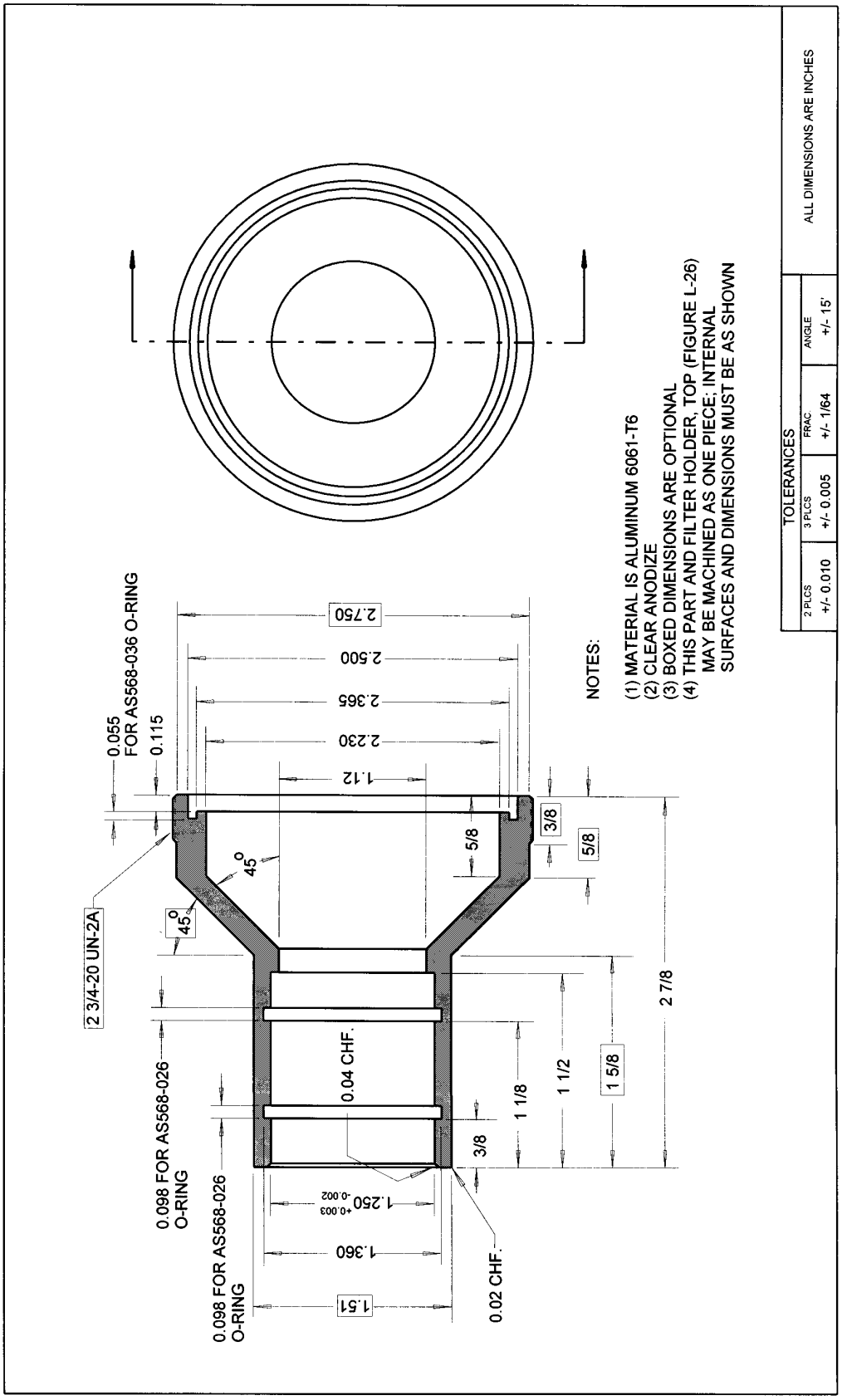
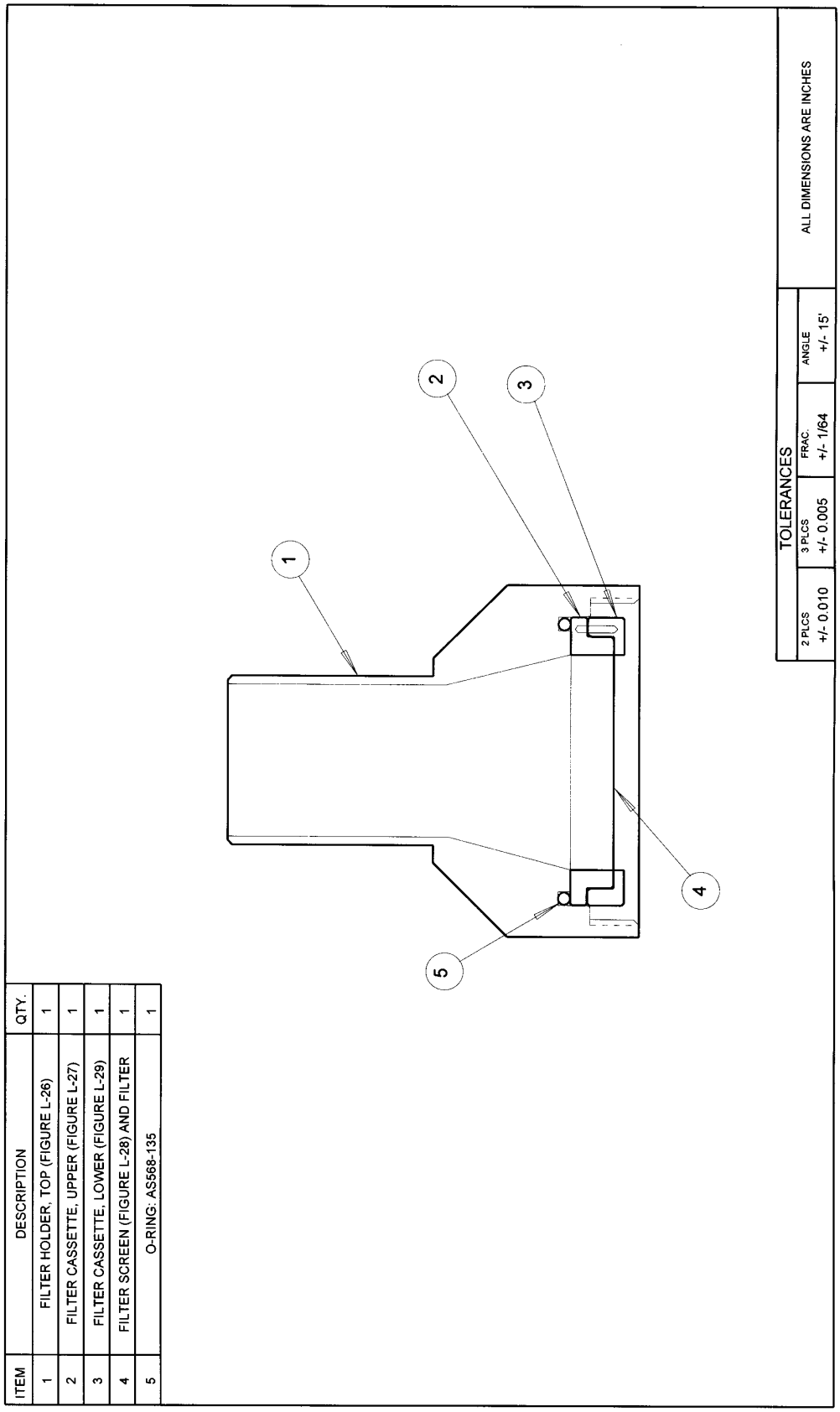


FIGURE L-25. FILTER HOLDER, ASSEMBLY



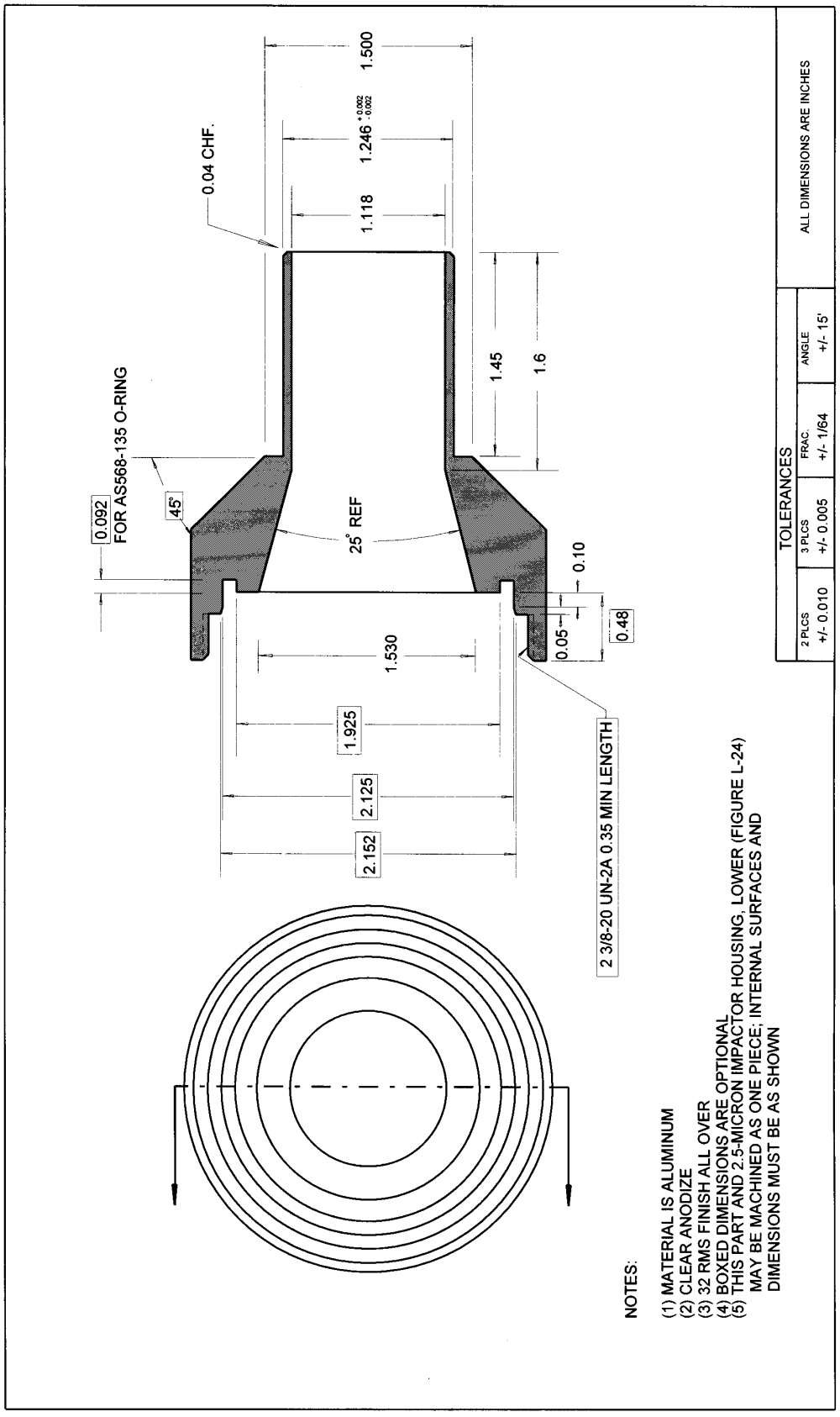


FIGURE L-26. FILTER HOLDER, TOP

FIGURE L-27. FILTER CASSETTE, UPPER SECTION

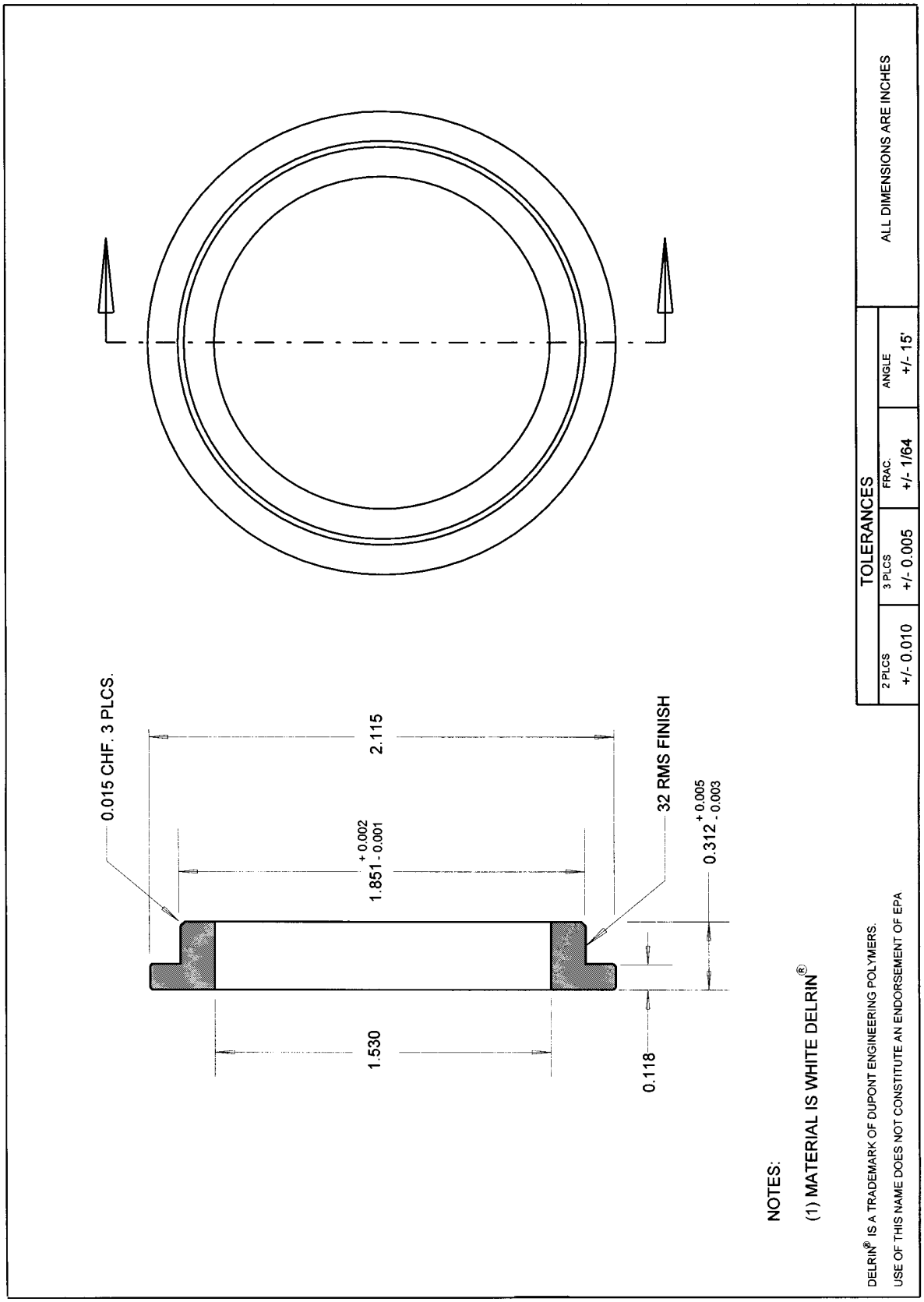


FIGURE L-28. FILTER SCREEN

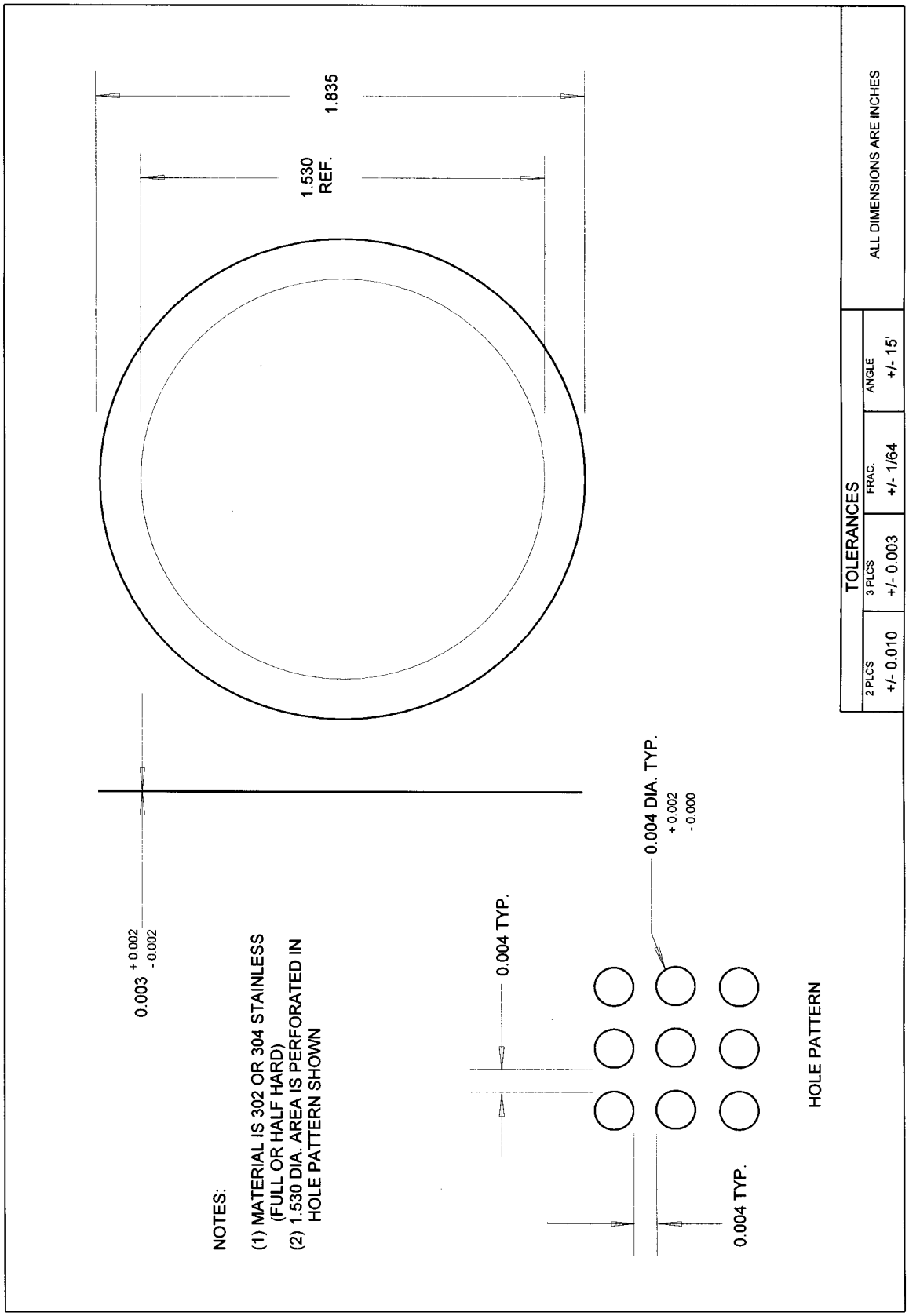
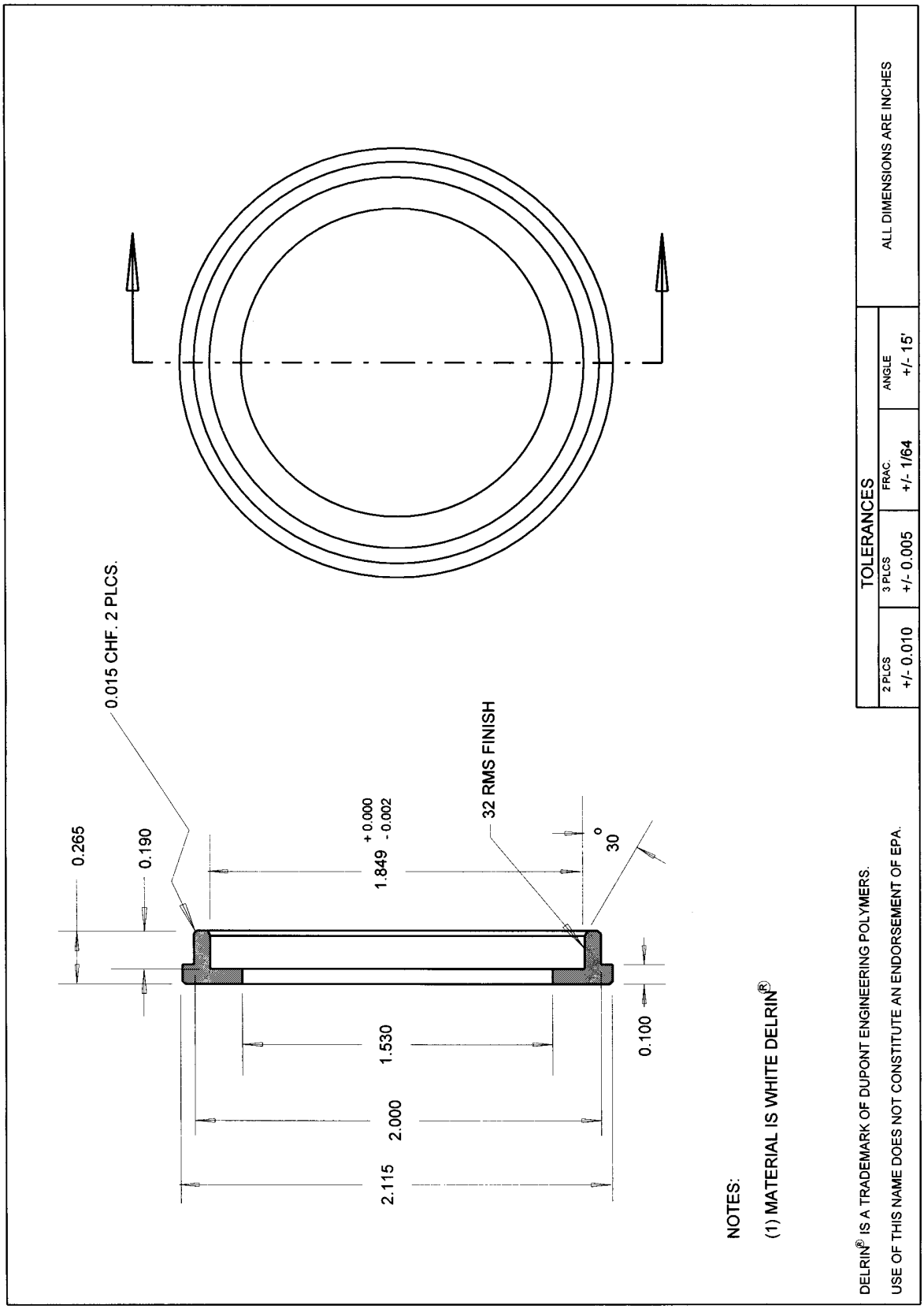


FIGURE L-29. FILTER CASSETTE, LOWER SECTION



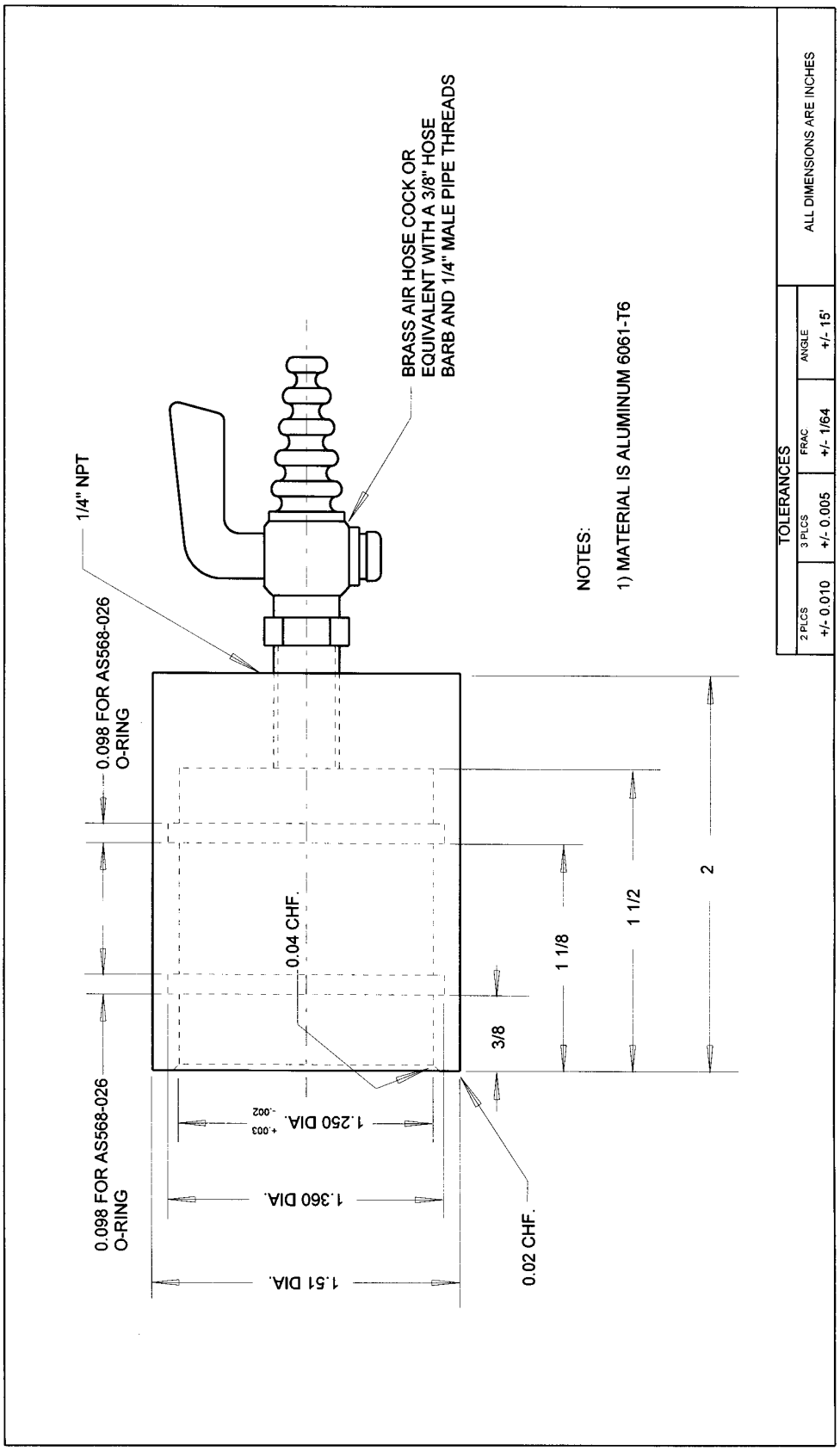


FIGURE L-30. FLOW RATE MEASUREMENT ADAPTER

7. Appendix M is added to read as follows:

Appendix M to Part 50—Reference Method for the Determination of Particulate Matter as PM_{10} in the Atmosphere

1.0 *Applicability.*

1.1 This method provides for the measurement of the mass concentration of particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}) in ambient air over a 24-hour period for purposes of determining attainment and maintenance of the primary and secondary national ambient air quality standards for particulate matter specified in § 50.6 of this chapter. The measurement process is nondestructive, and the PM_{10} sample can be subjected to subsequent physical or chemical analyses. Quality assurance procedures and guidance are provided in part 58, Appendices A and B of this chapter and in references 1 and 2 of section 12.0 of this appendix.

2.0 *Principle.*

2.1 An air sampler draws ambient air at a constant flow rate into a specially shaped inlet where the suspended particulate matter is inertially separated into one or more size fractions within the PM_{10} size range. Each size fraction in the PM_{10} size range is then collected on a separate filter over the specified sampling period. The particle size discrimination characteristics (sampling effectiveness and 50 percent cutpoint) of the sampler inlet are prescribed as performance specifications in part 53 of this chapter.

2.2 Each filter is weighed (after moisture equilibration) before and after use to determine the net weight (mass) gain due to collected PM_{10}. The total volume of air sampled, measured at the actual ambient temperature and pressure, is determined from the measured flow rate and the sampling time. The mass concentration of PM_{10} in the ambient air is computed as the total mass of collected particles in the PM_{10} size range divided by the volume of air sampled, and is expressed in micrograms per actual cubic meter ($\mu g/m^3$).

2.3 A method based on this principle will be considered a reference method only if the associated sampler meets the requirements specified in this appendix and the requirements in part 53 of this chapter, and the method has been designated as a reference method in accordance with part 53 of this chapter.

3.0 *Range.*

3.1 The lower limit of the mass concentration range is determined by the repeatability of filter tare weights, assuming the nominal air sample volume for the sampler. For samplers having an automatic filter-changing mechanism, there may be no upper limit. For samplers that do not have an automatic filter-changing mechanism, the upper limit is determined by the filter mass loading beyond which the sampler no longer maintains the operating flow rate within specified limits due to increased pressure drop across the loaded filter. This upper limit cannot be specified precisely because it is a complex function of the ambient particle size distribution and type, humidity, filter type, and perhaps other factors. Nevertheless, all samplers should be capable of measuring 24-hour PM_{10} mass concentrations of at least 300 $\mu g/m^3$ while maintaining the operating flow rate within the specified limits.

4.0 *Precision.*

4.1 The precision of PM_{10} samplers must be 5 $\mu g/m^3$ for PM_{10} concentrations below 80 $\mu g/m^3$ and 7 percent for PM_{10} concentrations above 80 $\mu g/m^3$, as required by part 53 of this chapter, which prescribes a test procedure that determines the variation in the PM_{10} concentration measurements of identical samplers under typical sampling conditions. Continual assessment of precision via collocated samplers is required by part 58 of this chapter for PM_{10} samplers used in certain monitoring networks.

5.0 *Accuracy.*

5.1 Because the size of the particles making up ambient particulate matter varies over a wide range and the concentration of particles varies with particle size, it is difficult to define the absolute accuracy of PM_{10} samplers. Part 53 of this chapter provides a specification for the sampling effectiveness of PM_{10} samplers. This specification requires that the expected mass concentration calculated for a candidate PM_{10} sampler, when sampling a specified particle size distribution, be within ±10 percent of that calculated for an ideal sampler whose sampling effectiveness is explicitly specified. Also, the particle size for 50 percent sampling effectiveness is required to be 10±0.5 micrometers. Other specifications related to accuracy apply to flow measurement and calibration, filter media, analytical (weighing) procedures, and artifact. The flow rate accuracy of PM_{10} samplers used in certain monitoring networks is required by part 58 of this chapter to be assessed periodically via flow rate audits.

6.0 *Potential Sources of Error.*

6.1 *Volatile Particles.* Volatile particles collected on filters are often lost during shipment and/or storage of the filters prior to the post-sampling weighing [3]. Although shipment or storage of loaded filters is sometimes unavoidable, filters should be reweighed as soon as practical to minimize these losses.

6.2 *Artifacts.* Positive errors in PM_{10} concentration measurements may result from retention of gaseous species on filters [4, 5]. Such errors include the retention of sulfur dioxide and nitric acid. Retention of sulfur dioxide on filters, followed by oxidation to sulfate, is referred to as artifact sulfate formation, a phenomenon which increases with increasing filter alkalinity [6]. Little or no artifact sulfate formation should occur using filters that meet the alkalinity specification in section 7.2.4 of this appendix, Artifact nitrate formation, resulting primarily from retention of nitric acid, occurs to varying degrees on many filter types, including glass fiber, cellulose ester, and many quartz fiber filters [5, 7, 8, 9, 10]. Loss of true atmospheric particulate nitrate during or following sampling may also occur due to dissociation or chemical reaction. This phenomenon has been observed on Teflon® filters [8] and inferred for quartz fiber filters [11, 12]. The magnitude of nitrate artifact errors in PM_{10} mass concentration measurements will vary with location and ambient temperature; however, for most sampling locations, these errors are expected to be small.

6.3 *Humidity.* The effects of ambient humidity on the sample are unavoidable. The filter equilibration procedure in section 9.0 of this appendix is designed to minimize the effects of moisture on the filter medium.

6.4 *Filter Handling.* Careful handling of filters between presampling and postsampling weighings is necessary to avoid errors due to damaged filters or loss of collected particles from the filters. Use of a filter cartridge or cassette may reduce the magnitude of these errors. Filters must also meet the integrity specification in section 7.2.3 of this appendix.

6.5 *Flow Rate Variation.* Variations in the sampler's operating flow rate may alter the particle size discrimination characteristics of the sampler inlet. The magnitude of this error will depend on the sensitivity of the inlet to variations in flow rate and on the particle distribution in the atmosphere during the sampling period. The use of a flow control device, under section 7.1.3 of this appendix, is required to minimize this error.

6.6 *Air Volume Determination.* Errors in the air volume determination may result from errors in the flow rate and/or sampling time measurements. The flow control device serves to minimize errors in the flow rate determination, and an elapsed time meter, under section 7.1.5 of this appendix, is required to minimize the error in the sampling time measurement.

7.0 *Apparatus.*

7.1 PM_{10} Sampler.

7.1.1 The sampler shall be designed to:

(a) Draw the air sample into the sampler inlet and through the particle collection filter at a uniform face velocity.

(b) Hold and seal the filter in a horizontal position so that sample air is drawn downward through the filter.

(c) Allow the filter to be installed and removed conveniently.

(d) Protect the filter and sampler from precipitation and prevent insects and other debris from being sampled.

(e) Minimize air leaks that would cause error in the measurement of the air volume passing through the filter.

(f) Discharge exhaust air at a sufficient distance from the sampler inlet to minimize the sampling of exhaust air.

(g) Minimize the collection of dust from the supporting surface.

7.1.2 The sampler shall have a sample air inlet system that, when operated within a specified flow rate range, provides particle size discrimination characteristics meeting all of the applicable performance specifications prescribed in part 53 of this chapter. The sampler inlet shall show no significant wind direction dependence. The latter requirement can generally be satisfied by an inlet shape that is circularly symmetrical about a vertical axis.

7.1.3 The sampler shall have a flow control device capable of maintaining the sampler's operating flow rate within the flow rate limits specified for the sampler inlet over normal variations in line voltage and filter pressure drop.

7.1.4 The sampler shall provide a means to measure the total flow rate during the sampling period. A continuous flow recorder is recommended but not required. The flow measurement device shall be accurate to ±2 percent.

7.1.5 A timing/control device capable of starting and stopping the sampler shall be used to obtain a sample collection period of 24 ±1 hr (1,440 ±60 min). An elapsed time meter, accurate to within ±15 minutes, shall be used to measure sampling time. This meter is optional for samplers with continuous flow recorders if the sampling time measurement obtained by means of the recorder meets the ±15 minute accuracy specification.

7.1.6 The sampler shall have an associated operation or instruction manual as required by part 53 of this chapter which includes detailed instructions on the calibration, operation, and maintenance of the sampler.

7.2 *Filters.*

7.2.1 *Filter Medium.* No commercially available filter medium is ideal in all respects for all samplers. The user's goals in sampling determine the relative importance of various filter characteristics, e.g., cost, ease of handling, physical and chemical characteristics, etc., and, consequently, determine the choice among acceptable filters. Furthermore, certain types of filters may not be suitable for use with some samplers, particularly under heavy loading conditions (high mass concentrations), because of high or rapid increase in the filter flow resistance that would exceed the capability of the sampler's flow control device. However, samplers equipped with automatic filter-changing mechanisms may allow use of these types of filters. The specifications given below are minimum requirements to ensure acceptability of the filter medium for measurement of PM_{10} mass concentrations. Other filter evaluation criteria should be considered to meet individual sampling and analysis objectives.

7.2.2 *Collection Efficiency.* ≥99 percent, as measured by the DOP test (ASTM–2986) with 0.3 µm particles at the sampler's operating face velocity.

7.2.3 *Integrity.* ±5 µg/m^3 (assuming sampler's nominal 24-hour air sample volume). Integrity is measured as the PM_{10} concentration equivalent corresponding to the average difference between the initial and the final weights of a random sample of test filters that are weighed and handled under actual or simulated sampling conditions, but have no air sample passed through them, i.e., filter blanks. As a minimum, the test procedure must include initial equilibration and weighing, installation on an inoperative sampler, removal from the sampler, and final equilibration and weighing.

7.2.4 *Alkalinity.* <25 microequivalents/gram of filter, as measured by the procedure given in reference 13 of section 12.0 of this appendix following at least two months storage in a clean environment (free from contamination by acidic gases) at room temperature and humidity.

7.3 *Flow Rate Transfer Standard.* The flow rate transfer standard must be suitable for the sampler's operating flow rate and must be calibrated against a primary flow or volume standard that is traceable to the National Institute of Standard and Technology (NIST). The flow rate transfer standard must be capable of measuring the sampler's operating flow rate with an accuracy of ±2 percent.

7.4 *Filter Conditioning Environment.*

7.4.1 *Temperature range.* 15 to 30 C.

7.4.2 *Temperature control.* ±3 C.

7.4.3 *Humidity range.* 20% to 45% RH.

7.4.4 *Humidity control.* ±5% RH.

7.5 *Analytical Balance.* The analytical balance must be suitable for weighing the type and size of filters required by the sampler. The range and sensitivity required will depend on the filter tare weights and mass loadings. Typically, an analytical balance with a sensitivity of 0.1 mg is required for high volume samplers (flow rates >0.5 m^3/min). Lower volume samplers (flow rates <0.5 m^3/min) will require a more sensitive balance.

8.0 *Calibration.*

8.1 *General Requirements.*

8.1.1 Calibration of the sampler's flow measurement device is required to establish traceability of subsequent flow measurements to a primary standard. A flow rate transfer standard calibrated against a primary flow or volume standard shall be used to calibrate or verify the accuracy of the sampler's flow measurement device.

8.1.2 Particle size discrimination by inertial separation requires that specific air velocities be maintained in the sampler's air inlet system. Therefore, the flow rate through the sampler's inlet must be maintained throughout the sampling period within the design flow rate range specified by the manufacturer. Design flow rates are specified as actual volumetric flow rates, measured at existing conditions of temperature and pressure (Q_a).

8.2 *Flow Rate Calibration Procedure.*

8.2.1 PM_{10} samplers employ various types of flow control and flow measurement devices. The specific procedure used for flow rate calibration or verification will vary depending on the type of flow controller and flow rate indicator employed. Calibration is in terms of actual volumetric flow rates (Q_a) to meet the requirements of section 8.1 of this appendix. The general procedure given here serves to illustrate the steps involved in the calibration. Consult the sampler manufacturer's instruction manual and reference 2 of section 12.0 of this appendix for specific guidance on calibration. Reference 14 of section 12.0 of this appendix provides additional information on various other measures of flow rate and their interrelationships.

8.2.2 Calibrate the flow rate transfer standard against a primary flow or volume standard traceable to NIST. Establish a calibration relationship, e.g., an equation or family of curves, such that traceability to the primary standard is accurate to within 2 percent over the expected range of ambient conditions, i.e., temperatures and pressures, under which the transfer standard will be used. Recalibrate the transfer standard periodically.

8.2.3 Following the sampler manufacturer's instruction manual, remove the sampler inlet and connect the flow rate transfer standard to the sampler such that the transfer standard accurately measures the sampler's flow rate. Make sure there are no leaks between the transfer standard and the sampler.

8.2.4 Choose a minimum of three flow rates (actual m^3/min), spaced over the acceptable flow rate range specified for the inlet, under section 7.1.2 of the appendix, that can be obtained by suitable adjustment of the sampler flow rate. In accordance with the sampler manufacturer's instruction manual, obtain or verify the calibration relationship between the flow rate (actual m^3/min) as indicated by the transfer standard and the sampler's flow indicator response. Record the ambient temperature and barometric pressure. Temperature and pressure corrections to subsequent flow indicator readings may be required for certain types of flow measurement devices. When such corrections are necessary, correction on an individual or daily basis is preferable. However, seasonal average temperature and average barometric pressure for the sampling site may be incorporated into the sampler calibration to avoid daily corrections. Consult the sampler manufacturer's instruction manual and reference 2 in section 12.0 of this appendix for additional guidance.

8.2.5 Following calibration, verify that the sampler is operating at its design flow rate (actual m^3/min) with a clean filter in place.

8.2.6 Replace the sampler inlet.

9.0 *Procedure.*

9.1 The sampler shall be operated in accordance with the specific guidance provided in the sampler manufacturer's instruction manual and in reference 2 in section 12.0 of this appendix. The general procedure given here assumes that the sampler's flow rate calibration is based on flow rates at ambient conditions (Q_a) and serves to illustrate the steps involved in the operation of a PM_{10} sampler.

9.2 Inspect each filter for pinholes, particles, and other imperfections. Establish a filter information record and assign an identification number to each filter.

9.3 Equilibrate each filter in the conditioning environment (see 7.4) for at least 24 hours.

9.4 Following equilibration, weigh each filter and record the presampling weight with the filter identification number.

9.5 Install a preweighed filter in the sampler following the instructions provided in the sampler manufacturer's instruction manual.

9.6 (a) Turn on the sampler and allow it to establish run-temperature conditions. Record the flow indicator reading and, if needed, the ambient temperature and barometric pressure. Determine the sampler flow rate (actual m^3/min) in accordance with the instructions provided in the sampler manufacturer's instruction manual.

(b) Note: No onsite temperature or pressure measurements are necessary if the sampler's flow indicator does not require temperature or pressure corrections or if seasonal average temperature and average barometric pressure for the sampling site are incorporated into

the sampler calibration, under section 8.2.4 of this appendix. If individual or daily temperature and pressure corrections are required, ambient temperature and barometric pressure can be obtained by on-site measurements or from a nearby weather station. Barometric pressure readings obtained from airports must be station pressure, not corrected to sea level, and may need to be corrected for differences in elevation between the sampling site and the airport.

9.7 If the flow rate is outside the acceptable range specified by the manufacturer, check for leaks, and if necessary, adjust the flow rate to the specified setpoint. Stop the sampler.

9.8 Set the timer to start and stop the sampler at appropriate times. Set the elapsed time meter to zero or record the initial meter reading.

9.9 Record the sample information (site location or identification number, sample date, filter identification number, and sampler model and serial number).

9.10 Sample for 24±1 hours.

9.11 Determine and record the average flow rate (Q_a) in actual m^3/min for the sampling period in accordance with the instructions provided in the sampler manufacturer's instruction manual. Record the elapsed time meter final reading and, if needed, the average ambient temperature and barometric pressure for the sampling period, in note following section 9.6 of this appendix.

9.12 Carefully remove the filter from the sampler, following the sampler manufacturer's instruction manual. Touch only the outer edges of the filter.

9.13 Place the filter in a protective holder or container, e.g., petri dish, glassine envelope, or manila folder.

9.14 Record any factors such as meteorological conditions, construction activity, fires or dust storms, etc., that might be pertinent to the measurement on the filter information record.

9.15 Transport the exposed sample filter to the filter conditioning environment as soon as possible for equilibration and subsequent weighing.

9.16 Equilibrate the exposed filter in the conditioning environment for at least 24 hours under the same temperature and humidity conditions used for presampling filter equilibration (see section 9.3 of this appendix).

9.17 Immediately after equilibration, reweigh the filter and record the postsampling weight with the filter identification number.

10.0 *Sampler Maintenance.*

10.1 The PM_{10} sampler shall be maintained in strict accordance with the maintenance procedures specified in the sampler manufacturer's instruction manual.

11.0 *Calculations.*

11.1 Calculate the total volume of air sampled as:

$$V = Q_a t$$

where:

V = total air sampled, at ambient temperature and pressure, m^3;

Q_a = average sample flow rate at ambient temperature and pressure, m^3/min; and

t = sampling time, min.

11.2 (a) Calculate the PM_{10} concentration as:

$$PM_{10} = (W_f - W_i) \times 10^6 / V$$

where:

PM_{10} = mass concentration of PM_{10}, $\mu g/m^3$;

W_f, W_i = final and initial weights of filter collecting PM_{1O} particles, g; and

10^6 = conversion of g to µg.

(b) Note: If more than one size fraction in the PM_{10} size range is collected by the sampler, the sum of the net weight gain by each collection filter $[\Sigma(W_f - W_i)]$ is used to calculate the PM_{10} mass concentration.

12.0 *References.*

1. Quality Assurance Handbook for Air Pollution Measurement Systems, Volume I, Principles. EPA–600/9–76–005, March 1976. Available from CERI, ORD Publications, U.S. Environmental Protection Agency, 26 West St. Clair Street, Cincinnati, OH 45268.

2. Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II, Ambient Air Specific Methods. EPA–600/4–77–027a, May 1977. Available from CERI, ORD Publications, U.S. Environmental Protection Agency, 26 West St. Clair Street, Cincinnati, OH 45268.

3. Clement, R.E., and F.W. Karasek. Sample Composition Changes in Sampling and Analysis of Organic Compounds in Aerosols. Int. J. Environ. Analyt. Chem., 7:109, 1979.

4. Lee, R.E., Jr., and J. Wagman. A Sampling Anomaly in the Determination of Atmospheric Sulfate Concentration. Amer. Ind. Hyg. Assoc. J., 27:266, 1966.

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8. Appendix N is added to read as follows:

Appendix N to Part 50—Interpretation of the National Ambient Air Quality Standards for Particulate Matter

1.0 *General.*

(a) This appendix explains the data handling conventions and computations necessary for determining when the annual and 24-hour primary and secondary national ambient air quality standards for PM specified in § 50.7 of this chapter are met. Particulate matter is measured in the ambient air as PM_{10} and $PM_{2.5}$ (particles with an aerodynamic diameter less than or equal to a nominal 10 and 2.5 micrometers, respectively) by a reference method based on Appendix M of this part for PM_{10} and on Appendix L of this part for $PM_{2.5}$, as applicable, and designated in accordance with part 53 of this chapter, or by an equivalent method designated in accordance with part 53 of this chapter. Data handling and computation procedures to be used in making comparisons between reported PM_{10} and $PM_{2.5}$ concentrations and the levels of the PM standards are specified in the following sections.

(b) Data resulting from uncontrollable or natural events, for example structural fires or high winds, may require special consideration. In some cases, it may be appropriate to exclude these data because they could result in inappropriate values to compare with the levels of the PM standards. In other cases, it may be more appropriate to retain the data for comparison with the level of the PM standards and then allow the EPA to formulate the appropriate regulatory response. Whether to exclude, retain, or make adjustments to the data affected by uncontrollable or natural events is subject to the approval of the appropriate Regional Administrator.

(c) The terms used in this appendix are defined as follows:

Average and *mean* refer to an arithmetic mean.

Daily value for PM refers to the 24-hour average concentration of PM calculated or measured from midnight to midnight (local time) for PM_{10} or $PM_{2.5}$.

Designated monitors are those monitoring sites designated in a State PM Monitoring Network Description for spatial averaging in areas opting for spatial averaging in accordance with part 58 of this chapter.

98^{th} *percentile* (used for $PM_{2.5}$) means the daily value out of a year of monitoring data below which 98 percent of all values in the group fall.

99th *percentile* (used for PM_{10}) means the daily value out of a year of monitoring data below which 99 percent of all values in the group fall.

Year refers to a calendar year.

(d) Sections 2.1 and 2.5 of this appendix contain data handling instructions for the option of using a spatially averaged network of monitors for the annual standard. If spatial averaging is not considered for an area, then the spatial average is equivalent to the annual average of a single site and is treated accordingly in subsequent calculations. For example, paragraph (a)(3) of section 2.1 of this appendix could be eliminated since the spatial average would be equivalent to the annual average.

2.0 *Comparisons with the $PM_{2.5}$ Standards.*

2.1 *Annual $PM_{2.5}$ Standard.*

(a) The annual $PM_{2.5}$ standard is met when the 3-year average of the spatially averaged annual means is less than or equal to 15.0 μg/m^3. The 3-year average of the spatially averaged annual means is determined by averaging quarterly means at each monitor to obtain the annual mean $PM_{2.5}$ concentrations at each monitor, then averaging across all designated monitors, and finally averaging for 3 consecutive years. The steps can be summarized as follows:

(1) Average 24-hour measurements to obtain quarterly means at each monitor.

(2) Average quarterly means to obtain annual means at each monitor.

(3) Average across designated monitoring sites to obtain an annual spatial mean for an area (this can be one site in which case the spatial mean is equal to the annual mean).

(4) Average 3 years of annual spatial means to obtain a 3-year average of spatially averaged annual means.

(b) In the case of spatial averaging, 3 years of spatial averages are required to demonstrate that the standard has been met. Designated sites with less than 3 years of data shall be included in spatial averages for those years that data completeness requirements are met. For the annual $PM_{2.5}$ standard, a year meets data completeness requirements when at least 75 percent of the scheduled sampling days for each quarter have valid data. However, years with high concentrations and more than a minimal amount of data (at least 11 samples in each quarter) shall not be ignored just because they are comprised of quarters with less than complete data. Thus, in computing annual spatially averaged means, years containing quarters with at least 11 samples but less than 75 percent data completeness shall be included in the computation if the resulting spatially averaged annual mean concentration (rounded according to the conventions of section 2.3 of this appendix) is greater than the level of the standard.

(c) Situations may arise in which there are compelling reasons to retain years containing quarters which do not meet the data completeness requirement of 75 percent or the minimum number of 11 samples. The use of less than complete data is subject to the approval of the appropriate Regional Administrator.

(d) The equations for calculating the 3-year average annual mean of the $PM_{2.5}$ standard are given in section 2.5 of this appendix.

2.2 *24-Hour $PM_{2.5}$ Standard.*

(a) The 24-hour $PM_{2.5}$ standard is met when the 3-year average of the 98th percentile values at each monitoring site is less than or equal to 65 μg/m^3. This comparison shall be based on 3 consecutive, complete years of air quality data. A year meets data completeness requirements when at least 75 percent of the scheduled sampling days for each quarter have valid data. However, years with high concentrations shall not be ignored just because they are comprised of quarters with less than complete data. Thus, in computing the 3-year average 98th percentile value, years containing quarters with less than 75 percent data completeness shall be included in the computation if the annual 98th percentile value (rounded according to the conventions of section 2.3 of this appendix) is greater than the level of the standard.

(b) Situations may arise in which there are compelling reasons to retain years containing quarters which do not meet the data completeness requirement. The use of less than complete data is subject to the approval of the appropriate Regional Administrator.

(c) The equations for calculating the 3-year average of the annual 98th percentile values is given in section 2.6 of this appendix.

2.3 *Rounding Conventions.* For the purposes of comparing calculated values to the applicable level of the standard, it is necessary to round the final results of the calculations described in sections 2.5 and 2.6 of this appendix. For the annual $PM_{2.5}$ standard, the 3-year average of the spatially averaged annual means shall be rounded to the nearest 0.1 μg/m^3 (decimals 0.05 and greater are rounded up to the next 0.1, and any decimal lower than 0.05 is rounded down to the nearest 0.1). For the 24-hour $PM_{2.5}$ standard, the 3-year average of the annual 98th percentile values shall be rounded to the nearest 1 μg/m^3 (decimals 0.5 and greater are rounded up to nearest whole number, and any decimal lower than 0.5 is rounded down to the nearest whole number).

2.4 *Monitoring Considerations.*

(a) Section 58.13 of this chapter specifies the required minimum frequency of sampling for $PM_{2.5}$. Exceptions to the specified sampling frequencies, such as a reduced frequency during a season of expected low concentrations, are subject to the approval of the appropriate Regional Administrator. Section 58.14 of 40 CFR part 58 and section 2.8 of Appendix D of 40 CFR part 58, specify which monitors are eligible for making comparisons with the PM standards. In determining a spatial mean using two or more monitoring sites operating in a given year, the annual mean for an individual site may be included in the spatial mean if and only if the mean for that site meets the criterion specified in § 2.8 of Appendix D of 40 CFR part 58. In the event data from an otherwise eligible site is excluded from being averaged with data from other sites on the basis of this criterion, then the 3-year mean from that site shall be compared directly to the annual standard.

(b) For the annual $PM_{2.5}$ standard, when designated monitors are located at the same site and are reporting $PM_{2.5}$ values for the same time periods, and when spatial averaging has been chosen, their concentrations shall be averaged before an area-wide spatial average is calculated. Such monitors will then be considered as one monitor.

2.5 *Equations for the Annual $PM_{2.5}$ Standard.*

(a) An annual mean value for $PM_{2.5}$ is determined by first averaging the daily values of a calendar quarter:

Equation 1

$$\bar{x}_{q,y,s} = \frac{1}{n_q}\sum_{i=1}^{n_q} x_{i,q,y,s}$$

where:

$\bar{x}_{q,y,s}$ = the mean for quarter q of year y for site s;

n_q = the number of monitored values in the quarter; and

$x_{i,q,y,s}$ = the i^{th} value in quarter q for year y for site s.

(b) The following equation is then to be used for calculation of the annual mean:

Equation 2

$$\bar{x}_{y,s} = \frac{1}{4}\sum_{q=1}^{4} \bar{x}_{q,y,s}$$

where:

$\bar{x}_{y,s}$ = the annual mean concentration for year y (y = 1, 2, or 3) and for site s; and

$\bar{x}_{q,y,s}$ = the mean for quarter q of year y for site s.

(c) (1) The spatially averaged annual mean for year y is computed by first calculating the annual mean for each site designated to be included in a spatial average, $\bar{x}_{y,s}$, and then computing the average of these values across sites:

Equation 3

$$\bar{x}_{y} = \frac{1}{n_s}\sum_{s=1}^{n_s} \bar{x}_{y,s}$$

where:

$\bar{x}_{y}$ = the spatially averaged mean for year y;

$\bar{x}_{y,s}$ = the annual mean for year y and site s; and

n_s = the number of sites designated to be averaged.

(2) In the event that an area designated for spatial averaging has two or more sites at the same location producing data for the same time periods, the sites are averaged together before using Equation 3 by:

Equation 4

$$\bar{x}_{y,s*} = \frac{1}{n_c}\sum_{s=1}^{n_c} \bar{x}_{y,s}$$

where:

$\bar{x}_{y,s*}$ = the annual mean for year y for the sites at the same location (which will now be considered one site);

n_c = the number of sites at the same location designated to be included in the spatial average; and

$\bar{x}_{y,s}$ = the annual mean for year y and site s.

(d) The 3-year average of the spatially averaged annual means is calculated by using the following equation:

Equation 5

$$\bar{x} = \frac{1}{3}\sum_{y=1}^{3} \bar{x}_y$$

where:

$\bar{x}$ = the 3-year average of the spatially averaged annual means; and

$\bar{x}_y$ = the spatially averaged annual mean for year y.

Example 1—Area Designated for Spatial Averaging That Meets the Primary Annual $PM_{2.5}$ Standard.

a. In an area designated for spatial averaging, four designated monitors recorded data in at least 1 year of a particular 3-year period. Using Equations 1 and 2, the annual means for $PM_{2.5}$ at each site are calculated for each year. The following table can be created from the results. Data completeness percentages for the quarter with the fewest number of samples are also shown.

Table 1.—Results from Equations 1 and 2

		Site #1	Site #2	Site #3	Site #4	Spatial mean
Year 1	Annual mean (μg/m³)	12.7				12.7
	% data completeness	80	0	0	0	
Year 2	Annual mean (μg/m³)	12.6	17.5	15.2		15.05
	% data completeness	90	63	38	0	
Year 3	Annual mean (μg/m³)	12.5	18.5	14.1	16.9	15.50
	% data completeness	90	80	85	50	
3-year mean						14.42

b. The data from these sites are averaged in the order described in section 2.1 of this appendix. Note that the annual mean from site #3 in year 2 and the annual mean from site #4 in year 3 do not meet the 75 percent data completeness criteria. Assuming the 38 percent data completeness represents a quarter with fewer than 11 samples, site #3 in year 2 does not meet the minimum data completeness requirement of 11 samples in each quarter. The site is therefore excluded from the calculation of the spatial mean for year 2. However, since the spatial mean for year 3 is above the level of the standard and the minimum data requirement of 11 samples in each quarter has been met, the annual mean from site #4 in year 3 is included in the calculation of the spatial mean for year 3 and in the calculation of the 3-year average. The 3-year average is rounded to 14.4 μg/m³, indicating that this area meets the annual $PM_{2.5}$ standard.

Example 2—Area With Two Monitors at the Same Location That Meets the Primary Annual $PM_{2.5}$ Standard.

a. In an area designated for spatial averaging, six designated monitors, with two monitors at the same location (#5 and #6), recorded data in a particular 3-year period. Using Equations 1 and 2, the annual means for $PM_{2.5}$ are calculated for each year. The following table can be created from the results.

Table 2.—Results From Equations 1 and 2

Annual mean (μg/m³)	Site #1	Site #2	Site #3	Site #4	Site #5	Site #6	Average of #5 and #6	Spatial mean
Year 1	12.9	9.9	12.6	11.1	14.5	14.6	14.55	12.21
Year 2	14.5	13.3	12.2	10.9	16.1	16.0	16.05	13.39
Year 3	14.4	12.4	11.5	9.7	12.3	12.1	12.20	12.04
3-Year mean								12.55

b. The annual means for sites #5 and #6 are averaged together using Equation 4 before the spatial average is calculated using Equation 3 since they are in the same location. The 3-year mean is rounded to 12.6 μg/m³, indicating that this area meets the annual $PM_{2.5}$ standard.

Example 3—Area With a Single Monitor That Meets the Primary Annual $PM_{2.5}$ Standard.

a. Given data from a single monitor in an area, the calculations are as follows. Using Equations 1 and 2, the annual means for $PM_{2.5}$ are calculated for each year. If the annual means are 10.28, 17.38, and 12.25 μg/m³, then the 3-year mean is:

$$\bar{x} = (1/3) \times (10.28 + 17.38 + 12.25) = 13.303\ \mu g/m^3.$$

b. This value is rounded to 13.3, indicating that this area meets the annual $PM_{2.5}$ standard.

2.6 *Equations for the 24-Hour $PM_{2.5}$ Standard.*

(a) When the data for a particular site and year meet the data completeness requirements in section 2.2 of this appendix, calculation of the 98th percentile is accomplished by the following steps. All the daily values from a particular site and year comprise a series of values (x_1, x_2, x_3, ..., x_n), that can be sorted into a series where each number is equal to or larger than the preceding number ($x_{[1]}$, $x_{[2]}$, $x_{[3]}$, ..., $x_{[n]}$). In this case, $x_{[1]}$ is the smallest number and $x_{[n]}$ is the largest value. The 98th percentile is found from the sorted series of daily values which is ordered from the lowest to the highest number. Compute $(0.98) \times (n)$ as the number ''i.d'', where ''i'' is the integer part of the result and ''d'' is the decimal part of the result. The 98th percentile value for year y, $P_{0.98,\,y}$, is given by Equation 6:

Equation 6

$$P_{0.98,y} = X_{[i+1]}$$

where:

$P_{0.98,y}$ = 98th percentile for year y;

$x_{[i+1]}$ = the $(i+1)^{th}$ number in the ordered series of numbers; and

i = the integer part of the product of 0.98 and n.

(b) The 3-year average 98th percentile is then calculated by averaging the annual 98th percentiles:

Equation 7

$$P_{0.98} = \frac{\sum_{y=1}^{3} P_{0.98,y}}{3}$$

(c) The 3-year average 98th percentile is rounded according to the conventions in section 2.3 of this appendix before a comparison with the standard is made.

Example 4—Ambient Monitoring Site With Every-Day Sampling That Meets the Primary 24-Hour $PM_{2.5}$ Standard.

a. In each year of a particular 3 year period, varying numbers of daily $PM_{2.5}$ values (e.g., 281, 304, and 296) out of a possible 365 values were recorded at a particular site with the following ranked values (in $\mu g/m^3$):

Table 3.—Ordered Monitoring Data For 3 Years

Year 1		Year 2		Year 3	
j rank	X_j value	j rank	X_j value	j rank	X_j value
275	57.9	296	54.3	290	66.0
276	59.0	297	57.1	291	68.4
277	62.2	298	63.0	292	69.8

b. Using Equation 6, the 98th percentile values for each year are calculated as follows:

$$0.98 \times 281 = 275.38 \Rightarrow i+1 = 276 \Rightarrow P_{0.98,1} = X_{[276]} = 59.0 \mu g / m^3$$

$$0.98 \times 304 = 297.92 \Rightarrow i+1 = 298 \Rightarrow P_{0.98,2} = X_{[298]} = 63.0 \mu g / m^3$$

$$0.98 \times 296 = 290.07 \Rightarrow i+1 = 291 \Rightarrow P_{0.98,3} = X_{[291]} = 68.4 \mu g / m^3$$

c. 1. Using Equation 7, the 3-year average 98th percentile is calculated as follows:

$$P_{0.98} = \frac{59.0 + 63.0 + 68.4}{3} = 63.46 \mu g / m^3, \text{ which rounds to } 63 \mu g / m^3.$$

2. Therefore, this site meets the 24-hour $PM_{2.5}$ standard.

3.0 *Comparisons with the PM_{10} Standards.*

3.1 *Annual PM_{10} Standard.*

(a) The annual PM_{10} standard is met when the 3-year average of the annual mean PM_{10} concentrations at each monitoring site is less than or equal to 50 $\mu g/m^3$. The 3-year average of the annual means is determined by averaging quarterly means to obtain annual mean PM_{10} concentrations for 3 consecutive, complete years at each monitoring site. The steps can be summarized as follows:

(1) Average 24-hour measurements to obtain a quarterly mean.

(2) Average quarterly means to obtain an annual mean.

(3) Average annual means to obtain a 3-year mean.

(b) For the annual PM_{10} standard, a year meets data completeness requirements when at least 75 percent of the scheduled sampling days for each quarter have valid data. However, years with high concentrations and more than a minimal amount of data (at least 11 samples in each quarter) shall not be ignored just because they are comprised of quarters with less than complete data. Thus, in computing the 3-year average annual mean concentration, years containing quarters with at least 11 samples but less than 75 percent data completeness shall be included in the computation if the annual mean concentration (rounded according to the conventions of section 2.3 of this appendix) is greater than the level of the standard.

(c) Situations may arise in which there are compelling reasons to retain years containing quarters which do not meet the data completeness requirement of 75 percent or the minimum number of 11 samples. The use of less than complete data is subject to the approval of the appropriate Regional Administrator.

(d) The equations for calculating the 3-year average annual mean of the PM_{10} standard are given in section 3.5 of this appendix.

3.2 *24-Hour PM_{10} Standard.*

(a) The 24-hour PM_{10} standard is met when the 3-year average of the annual 99th percentile values at each monitoring site is less than or equal to 150 $\mu g/m^3$. This comparison shall be based on 3 consecutive, complete years of air quality data. A year meets data completeness requirements when at least 75 percent of the scheduled sampling days for each quarter have valid data. However, years with high concentrations shall not be ignored just because they are comprised of quarters with less than complete data. Thus, in computing the 3-year average of the annual 99th percentile values, years containing quarters with less than 75 percent data completeness shall be included in the computation if the annual 99th percentile value (rounded according to the conventions of section 2.3 of this appendix) is greater than the level of the standard.

(b) Situations may arise in which there are compelling reasons to retain years containing quarters which do not meet the data completeness requirement. The use of less than complete data is subject to the approval of the appropriate Regional Administrator.

(c) The equation for calculating the 3-year average of the annual 99th percentile values is given in section 2.6 of this appendix.

3.3 *Rounding Conventions.* For the annual PM_{10} standard, the 3-year average of the annual PM_{10} means shall be rounded to the nearest 1 $\mu g/m^3$ (decimals 0.5 and greater are

rounded up to the next whole number, and any decimal less than 0.5 is rounded down to the nearest whole number). For the 24-hour PM_{10} standard, the 3-year average of the annual 99th percentile values of PM_{10} shall be rounded to the nearest 10 μg/m³ (155 μg/m³ and greater would be rounded to 160 μg/m³ and 154 μg/m³ and less would be rounded to 150 μg/m³).

3.4 *Monitoring Considerations.* Section 58.13 of this chapter specifies the required minimum frequency of sampling for PM_{10}. Exceptions to the specified sampling frequencies, such as a reduced frequency during a season of expected low concentrations, are subject to the approval of the appropriate Regional Administrator. For making comparisons with the PM_{10} NAAQS, all sites meeting applicable requirements in part 58 of this chapter would be used.

3.5 *Equations for the Annual PM_{10} Standard.*

(a) An annual arithmetic mean value for PM_{10} is determined by first averaging the 24-hour values of a calendar quarter using the following equation:

Equation 8

$$\bar{x}_{q,y} = \frac{1}{n_q}\sum_{i=1}^{n_q} x_{i,q,y}$$

where:

$\bar{x}_{q,y}$ = the mean for quarter q of year y;

n_q = the number of monitored values in the quarter; and

$x_{i,q,y}$ = the i^{th} value in quarter q for year y.

(b) The following equation is then to be used for calculation of the annual mean:

Equation 9

$$\bar{x}_y = \frac{1}{4}\sum_{q=1}^{4} \bar{x}_{q,y}$$

where:

$\bar{x}_y$ = the annual mean concentration for year y, (y=1, 2, or 3); and

$x_{q,y}$ = the mean for a quarter q of year y.

(c) The 3-year average of the annual means is calculated by using the following equation:

Equation 10

$$\bar{x} = \frac{1}{3}\sum_{y=1}^{3} \bar{x}_y$$

where:

$\bar{x}$ = the 3-year average of the annual means; and

$\bar{x}_y$ = the annual mean for calendar year y.

Example 5—Ambient Monitoring Site That Does Not Meet the Annual PM_{10} Standard.

a. Given data from a PM_{10} monitor and using Equations 8 and 9, the annual means for PM_{10} are calculated for each year. If the annual means are 52.42, 82.17, and 63.23 μg/m³, then the 3-year average annual mean is:

$$\bar{x} = (1/3) \times (52.42 + 82.17 + 63.23) = 65.94, \text{ which is rounded to } 66\ \mu g/m^3.$$

b. Therefore, this site does not meet the annual PM_{10} standard.

3.6 *Equation for the 24-Hour PM_{10} Standard.*

(a) When the data for a particular site and year meet the data completeness requirements in section 3.2 of this appendix, calculation of the 99th percentile is accomplished by the following steps. All the daily values from a particular site and year comprise a series of values (x_1, x_2, x_3, ..., x_n) that can be sorted into a series where each number is equal to or larger than the preceding number ($x_{[1]}$, $x_{[2]}$, $x_{[3]}$, ..., $x_{[n]}$). In this case, $x_{[1]}$ is the smallest number and x[n] is the largest value. The 99th percentile is found from the sorted series of daily values which is ordered from the lowest to the highest number. Compute (0.99) × (n) as the number ''i.d'', where ''i'' is the integer part of the result and ''d'' is the decimal part of the result. The 99th percentile value for year y, $P_{0.99,y}$, is given by Equation 11:

Equation 11

$$P_{0.99,y} = X_{[i+1]}$$

where:

$P_{0.99,y}$ = the 99th percentile for year y;

$x_{[i+1]}$ = the (i+1)th number in the ordered series of numbers; and

i = the integer part of the product of 0.99 and n.

(b) The 3-year average 99th percentile value is then calculated by averaging the annual 99th percentiles:

Equation 12

$$P_{0.99} = \frac{\sum_{y=1}^{3} P_{0.99,y}}{3}$$

(c) The 3-year average 99th percentile is rounded according to the conventions in section 3.3 of this appendix before a comparison with the standard is made.

Example 6—Ambient Monitoring Site With Sampling Every Sixth Day That Meets the Primary 24-Hour PM_{10} Standard.

a. In each year of a particular 3 year period, varying numbers of PM_{10} daily values (e.g., 110, 98, and 100) out of a possible 121 daily values were recorded at a particular site with the following ranked values (in μg/m³):

Table 4.—Ordered Monitoring Data For 3 Years

Year 1		Year 2		Year 3	
j rank	X_j value	j rank	X_j value	j rank	X_j value
108	120	96	143	98	140
109	128	97	148	99	144
110	130	98	150	100	147

b. Using Equation 11, the 99th percentile values for each year are calculated as follows:

$$0.99 \times 110 = 108.9 \Rightarrow i+1 = 109 \Rightarrow P_{0.99,1} = X_{[109]} = 128 \mu g/m^3$$

$$0.99 \times 98 = 97.02 \Rightarrow i+1 = 98 \Rightarrow P_{0.99,2} = X_{[98]} = 150 \mu g/m^3$$

$$0.99 \times 100 = 99 \Rightarrow i + 1 = 100 \Rightarrow P_{0.99,3} = X_{[100]} = 147 \mu g / m^3$$

c. 1. Using Equation 12, the 3-year average 99th percentile is calculated as follows:

$$\frac{128 + 50 + 147}{3} = 141.7 \ \mu g / m^3 \text{ rounds to } 140 \mu g / m^3.$$

2. Therefore, this site meets the 24-hour PM_{10} standard.

[FR Doc. 97–18577 Filed 7–17–97; 8:45 am]

BILLING CODE 6560–50–F

Federal Register

Wednesday,

January 5, 2005

Part II

Environmental Protection Agency

40 CFR Part 81

Air Quality Designations and Classifications for the Fine Particles (PM2.5) National Ambient Air Quality Standards; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 81

[OAR–2003–0061; FRL–7856–1]

RIN–2060–AM04

Air Quality Designations and Classifications for the Fine Particles (PM2.5) National Ambient Air Quality Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule sets forth the initial air quality designations and classifications for all areas in the United States, including Indian country, for the fine particles (PM2.5) National Ambient Air Quality Standards (NAAQS). The EPA is issuing this rule so that citizens will know whether the air quality where they live and work is healthful or unhealthful. Health studies have shown significant associations between exposure to PM2.5 and premature death from heart or lung disease. Fine particles can also aggravate heart and lung diseases and have been linked to effects such as cardiovascular symptoms, cardiac arrhythmias, heart attacks, respiratory symptoms, asthma attacks, and bronchitis. These effects can result in increased hospital emissions, emergency room visits, absences from school or work, and restricted activity days.

Individuals that may be particularly sensitive to PM2.5 exposure include people with heart or lung disease, older adults, and children. This rule establishes the boundaries for areas designated as nonattainment, unclassifiable, or attainment/unclassifiable. This rule does not establish or address State and Tribal obligations for planning and control requirements that apply to nonattainment areas for the PM2.5 standards. The EPA will publish a separate rule which will set forth the planning and control requirements that apply to nonattainment areas for the PM2.5 standards.

DATES: The effective date of this rule is April 5, 2005.

ADDRESSES: The EPA has established a docket for this action under Docket ID NO. OAR–2003–0061. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket*. Although listed in the index, some information is not publicly available *i.e.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in the EDOCKET or in hard copy at the Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m. Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Office of Air and Radiation Docket and Information Center is (202) 566–1742. In addition, we have placed a copy of the rule and a variety of materials regarding designations on EPA's designation Web site at: *http://www.epa.gov/oar/oaqps/particles/designations/index.htm* and on the Tribal Web site at: *http://www/epa.gov/air/tribal*.

FOR FURTHER INFORMATION CONTACT: Designations: Mr. Rich Damberg, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Mail Code C504–02, Research Triangle Park, NC 27711, phone number (919) 541–5592 or by e-mail at: *damberg.rich@epa.gov*.

Designations and Part 81 Code of Federal Regulations: Dr. Larry D. Wallace, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Mail Code C504–02, Research Triangle Park, NC 27711, phone number (919) 541–0906 or by e-mail at: *wallace.larry@epa.gov*.

Technical Issues Related to Designations: Mr. Thomas Rosendahl, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Mail Code C504–02, Research Triangle Park, NC 27711, phone number (919) 541–5314 or by e-mail at: *rosendahl.tom@epa.gov*.

PM2.5 Air Quality Data Issues: Mr. Mark Schmidt, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Mail Code C304–01, Research Triangle Park, NC 27711, phone number (919) 541–5314 or by e-mail at: *schmidt.mark@epa.gov*.

Regional Office Contacts:

Region I—Alison Simcox (617) 918–1684,

Region II—Kenneth Fradkin (212) 637–3702,

Region III—Denny Lohman (215) 814–2191,

Region IV—Steve Scofield (404) 562–9034,

Region V—John Summerhays (312) 886–6067,

Region VI—Joe Kordzi (214) 665–7186,

Region VII—Amy Algoe-Eakin (913) 551–7942,

Region VIII—Libby Faulk (303) 312–6083,

Region IX—Eleanor Kaplan (415) 744–1286,

Region X—Keith Rose (206) 553–1949.

SUPPLEMENTARY INFORMATION: The public may inspect the rule and the technical support information at the following locations:

Regional offices	States
Dave Conroy, Acting Branch Chief, Air Programs Branch, EPA New England, I Congress Street, Suite 1100, Boston, MA 02114–2023, (617) 918–1661.	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
Raymond Werner, Chief, Air Programs Branch, EPA Region II, 290 Broadway, 25th Floor, New York, NY 10007–1866, (212) 637–4249.	New Jersey, New York, Puerto Rico, and Virgin Islands.
Makeba Morris, Branch Chief, Air Quality Planning Branch, EPA Region III, 1650 Arch Street, Philadelphia, PA 19103–2187, (215) 814–2187.	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, and West Virginia.
Richard A. Schutt, Chief, Regulatory Development Section, EPA Region IV, Sam Nun Atlanta Federal Center, 61 Forsyth, Street, SW, 12th Floor, Atlanta, GA 30303, (404) 562–9033.	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee.
Jay Bortzer, Chief, Air Programs Branch, EPA Region V, 77 West Jackson Street, Chicago, IL 60604, (312) 886–4447.	Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.
Donna Ascenzi, Acting Associate Director, Air Programs, EPA Region VI, 1445 Ross Avenue, Dallas, TX 75202, (214) 665–2725.	Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.
Joshua A. Tapp, Chief, Air Programs Branch, EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101–2907, (913) 551–7606.	Iowa, Kansas, Missouri, and Nebraska.

Regional offices	States
Richard R. Long, Director, Air and Radiation Program, EPA Region VIII, 999 18th, Suite 300, Denver, CO 80202, (303) 312–6005.	Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming.
Steven Barhite, Air Planning Office, EPA Region IX, 75 Hawthorne Street, San Francisco, CA 94105, (415) 972–3980.	Arizona, California, Guam, Hawaii, and Nevada.
Mahbubul Islam, Manager, State and Tribal Air Programs, EPA Region X, Office of Air, Waste, and Toxics, Mail Code OAQ–107, 1200 Sixth Avenue, Seattle, WA 98101, (206) 553–6985.	Alaska, Idaho, Oregon, and Washington.

Table of Contents

I. Preamble Glossary of Terms and Acronyms

The following are abbreviations of terms used in the preamble.

CAA Clean Air Act
CFR Code of Federal Regulations
CMAQ Congestion Mitigation Air Quality
CMSA Consolidated Metropolitan Statistical Area
D.C. District of Columbia
EPA Environmental Protection Agency
FR Federal Register
MPO Metropolitan Planning Organizations
MSA Metropolitan Statistical Area
NAAQS National Ambient Air Quality Standard
NO_X Nitrogen Oxides
NOA Notice of Availability
NPR Notice of Proposed Rulemaking
NSR New Source Review
OMB Office of Management and Budget
RTC Response to Comment
SIP State Implementation Plan
TAR Tribal Authority Rule
TEA–21 Transportation Equity Act for the 21st Century
TPY Tons Per Year
TSD Technical Support Document
U.S. United States
VOC Volatile Organic Compounds

II. What Is the Purpose of This Document?

The purpose of this document is to announce and promulgate designations and boundaries for areas of the country with respect to the PM2.5 NAAQS in accordance with the requirements of the CAA. The list of areas in each State, the boundaries of each area, and the designation of each area, appear in the table at the end of this final rule. This rule was signed by the EPA Administrator, Mike Leavitt, on December 17, 2004. Several steps were taken to announce that this rule is available. We posted the notice on several EPA Web sites and provided a copy of the rule to States and Tribes.

III. What Are Fine Particles?

Fine particles in the atmosphere are made up of a complex mixture of components. Common constituents include: sulfate (SO_4); nitrate (NO_3); ammonium (NH4); elemental carbon; a great variety of organic compounds; water; and inorganic material (including metals, dust, sea salt, and other trace elements), which often is categorized as ''crustal'' material. Airborne particles with a nominal aerodynamic diameter of 2.5 micrometers or less (a micrometer is one-millionth of a meter; 2.5 micrometers is less than about one-thirtieth the thickness of a human hair) are considered to be ''fine particles,'' and are also known as PM2.5. ''Primary'' particles are emitted directly into the air as a solid or liquid particle (*e.g.*, elemental carbon and organic particles from diesel engines or burning activities). ''Secondary'' particles (*e.g.*, sulfate and nitrate) form in the atmosphere as a result of various chemical transformations of gaseous precursors such as sulfur dioxide (SO_2) and oxides of nitrogen (NO_X).

IV. What Are the Health Concerns Addressed by the PM2.5 Standard?

Epidemiological studies have shown a significant association between elevated PM2.5 levels and a number of serious health effects, including premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems such as heart attacks and cardiac arrhythmia. Individuals particularly sensitive to PM2.5 exposure include older adults, people with heart and lung disease, and children.

More information on the health effects of PM2.5 can be found at the following Web site: *http://www.epa.gov/ttn/naaqs/pm/pm25_index.html*.

V. What Is the Chronology of Events Leading Up to This Rule?

This section summarizes the relevant activities leading up to today's action, including promulgation of the PM2.5 NAAQS and litigation challenging that standard. The CAA establishes a process for air quality management through the establishment and implementation of the NAAQS. After the promulgation of a new or revised NAAQS, EPA is required to designate areas, pursuant to section 107(d)(1) of the CAA, as attainment, nonattainment, or unclassifiable.

On July 18, 1997, EPA revised the NAAQS for particulate matter to add new standards for PM2.5, using PM2.5 as the indicator for the pollutant. The EPA established health-based (primary) annual and 24-hour standards for PM2.5 (62 FR 38652). The annual standard is a level of 15 micrograms per cubic meter, based on a 3-year average of annual mean PM2.5 concentrations. The

24-hour standard is a level 65 micrograms per cubic meter, based on a 3-year average of the 98th percentile of 24-hour concentrations. The EPA established the standards based on significant evidence and numerous health studies demonstrating that serious health effects are associated with exposures to particulate matter.

The PM2.5 NAAQS were challenged by numerous litigants and in May 1999, the U.S. Court of Appeals for the D.C. Circuit issued a decision remanding, but not vacating, the standards. *American Trucking Assoc.* v. *EPA*, 175 F.3d 1027, 1047–48, *on rehearing* 195 F.3d 4 (D.C. Cir., 1999). The EPA sought review of two aspects of that decision in the U.S. Supreme Court. The Supreme Court upheld the PM2.5 standards. *EPA* v. *American Trucking Assoc.*, 531 U.S. 457 (2001). In March 2002, the D.C. Circuit rejected all remaining challenges to the PM2.5 standards, *American Trucking Assoc.* v. *EPA*, 283 F.3d 355 (D.C. Cir., 2002). Since final resolution of the litigation over the PM2.5 NAAQS, EPA has been acting to implement the standards.

The process for designating areas following promulgation of a new or revised NAAQS is contained in section 107(d)(1) of the CAA. In June 1998, Congress adopted the Transportation Equity Act for the 21st Century (TEA–21). Section 6102(c)(1)(d) of TEA–21 amended section 107 of the CAA by extending the time period for EPA to initiate the designations process for the PM2.5 NAAQS until 3 calendar years of air quality data, measured at Federal Reference Method monitors, were gathered. The EPA and State air quality agencies initiated the monitoring process for the PM2.5 NAAQS in 1999, and deployed all air quality monitors by January 2001. The EPA is designating areas across the country for the PM2.5 NAAQS based upon air quality monitoring data from these monitors for calendar years 2001–2003.

VI. What Are the Clean Air Act (CAA) Requirements for Air Quality Designations and What Action has EPA Taken to Meet These Requirements?

This section summarizes the provisions of section 107(d)(1) of the CAA which governs the process that States and EPA must follow in order to recommend and promulgate designations. Following the promulgation of a new or revised standard, each State Governor or Tribal leader has an opportunity to recommend air quality designations, including the appropriate boundaries for areas, to EPA. By no later than 120 days prior to promulgating designations, EPA is required to notify States or Tribes of any intended modifications to their boundaries that EPA deems necessary. States and Tribes then have an opportunity to provide a demonstration as to why the proposed modification indicated by EPA is inappropriate. Whether or not a State or Tribe provides a recommendation, EPA must promulgate the designation that it deems appropriate.

In April 2003, EPA requested that States and Tribes submit their designation recommendations and supporting documentation to EPA by February 15, 2004. After receiving recommendations from the States and Tribes and carefully reviewing and evaluating each recommendation, EPA on June 28 and 29, 2004, provided a response to each State and Tribe indicating whether or not EPA intended to make modifications to the initial recommendations, and explaining EPA's reasons for making any such modifications. The EPA provided an opportunity for States and Tribes to respond to any proposed modifications to their initial boundary recommendations until September 1, 2004. In response to our June 28 and 29, 2004 letters, EPA received letters from many States and Tribes suggesting changes to EPA's modifications and providing additional information. The EPA evaluated each supplemental letter, and all of the timely technical support information provided, before arriving at the final designation decisions reflected in today's action. Some of the designations reflect our modifications to the State and Tribal recommendations. We have placed these State and Tribal letters, and our responses to the issues contained in them, in the EPA docket for this action.

Tribal designation activities are covered under the authority of section 301(d) of the CAA. This provision of the CAA authorizes EPA to treat eligible Indian Tribes in the same manner as States. Pursuant to section 301(d)(2), we promulgated regulations, known as the Tribal Authority Rule (TAR), on February 12, 1999. 63 FR 7254, codified at 40 CFR 49 (1999). This rule specifies those provisions of the CAA for which it is appropriate to treat Tribes as States. Under the TAR, Tribes may choose to develop and implement their own CAA programs, but are not required to do so. The TAR also establishes procedures and criteria by which Tribes may request from EPA a determination of eligibility for such treatment. The designations process contained in section 107(d) of the CAA is included among those provisions determined to be appropriate by EPA for treatment of Tribes in the same manner as States. As authorized by the TAR, Tribes may request an opportunity to submit designation recommendations to us. In cases where Tribes do not make their own recommendations, EPA, in consultation with the Tribes, will promulgate the designation that EPA deems appropriate on their behalf. All Tribes were invited to submit recommendations concerning designations for PM2.5.

The EPA worked with the Tribes that requested an opportunity to submit designation recommendations. Eligible Tribes were provided an opportunity to submit their own recommendations and supporting documentation. The EPA reviewed the recommendations made by Tribes and, in consultation with the Tribes, made modifications as deemed necessary and appropriate. Under the TAR, Tribes generally are not subject to the same submission schedules imposed by the CAA on States.

VII. What Guidance Did EPA Issue and How Did EPA Apply the Statutory Requirements and Applicable Guidance To Determine Boundaries for the PM2.5 NAAQS?

Section 107(d)(1)(A)(I) of the CAA defines a nonattainment area as an area that is violating an ambient standard or is contributing to air quality in a nearby area that is violating the standard. If an area meets either prong of this definition, then EPA is obligated to designate the area as nonattainment. Section 107(d)(1)(A)(iii) provides that any area which EPA cannot designate on the basis of available information as meeting or not meeting the standards should be designated unclassifiable.

In April 2003, EPA issued designation guidance concerning how to determine the boundaries for PM2.5 nonattainment areas.[1] The guidance provided that EPA would use the 3 most recent calendar years of monitoring data for PM2.5 to determine each county's designation. For today's PM2.5 designations, we are basing our decision on air quality monitoring data from calendar years 2001–2003. When evaluating individual areas, we started with the premise that data recorded by a PM2.5 monitor in most cases represents air quality throughout the area in which it is located. In addition, we considered the county boundary as the basic jurisdictional boundary for determining the extent of the area reflected by the PM2.5 monitor. As a result, if a PM2.5

[1] *See* ''Designations for the Fine Particle National Ambient Air Quality Standards.'' memorandum to Regional Administrators, Regions I–X, from Jeffrey R. Holmstead, Assistant Administrator, OAR, dated April 1, 2003.

monitor was violating the standard based on the 2001–2003 data, at a minimum we designated the entire county where that monitor is located as nonattainment. We made exceptions to this approach in a few very large western counties where a significant geographic feature such as a mountain range divided a county, resulting in different air quality in different parts of the county. In such cases, we considered designations of partial counties to be appropriate. After identifying the counties with violating monitors, we then proceeded to identify nearby counties that were potentially contributing to the violation(s) at the monitors.

In assessing whether nearby areas contributed to a violation, EPA started with the Consolidated Metropolitan Statistical Area (CMSA) and the Metropolitan Statistical Area (MSA) as the presumptive boundaries for PM2.5 nonattainment areas. A metropolitan area, as defined by the Office of Management and Budget (OMB) in 1999, consisted of a single MSA in some cases, or a CMSA in other cases. These metropolitan areas provide boundaries for the geographic extent of urban areas. We suggested the use of metropolitan area boundaries as the presumptive boundaries for urban nonattainment areas for air quality purposes, based upon evidence that violations of the PM2.5 air quality standards generally include a significant urban-scale contribution as well as a regional contribution. The actual size of each nonattainment area may be larger or smaller than the presumptive boundaries, depending upon the application of the nine factors contained in the April 2003 designations guidance for PM2.5.

In June 2003, OMB released a new list of metropolitan area descriptions. Because we had already issued the April 2003 designations guidance which recommended use of the 1999 OMB metropolitan definitions as a starting point, and because States and Tribes were already actively using this guidance in their planning efforts, we decided that it would be disruptive to recommend the use of the 2003 OMB definitions as the presumptive boundaries. Instead, we issued a second guidance memorandum in February 2004, which indicated that we would continue to consider the 1999 MSA boundaries as the presumptive boundaries, but that States should nevertheless take into consideration the 2003 OMB revised MSA boundaries. We particularly urged consideration of the 2003 MSA boundaries for those counties that OMB added to an existing metropolitan area due to growth, or because of a high degree of social and economic integration with the primary urban area.[2]

The April 2003 guidance memorandum described nine factors that EPA would take into consideration in determining appropriate nonattainment area boundaries, whether larger or smaller than the presumptive boundaries: (1) Emissions and air quality in adjacent areas (including adjacent CMSAs and MSAs), (2) air quality in potentially included versus excluded areas, (3) population density and degree of urbanization including commercial development in included versus excluded areas, (4) traffic and commuting patterns, (5) expected growth (including extent, pattern and rate of growth), (6) meteorology (weather/transport patterns), (7) geography/topography (*e.g.*, mountain ranges or other air basin boundaries), (8) jurisdictional boundaries (*e.g.*, counties, air districts, Reservations, etc.), and (9) level of existing controls on emission sources.

In assessing emissions under the first factor, we developed a ''weighted emissions score'' that valued the effect of direct emissions of PM2.5 and its precursors that contribute to ''urban excess'' PM2.5 concentrations at monitor sites. The ''urban excess'' concentrations for each PM2.5 component (direct or precursor emissions) are calculated from two PM2.5 speciation monitors by subtracting the regional concentration from the urban concentration for each component. The methodology we used to calculate urban excess concentration and the weighted emission score is explained in more detail in the technical support document (TSD).

We used this metric to compare the relative emissions contribution of different counties in and around each metropolitan area. Using this approach, we were able to take into consideration, in a single metric, the county-level emissions of carbonaceous particles, inorganic particles, SO_2, and NO_X (all of which contribute to PM2.5 formation) in the vicinity of each violating monitor. By comparing weighted emissions scores across counties in a metropolitan area, EPA was able to identify those counties having the highest estimated emissions contribution to the local nonattainment problem. In addition, by examining the data from the urban speciation monitors, we could draw some conclusions concerning the likely sources of emissions contributing to the violation. Knowing the likely sources of the emissions, we could better evaluate which of the nearby counties had emissions likely to be contributing to the ambient concentrations at the violating monitor.

Evaluation of the weighted emissions score and speciation data was an important element in our nine factor analysis, and we believe that it provided a reasonable tool for evaluating the relative contribution of nearby areas to violations at a monitor, given the variety of precursors and sources that participate in the formation of PM2.5. Further discussion of the weighted emissions score, and area-specific explanations of its application, appear in the TSD.

In some cases, considering the factors and additional information provided by the State, we determined that only part of a nearby county (*e.g.*, the part of the county that contained the significant sources of contributing emissions) should be considered as contributing to the violation at the monitor, and therefore included only a portion of that adjacent county in the nonattainment area. In other cases, we determined that the emissions from an identifiable large power plant in a county were contributing to the violations in a nearby area. In these cases, we concluded that it was appropriate to designate only the portion of the county where the source is located, even if that portion is not contiguous with the remainder of the nonattainment area. We adopted this approach where we determined, following the nine factor analysis, that it would be inappropriate to include other portions of a county, merely because those portions lay between the large stationary source and the remainder of the designated nonattainment area. We selected the boundaries for these noncontiguous portions of nonattainment areas by relying on legally recognized governmental boundaries (*e.g.*, townships, tax districts, or census blocks) in which the source is located.

We believe that the individual facts and circumstances of each area must be considered in determining whether to include a county as contributing to a particular nonattainment problem. Thus, our guidance does not establish bright lines or cut-points for how a particular factor is applied. For example, the guidance does not identify a set amount of a pollutant, or a specific level of commuting between counties, that would automatically require a county to be included in a nonattainment area as a contributing

[2] See ''Additional Guidiance on Defining Area Boundaries for PM–2.5 Designations,'' memorandum to Air Division Directors. Regions I–X, from Lydia N. Wegman, Director, AQSSD, dated February 13, 2004.

county. We analyzed the information provided by each State or Tribe in its recommendation letter, subsequently submitted information, and any other pertinent information available to EPA, in order to determine whether a county should be designated nonattainment. We evaluated each State's or Tribe's designation recommendation in light of the nine factors, bringing to bear our best technical and policy judgement. If the result of the evaluation showed that a county, whether inside or outside of the CMSA or MSA contributes to the violation in a nearby area with a violating monitor, we designated the area as nonattainment.

In a small number of areas, EPA concluded that there was insufficient information to designate a given area as either nonattainment or attainment/unclassifiable. In these instances, we have designated the area as unclassifiable. In each instance, these areas had violating monitors for the years 2000–2002, but incomplete data or other data issues for the years 2001–2003. Further explanation of the unclassifiable designations may be found in the TSD for this action.

The EPA did not rely on planned or potential regional PM2.5 reduction strategies in making decisions regarding nonattainment designations, even if those strategies predict that an area may attain the standard in the future. We recognize that some areas with a violating monitor may be projected to come into attainment in the future without additional local emission controls because of State and/or national programs that will reduce transported emissions. However, the CAA requires EPA to make nonattainment designations based on current data. While we cannot consider projected future attainment in determining current designations, we intend to expedite the redesignation of areas to attainment once they monitor clean air quality. We also intend to apply our policy which streamlines the planning process for nonattainment areas that are meeting the NAAQS but are not yet redesignated to attainment.[3]

Today's designation action is a final rule which establishes designations for all areas of the country for the PM2.5 NAAQS. In this action, we have added regulatory text to provide for the amendment of 40 CFR part 81 to identify the designation of areas across the country for the PM2.5 standard.

VIII. Has EPA Used 2004 Air Quality Data?

The final PM2.5 designations announced in today's action are based upon air quality data for calendar years 2001 through 2003. Over the course of the designations process, a number of States have provided comments to EPA suggesting that the agency should delay designations in order to permit consideration of additional air quality data from 2004 as a part of the designation decision. As discussed above, EPA must by law make the designations by December 31, 2004. This statutory deadline and the practical difficulties of obtaining complete,[4] quality assured, certified data for calendar year 2004 by December 31, 2004, have precluded EPA from using 2004 data for today's action. Under normal circumstances, we would not expect such data to be available for some time following the end of the calendar year, and under the applicable regulations States would not be required to have submitted such data until April 1, 2005, and would not be required to have certified such data until July 1, 2005. However, because we are promulgating the designations so near the end of calendar year 2004, and because complete, quality assured, certified 2004 data may become available for some areas quickly, we are interested in providing a process by which we could utilize 2004 data where possible in the designation process.

We have provided that the final PM2.5 designations announced in today's action will be effective on the date 90 days following the date of publication. If any State submits complete, quality assured, certified 2004 data to EPA by February 22, 2005, that suggest that a change of designation status is appropriate for any area within that State, and we agree that a change of designation status is appropriate, then we will withdraw the designation announced in today's action for such area and issue another designation that reflects the inclusion of 2004 data. We emphasize that we will conduct this process only for those States that submit the necessary complete, quality assured, certified data by the deadline and in those instances where we can complete the analysis and effect the change of designation status before the original effective date established by today's final action.

If inclusion of 2004 data causes an area to change from nonattainment to attainment, EPA will change the designation if every county in the area is neither monitoring a violation of the standards nor contributing to a violation of the standards in another nearby area. If inclusion of 2004 data results in nonattainment in an area that was designated attainment, we will evaluate the reasons for the violation in the area and determine the appropriate course of action, which could include redesignation of the area to nonattainment. Also, EPA commits to evaluate 2004 data for unclassifiable areas when it receives complete, quality assured, certified data from the State, which is due no later than July 2005. At that time, EPA will determine whether a change of designation for an unclassifiable area is appropriate.

IX. How Do Designations Affect Indian Country?

All counties, partial counties or Air Quality Control Regions listed in the table at the end of this document are designated as indicated, and include Indian Country geographically located within such areas, except as otherwise indicated in the table.

As mentioned earlier in this document, EPA's guidance for determining nonattainment area boundaries presumes that the CMSA or MSA monitor forms the presumptive boundary of the nonattainment areas but that the size of the area can be larger or smaller depending on contribution to the violation from nearby areas and other air quality-related technical factors. In general, and consistent with relevant air quality information, EPA intends to include Indian country encompassed within the presumptive CMSA or MSA boundaries as within the boundaries of the area for designation purposes, in order to protect public health and welfare. The EPA anticipates that in most cases, relevant air quality information will indicate that areas of Indian country located within CMSAs or MSAs should have the same designation as the surrounding area. However, based on the nine factors outlined in our guidance, there may be instances where a different designation is appropriate.

A State recommendation for a designation of an area that surrounds Indian country does not indicate the designation for Indian country. However, the conditions that support a State's designation recommendation, such as air quality data at the location of the sources, may indicate the likelihood that similar conditions exists for the Indian country located in that

[3] *See* ''Clean Data Policy for the Fine Particle National Ambient Air Quality Standards'' memorandum to Air Division Directors, Regions I–X from Steve Page, Director, Office of Air Quality Planning and Standards, December 14, 2004.

[4] Fine particle monitoring data is to be determined as ''complete'' according to data handling regulations for the PM2.5 standards in 40 CFR Part 50, Appendix N (62 FR 138, July 18, 1997).

area. States generally have neither the responsibility nor the authority for planning and regulatory activities under the CAA in Indian country.

X. Where Can I Find Information Forming the Basis for This Rule and Exchanges Between EPA, States, and Tribes Related to This Rule?

Information providing the basis for today's action and related decisions are provided in the TSD. The TSD, applicable EPA guidance memoranda, copies of correspondence regarding this process between EPA and the States, Tribes, and other parties, and EPA's responses to comments, are available for review at the EPA Docket Center listed above in the addresses section of this document and on our designation Web site at *http://www.epa.gov/oar/oaqps/particles/designations/index.htm.* State specific information is available at the EPA Regional Offices.

XI. Statutory and Executive Order Reviews

Upon promulgation of a new or revised NAAQS, the CAA requires EPA to designate areas as attaining or not attaining the NAAQS. The CAA then specifies requirements for areas based on whether such areas are attaining or not attaining the NAAQS. In this final rule, EPA assigns designations to areas as required.

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), EPA must determine whether the regulatory action is ''significant'' and, therefore, subject to OMB review and the requirements of the Executive Order. The order defines ''significant regulatory action'' as one that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities; (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is not a ''significant regulatory action'' because none of the above factors apply. As such, this final rule was not formally submitted to OMB for review.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* This rule responds to the requirement to promulgate air quality designations after promulgation of a NAAQS. This requirement is prescribed in the CAA section 107 of title 1. The present final rule does not establish any new information collection apart from that required by law. Burden means that total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in the CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedures Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For the purpose of assessing the impacts of today's final rule on small entities, small entity is defined as: (1) A small business that is a small industry entity as defined in the United States Small Business Administration (SBA) size standards (*See* 13 CFR part 121); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominate in its field.

The rule designating nonattainment areas for the PM2.5 NAAQS is not subject to RFA because it was not subject to notice and comment rulemaking requirements. *See* CAA section 107(d)(2)(B).

After considering the economic impacts of today's final rule on small entities, I certify that this rule will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal Agencies to assess the effects of their regulatory actions on State, local and Tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandate'' that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation of why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small government on compliance with regulatory requirements.

Today's final action does not include a Federal mandate within the meaning of UMRA that may result in expenditures of $100 million or more in any 1 year by either State, local, or

Tribal governments in the aggregate or to the private sector, and therefore, is not subject to the requirements of sections 202 and 205 of the UMRA. It does not create any additional requirements beyond those of the PM2.5 NAAQS (62 FR 38652; July 18, 1997), therefore, no UMRA analysis is needed. This rule establishes the application of the PM2.5 standard and the designation for each area of the country for the PM2.5 NAAQS. The CAA requires States to develop plans, including control measures, based on their designations and classifications.

One mandate that may apply as a consequence of this action to all designated nonattainment areas is the requirement under CAA section 176(c) and associated regulations to demonstrate conformity of Federal actions to State Implementation Plans (SIPs). These rules apply to Federal agencies and Metropolitan Planning Organizations (MPOs) making conformity determinations. The EPA concludes that such conformity determinations will not cost $100 million or more in the aggregate.

The EPA believes that any new controls imposed as a result of this action will not cost in the aggregate $100 million or more annually. Thus, this Federal action will not impose mandates that will require expenditures of $100 million or more in the aggregate in any 1 year.

Nonetheless, EPA carried out consultation with government entities affected by this rule, including States, Tribal governments, and local air pollution control agencies.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, or the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The CAA establishes the scheme whereby States take the lead in developing plans to meet the NAAQS. This rule will not modify the relationship of the States and EPA for purposes of developing programs to implement the NAAQS. Thus, Executive Order 13132 does not apply to this rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.'' This final rule does not have ''Tribal implications'' as specified in Executive Order 13175. This rule concerns the designation and classification of areas as attainment and nonattainment for the PM2.5 air quality standard. The CAA provides for States to develop plans to regulate emissions of air pollutants within their jurisdictions. The TAR provides Tribes the opportunity to develop and implement CAA programs such as programs to attain and maintain the PM2.5 NAAQS, but it leaves to the discretion of the Tribe the decision of whether to develop these programs and which programs, or appropriate elements of a program, the Tribe will adopt.

This final rule does not have Tribal implications as defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes, since no Tribe has implemented a CAA program to attain the PM2.5 NAAQS at this time. Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the Federal government and Indian Tribes. The CAA and the TAR establish the relationship of the Federal government and Tribes in developing plans to attain the NAAQS, and this rule does nothing to modify that relationship. Because this rule does not have Tribal implications, Executive Order 13175 does not apply.

Although Executive Order 13175 does not apply to this rule, EPA did outreach to Tribal leaders and environmental staff regarding the designations process. The EPA supports a national ''Tribal Designations and Implementation Work Group'' which provides an open forum for all Tribes to voice concerns to EPA about the designations and implementation process for the NAAQS, including the PM2.5 NAAQS. These discussions informed EPA about key Tribal concerns regarding designations as the rule was under development and gave Tribes the opportunity to express concerns about designations to EPA. Furthermore, EPA sent individualized letters to all federally recognized Tribes about EPA's intention to designate areas for the PM2.5 standard and gave Tribal leaders the opportunity for consultation.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045: ''Protection of Children From Environmental Health and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health and safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, EPA must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the EPA.

The final rule is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because EPA does not have reason to believe that the environmental health risks or safety risks addressed by this rule present a disproportionate risk or safety risk to children. Nonetheless, we have evaluated the environmental health or safety effects of the PM2.5 NAAQS on children. The results of this risk assessment are contained in the NAAQS for PM2.5, Final Rule (July 18, 1997, 62 FR 38652).

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211, ''Actions That Significantly Affect Energy Supply, Distribution, or Use,'' (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

Information on the methodology and data regarding the assessment of potential energy impacts is found in Chapter 6 of U.S. EPA 2002, Cost, Emission Reduction, Energy, and the Implementation Framework for the PM2.5 NAAQS, prepared by the Innovative Strategies and Economics Group, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 24, 2003.

I. National Technology Transfer Advancement Act (NTTAA)

Section 12(d) of the NTTAA of 1995, Public Law No. 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impracticable. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This action does not involve technical standards. Therefore, EPA did not consider the use of any VCS.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective April 5, 2005.

K. Judicial Review

Section 307 (b) (1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by EPA. This section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit (i) when the agency action consists of ''nationally applicable regulations promulgated, or final actions taken, by the Administrator,'' or (ii) when such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

This rule designating areas for the PM2.5 NAAQS is ''nationally applicable'' within the meaning of section 307(b)(1). This rule establishes designations for all areas of the United States for the PM2.5 NAAQS. At the core of this rulemaking is EPA's interpretation of the definition of nonattainment under section 107(d)(1) of the CAA. In determining which areas should be designated nonattainment (or conversely, should be designated attainment/unclassifiable), EPA used a set of nine technical factors that it applied consistently across the United States.

For the same reasons, the Administrator also is determining that the final designations are of nationwide scope and effect for the purposes of section 307(b)(1). This is particularly appropriate because in the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that an action is of ''nationwide scope or effect'' would be appropriate for any action that has ''scope or effect beyond a single judicial circuit.'' H.R. Rep. No. 95–294 at 323, 324, *reprinted* in 1977 U.S.C.C.A.N. 1402–03. Here, the scope and effect of this rulemaking extends to numerous judicial circuits since the designations apply to all areas of the country. In these circumstances, section 307(b)(1) and its legislative history calls for the Administrator to find the rule to be of ''nationwide scope or effect'' and for venue to be in the D.C. Circuit.

Thus, any petitions for review of final designations must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

List of Subjects in 40 CFR Part 81

Environmental protection, Air pollution control, National parks, Wilderness areas.

Dated: December 17, 2004.

Michael O. Leavitt,

EPA Administrator.

■ For the reasons set forth in the preamble, 40 CFR Part 81, Subpart C is amended as follows:

PART 81—DESIGNATIONS OF AREAS FOR AIR QUALITY PLANNING PURPOSES

■ 1. The authority citation for part 81 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart C—Section 107 Attainment Status Designations

■ 2. Section 81.300 is amended by revising paragraph (a) to read as follows:

§ 81.300 Scope.

(a) Attainment status designations as approved or designated by the Environmental Protection Agency (EPA) pursuant to section 107 of the CAA are listed in this subpart. Area designations are subject to revision whenever sufficient data becomes available to warrant a redesignation. Both the State and EPA can initiate changes to these designations, but any State redesignation must be submitted to EPA for concurrence. The EPA has replaced the national ambient air quality standards for particulate matter measured as total suspended particulate with standards measured as particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM–10). Accordingly, area designations for PM–10 are included in the lists in subpart C of this part. However, the TSP area designations will also remain in effect until the Administrator determines that the designations are no longer necessary for implementing the maximum allowable increases in concentrations of particulate matter pursuant to section 163(b) of the CAA, as explained in paragraph (b) of this section. The EPA has also added national ambient air quality standards for fine particulate matter measured as particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM2.5). Accordingly, area designations for PM2.5 are included in the lists in subpart C of this part.

* * * * *

■ 2a. In § 81.301, the table entitled ''Alabama—PM2.5'' is added to the end of the section to read as follows:

§ 81.301 Alabama.

* * * * *

ALABAMA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Birmingham, AL:		
Jefferson County	.....	Nonattainment.
Shelby County	.....	Nonattainment.
Walker County (part)	.....	Nonattainment.
The area described by U.S. Census 2000 block group identifiers 01–127–0214–5, 01–127–0215–4, and 01–127–0216–2		
Chattanooga, TN-GA:		
Jackson County (part)	.....	Nonattainment.
The area described by U.S. Census 2000 block block group identifier 01–071–9503–1		
Columbus, GA-AL:		
Russell County	.....	Nonattainment.
DeKalb County, AL:		
DeKalb County	.....	Unclassifiable
Gadsden, AL:		
Etowah County	.....	Unclassifiable
Rest of State:		
Autauga County	.....	Unclassifiable/Attainment.
Baldwin County	.....	Unclassifiable/Attainment.
Barbour County	.....	Unclassifiable/Attainment.
Bibb County	.....	Unclassifiable/Attainment.
Blount County	.....	Unclassifiable/Attainment.
Bullock County	.....	Unclassifiable/Attainment.
Butler County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Chambers County	.....	Unclassifiable/Attainment.
Cherokee County	.....	Unclassifiable/Attainment.
Chilton County	.....	Unclassifiable/Attainment.
Choctaw County	.....	Unclassifiable/Attainment.
Clarke County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Cleburne County	.....	Unclassifiable/Attainment.
Coffee County	.....	Unclassifiable/Attainment.
Colbert County	.....	Unclassifiable/Attainment.
Conecuh County	.....	Unclassifiable/Attainment.
Coosa County	.....	Unclassifiable/Attainment.
Covington County	.....	Unclassifiable/Attainment.
Crenshaw County	.....	Unclassifiable/Attainment.
Cullman County	.....	Unclassifiable/Attainment.
Dale County	.....	Unclassifiable/Attainment.
Dallas County	.....	Unclassifiable/Attainment.
Elmore County	.....	Unclassifiable/Attainment.
Escambia County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Geneva County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Hale County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Houston County	.....	Unclassifiable/Attainment.
Jackson County (remainder)	.....	Unclassifiable/Attainment.
Lamar County	.....	Unclassifiable/Attainment.
Lauderdale County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Limestone County	.....	Unclassifiable/Attainment.
Lowndes County	.....	Unclassifiable/Attainment.
Macon County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Marengo County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Mobile County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pickens County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Randolph County	.....	Unclassifiable/Attainment.
St. Clair County	.....	Unclassifiable/Attainment.

ALABAMA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Sumter County	.....	Unclassifiable/Attainment.
Talladega County	.....	Unclassifiable/Attainment.
Tallapoosa County	.....	Unclassifiable/Attainment.
Tuscaloosa County	.....	Unclassifiable/Attainment.
Walker County (remainder)	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wilcox County	.....	Unclassifiable/Attainment.
Winston County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 3. In § 81.302, the table entitled ''Alaska—PM2.5'' is added to the end of the section to read as follows:

§ 81.302 Alaska.

* * * * *

ALASKA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 08 Cook Inlet Intrastate:		
Anchorage Borough	.....	Unclassifiable/Attainment.
Kenai Peninsula Borough	.....	Unclassifiable/Attainment.
Matanuska-Susitna Borough	.....	Unclassifiable/Attainment.
AQCR 09 Northern Alaska Intrastate:		
Denali Borough	.....	Unclassifiable/Attainment.
Fairbanks North Star Borough	.....	Unclassifiable/Attainment.
Nome Census Area	.....	Unclassifiable/Attainment.
North Slope Borough	.....	Unclassifiable/Attainment.
Northwest Arctic Borough	.....	Unclassifiable/Attainment.
Southeast Fairbanks Census Area	.....	Unclassifiable/Attainment.
Yukon-Koyukuk Census Area	.....	Unclassifiable/Attainment.
AQCR 10 South Central Alaska Intrastate:		
Aleutians East Borough	.....	Unclassifiable/Attainment.
Aleutians West Census Area	.....	Unclassifiable/Attainment.
Bethel Census Area	.....	Unclassifiable/Attainment.
Bristol Bay Borough	.....	Unclassifiable/Attainment.
Dillingham Census Area	.....	Unclassifiable/Attainment.
Kodiak Island Borough	.....	Unclassifiable/Attainment.
Lake and Peninsula Borough	.....	Unclassifiable/Attainment.
Valdez-Cordova Census Area	.....	Unclassifiable/Attainment.
Wade Hampton Census Area	.....	Unclassifiable/Attainment.
AQCR 11 Southeastern Alaska Intrastate:		
Haines Borough	.....	Unclassifiable/Attainment.
Juneau Borough	.....	Unclassifiable/Attainment.
Ketchikan Gateway Borough	.....	Unclassifiable/Attainment.
Prince of Wales-Outer Ketchikan Census	.....	Unclassifiable/Attainment.
Sitka Borough	.....	Unclassifiable/Attainment.
Skagway-Hoonah-Angoon Census Area	.....	Unclassifiable/Attainment.
Wrangell-Petersburg Census Area	.....	Unclassifiable/Attainment.
Yakutat Borough	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 4. In § 81.303, the table entitled ''Arizona—PM2.5'' is added to the end of the section to read as follows:

§ 81.303 Arizona.

* * * * *

ARIZONA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		

ARIZONA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Apache County	.....	Unclassifiable/Attainment.
Cochise County	.....	Unclassifiable/Attainment.
Coconino County	.....	Unclassifiable/Attainment.
Gila County	.....	Unclassifiable/Attainment.
Graham County	.....	Unclassifiable/Attainment.
Greenlee County	.....	Unclassifiable/Attainment.
La Paz County	.....	Unclassifiable/Attainment.
Maricopa County	.....	Unclassifiable/Attainment.
Mohave County	.....	Unclassifiable/Attainment.
Navajo County	.....	Unclassifiable/Attainment.
Pima County	.....	Unclassifiable/Attainment.
Pinal County	.....	Unclassifiable/Attainment.
Santa Cruz County	.....	Unclassifiable/Attainment.
Yavapai County	.....	Unclassifiable/Attainment.
Yuma County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 5. In § 81.304, the table entitled ''Arizona.—PM2.5'' is added to the end of the section to read as follows:

§ 81.304 Arkansas.

* * * * *

ARKANSAS.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 016 Central Arkansas Intrastate:		
Chicot County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Cleveland County	.....	Unclassifiable/Attainment.
Conway County	.....	Unclassifiable/Attainment.
Dallas County	.....	Unclassifiable/Attainment.
Desha County	.....	Unclassifiable/Attainment.
Drew County	.....	Unclassifiable/Attainment.
Faulkner County	.....	Unclassifiable/Attainment.
Garland County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Hot Spring County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Lonoke County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pope County	.....	Unclassifiable/Attainment.
Pulaski County	.....	Unclassifiable/Attainment.
Saline County	.....	Unclassifiable/Attainment.
Yell County	.....	Unclassifiable/Attainment.
AQCR 017 Metropolitan Fort Smith Interstate:		
Benton County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Sebastian County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
AQCR 019 Monroe-El Dorado Interstate:		
Ashley County	.....	Unclassifiable/Attainment.
Bradley County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Nevada County	.....	Unclassifiable/Attainment.
Ouachita County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
AQCR 020 Northeast Arkansas Intrastate:		
Arkansas County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Craighead County	.....	Unclassifiable/Attainment.
Cross County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Independence County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.

ARKANSAS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Lee County	.....	Unclassifiable/Attainment.
Mississippi County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Phillips County	.....	Unclassifiable/Attainment.
Poinsett County	.....	Unclassifiable/Attainment.
Prairie County	.....	Unclassifiable/Attainment.
Randolph County	.....	Unclassifiable/Attainment.
St. Francis County	.....	Unclassifiable/Attainment.
Sharp County	.....	Unclassifiable/Attainment.
White County	.....	Unclassifiable/Attainment.
Woodruff County	.....	Unclassifiable/Attainment.
AQCR 021 Northwest Arkansas Intrastate:		
Baxter County	.....	Unclassifiable/Attainment.
Boone County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Cleburne County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Fulton County	.....	Unclassifiable/Attainment.
Izard County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Newton County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Searcy County	.....	Unclassifiable/Attainment.
Stone County	.....	Unclassifiable/Attainment.
Van Buren County	.....	Unclassifiable/Attainment.
AQCR 022 Shreveport-Texarkana-Tyler Interstate:		
Columbia County	.....	Unclassifiable/Attainment.
Hempstead County	.....	Unclassifiable/Attainment.
Howard County	.....	Unclassifiable/Attainment.
Lafayette County	.....	Unclassifiable/Attainment.
Little River County	.....	Unclassifiable/Attainment.
Miller County	.....	Unclassifiable/Attainment.
Sevier County	.....	Unclassifiable/Attainment.
Memphis, TN–AR:		
(AQCR 018 Metropolitan Memphis Interstate):		
Crittenden County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 6. In § 81.305, the table entitled ''California.—PM2.5'' is added to the end of the section to read as follows:

CALIFORNIA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Los Angeles-South Coast Air Basin, CA:		
Los Angeles County (part)	.....	Nonattainment.

CALIFORNIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
That portion of Los Angeles County which lies south and west of a line described as follows: Beginning at the Los Angeles-San Bernardino County boundary and running west along the Township line common to Township 3 North and Township 2 North, San Bernardino Base and Meridian; then north along the range line common to Range 8 West and Range 9 West; then west along the Township line common to Township 4 North and Township 3 North; then north along the range line common to Range 12 West and Range 13 West to the southeast corner of Section 12, Township 5 North and Range 13 West; then west along the south boundaries of Sections 12, 11, 10, 9, 8, and 7, Township 5 North and Range 13 West to the boundary of the Angeles National Forest which is collinear with the range line common to Range 13 West and Range 14 West; then north and west along the Angeles National Forest boundary to the point of intersection with the Township line common to Township 7 North and Township 6 North (point is at the northwest corner of Section 4 in Township 6 North and Range 14 West); then west along the Township line common to Township 7 North and Township 6 North; then north along the range line common to Range 15 West and Range 16 West to the southeast corner of Section 13, Township 7 North and Range 16 West; then along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 7 North and Range 16 West; then north along the range line common to Range 16 West and Range 17 West to the north boundary of the Angeles National Forest (collinear with the Township line common to Township 8 North and Township 7 North); then west and north along the Angeles National Forest boundary to the point of intersection with the south boundary of the Rancho La Liebre Land Grant; then west and north along this land grant boundary to the Los Angeles-Kern County boundary.		
Orange County	.....	Nonattainment.
Riverside County (part)	.....	Nonattainment.
That portion of Riverside County which lies to the west of a line described as follows: Beginning at the Riverside-San Diego County boundary and running north along the range line common to Range 4 East and Range 3 East, San Bernardino Base and Meridian; then east along the Township line common to Township 8 South and Township 7 South; then north along the range line common to Range 5 East and Range 4 East; then west along the Township line common to Township 6 South and Township 7 South to the southwest corner of Section 34, Township 6 South, Range 4 East; then north along the west boundaries of Sections 34, 27, 22, 15, 10, and 3, Township 6 South, Range 4 East; then west along the Township line common to Township 5 South and Township 6 South; then north along the range line common to Range 4 East and Range 3 East; then west along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 5 South, Range 3 East; then north along the range line common to Range 2 East and Range 3 East; to the Riverside-San Bernardino County line.		
San Bernardino County (part)	.....	Nonattainment.
That portion of San Bernardino County which lies south and west of a line described as follows: Beginning at the San Bernardino-Riverside County boundary and running north along the range line common to Range 3 East and Range 2 East, San Bernardino Base and Meridian; then west along the Township line common to Township 3 North and Township 2 North to the San Bernardino-Los Angeles County boundary.		
San Diego, CA:		
San Diego County (part)	.....	Nonattainment.
That portion of San Diego County that excludes the areas listed below: La Posta Areas #1 and #2, Cuyapaipe Area, Manzanita Area, Campo Areas #1 and #2[b].		
San Joaquin Valley, CA:		
Fresno County	.....	Nonattainment.
Kern County (part)	.....	Nonattainment.
That portion of Kern County which lies west and north of a line described as follows: Beginning at the Kern-Los Angeles County boundary and running north and east along the northwest boundary of the Rancho La Libre Land Grant to the point of intersection with the range line common to R. 16 W. and R. 17 W., San Bernardino Base and Meridian; north along the range line to the point of intersection with the Rancho El Tejon Land Grant boundary; then southeast, northeast, and northwest along the boundary of the Rancho El Tejon Land Grant to the northwest corner of S. 3, T. 11 N., R. 17 W.; then west 1.2 miles; then north to the Rancho El Tejon Land Grant boundary; then northwest along the Rancho El Tejon line to the southeast corner of S. 34, T. 32 S., R. 30 E., Mount Diablo Base and Meridian; then north to the northwest corner of S. 35, T. 31 S., R. 30 E.; then northeast along the boundary of the Rancho El Tejon Land Grant to the southwest corner of S. 18, T. 31 S., R. 31 E.; then east to the southeast corner of S. 13, T. 31 S., R. 31 E.; then north along the range line common to R. 31 E. and R. 32 E., Mount Diablo Base and Meridian, to the northwest corner of S. 6, T. 29 S., R. 32 E.; then east to the southwest corner of S. 31, T. 28 S., R. 32 E.; then north along the range line common to R. 31 E. and R. 32 E. to the northwest corner of S. 6, T. 28 S., R. 32 E., then west to the southeast corner of S. 36, T. 27 S., R. 31 E., then north along the range line common to R. 31 E. and R. 32 E. to the Kern-Tulare County boundary.		
Kings County	.....	Nonattainment.

CALIFORNIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Madera County	.....	Nonattainment.
Merced County	.....	Nonattainment.
San Joaquin County	.....	Nonattainment.
Stanislaus County	.....	Nonattainment.
Tulare County	.....	Nonattainment.
North Coast Air Basin:		
Del Norte County	.....	Unclassifiable/Attainment.
Humboldt County	.....	Unclassifiable/Attainment.
Mendocino County	.....	Unclassifiable/Attainment.
Sonoma County (part)	.....	Unclassifiable/Attainment.
That portion of Sonoma county which lies north and west of a line described as follows: Beginning at the south-easterly corner of the Rancho Estero Americano, being on the boundary line between Marin and Sonoma Counties, California; thence running northerly along the easterly boundary line of said Rancho Estero Americano to the northeasterly corner thereof, being an angle corner in the westerly boundary line of Rancho Canada de Jonive, thence running along said boundary of Rancho Canada de Jonive westerly; northerly and easterly to its intersection with the easterly line of Graton Road; thence running along the easterly and southerly line of Graton Road northerly and easterly to its intersection with the easterly line of Sullivan Road; thence running northerly along said easterly line of Sullivan Road to the southerly line of Green Valley Road; thence running easterly along the said southerly line of Green Valley Road and easterly along the southerly line of State Highway 116, to the westerly and northerly line of Vine Hill Road; thence running along the westerly and northerly line of Vine Hill Road, northerly and easterly to its intersection with the westerly line of Laguna Road; thence running northerly along the westerly line of Laguna Road and the northerly projection thereof to the northerly line of Trenton Road; thence running westerly along the northerly line of said Trenton Road to the easterly line of Trenton-Healdsburg Road to the easterly line of Eastside Road: thence running northerly along said easterly line of Eastside Road to its intersection with the southerly line of Rancho Sotoyome; thence running easterly along said southerly line of Rancho Sotoyome to its intersection with the Township line common to Townships 8 and 9 north, Mt. Diablo Base and Meridian; thence running easterly along said Township line to its intersection with the boundary line between Sonoma and Napa Counties, State of California.		
Trinity County	.....	Unclassifiable/Attainment.
Northeast Plateau Air Basin:		
Lassen County	.....	Unclassifiable/Attainment.
Modoc County	.....	Unclassifiable/Attainment.
Siskiyou County	.....	Unclassifiable/Attainment.
Lake County Air Basin:		
Lake County	.....	Unclassifiable/Attainment.
Upper Sacramento Valley Region:		
Butte County	.....	Unclassifiable/Attainment.
Colusa County	.....	Unclassifiable/Attainment.
Glenn County	.....	Unclassifiable/Attainment.
Shasta County	.....	Unclassifiable/Attainment.
Sutter County (part)	.....	Unclassifiable/Attainment.
All portions of the county except that portion south of a line connecting the northern border of Yolo County to the southwest tip of Yuba County and continuing along the southern Yuba County border to Placer County.		
Tehama County	.....	Unclassifiable/Attainment.
Yuba County	.....	Unclassifiable/Attainment.
Sacramento Metropolitan Region:		
El Dorado County (part)	.....	Unclassifiable/Attainment.
All portions of the county except that portion of El Dorado County within the drainage area naturally tributary to Lake Tahoe including said Lake.		
Placer County (part)	.....	Unclassifiable/Attainment.
All portions of the county except that portion of Placer County within the drainage area naturally tributary to Lake Tahoe including said Lake, plus that area in the vicinity of the head of the Truckee River described as follows: Commencing at the point common to the aforementioned drainage area crestline and the line common to Townships 15 North and 16 North, Mount Diablo Base and Meridian, and following that line in a westerly direction to the northwest corner of Section 3, Township 15 North, Range 16 East, Mount Diablo Base and Meridian, thence south along the west line of Sections 3 and 10, Township 15 North, Range 16 East, Mount Diablo Base and Meridian, to the intersection with the said drainage area crestline, thence following the said drainage area boundary in a southeasterly, then northeasterly direction to and along the Lake Tahoe Dam, thence following the said drainage area crestline in a northeasterly, then northwesterly direction to the point of beginning.		
Sacramento County	.....	Unclassifiable/Attainment.
Solano County (part)	.....	Unclassifiable/Attainment.

CALIFORNIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
That portion of Solano County which lies north and east of a line described as follows: Beginning at the intersection of the westerly boundary of Solano County and the 1/4 section line running east and west through the center of Section 34; Township 6 North, Range 2 West, Mount Diablo Base and Meridian, thence east along said 1/4 section line to the east boundary of Section 36, Township 6 North, Range 2 West, thence south 1/2 mile and east 2.0 miles, more or less, along the west and south boundary of Los Putos Rancho to the northwest corner of Section 4, Township 5 North, Range 1 West, thence east along a line common to Township 5 North and Township 6 North to the northeast corner of Section 3, Township 5 North, Range 1 East, thence south along section lines to the southeast corner of Section 10, Township 3 North, Range 1 East, thence east along section lines to the south 1/4 corner of Section 8, Township 3 North, Range 2 East, thence east to the boundary between Solano and Sacramento Counties.		
Sutter County (part)	.....	Unclassifiable/Attainmant
That portion south of a line connecting the northern border of Yolo County to the southwest tip of Yuba County and continuing along the southern Yuba County border to Placer County.		
Yolo County	.....	Unclassifiable/Attainment.
Northern Mountain Counties:		
Nevada County	.....	Unclassifiable/Attainment.
Plumas County	.....	Unclassifiable/Attainment.
Sierra County	.....	Unclassifiable/Attainment.
Central Mountain Counties:		
Amador County	.....	Unclassifiable/Attainment.
Calaveras County	.....	Unclassifiable/Attainment.
Southern Mountain Counties:		
Mariposa County	.....	Unclassifiable/Attainment.
Tuolumne County	.....	Unclassifiable/Attainment.
Lake Tahoe Air Basin:		
El Dorado County (part)	.....	Unclassifiable/Attainmant
That portion of El Dorado County within the drainage area naturally tributary to Lake Tahoe including said Lake.		
Placer County (part)	.....	Unclassifiable/Attainment.
That portion of Placer County within the Attainment. drainage area naturally tributary to Lake Tahoe including said Lake, plus that area in the vicinity of the head of the Truckee River described as follows: Commencing at the point common to the aforementioned drainage area crestline and the line common to Townships 15 North and 16 North, Mount Diablo Base and Meridian, and following that line in a westerly direction to the northwest corner of Section 3, Township 15 North, Range 16 East, Mount Diablo Base and Meridian, thence south along the west line of Sections 3 and 10, Township 15 North, Range 16 East, Mount Diablo Base and Meridian, to the intersection with the said drainage area crestline, thence following the said drainage area boundary in a southeasterly, then northeasterly direction to and along the Lake Tahoe Dam, thence following the said drainage area crestline in a northeasterly, then northwesterly direction to the point of beginning.	.....	Attainment.
San Francisco Bay Area Air Basin:		
Alameda County	.....	Unclassifiable/Attainment.
Contra Costa County	.....	Unclassifiable/Attainment.
Marin County	.....	Unclassifiable/Attainment.
Napa County	.....	Unclassifiable/Attainment.
San Francisco County	.....	Unclassifiable/Attainment.
San Mateo County	.....	Unclassifiable/Attainment.
Santa Clara County	.....	Unclassifiable/Attainment.
Solano County (part)	.....	Unclassifiable/Attainment.
Portion of Solano County which lies south and west of a line described as follows: Beginning at the intersection of the westerly boundary of Solano County and the ¼ section line running east and west through the center of Section 34, T6N, R2W, M.D.B. & M., thence east along said ¼ section line to the east boundary of Section 36, T6N, R2W, thence south ½ mile and east 2.0 miles, more or less, along the west and south boundary of Los Putos Rancho to the northwest corner of Section 4, T5N, R1W, thence east along a line common to T5N and T6N to the northeast corner of Section 3, T5N, R1E, thence south along section lines to the southeast corner of Section 10, T3N, R1E, thence east along section lines to the south ¼ corner of Section 8, T3N, R2E, thence east to the boundary between Solano and Sacramento Counties.		
Sonoma County (part)	.....	Unclassifiable/Attainment.

CALIFORNIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
That portion of Sonoma County which lies south and east of a line described as follows: Beginning at the southeasterly corner of the Rancho Estero Americano, being on the boundary line between Marin and Sonoma Counties, California; thence running northerly along the easterly boundary line of said Rancho Estero Americano to the northeasterly corner thereof, being an angle corner in the westerly boundary line of Rancho Canada de Jonive; thence running along said boundary of Rancho Canada de Jonive westerly, northerly and easterly to its intersection with the easterly line of Graton Road; thence running along the easterly and southerly line of Graton Road, northerly and easterly to its intersection with the easterly line of Sullivan Road; thence running northerly along said easterly line of Sullivan Road to the southerly line of Green Valley Road; thence running easterly along the said southerly line of Green Valley Road and easterly along the southerly line of State Highway 116, to the westerly line of Vine Hill Road; thence running along the westerly and northerly line of Vine Hill Road, northerly and easterly to its intersection with the westerly line of Laguna Road; thence running northerly along the westerly line of Laguna Road and the northerly projection thereof to the northerly line of Trenton Road; thence running westerly along the northerly line of said Trenton Road to the easterly line of Trenton-Healdsburg Road; thence running northerly along said easterly line of Trenton-Healdsburg Road to the easterly line of Eastside Road; thence running northerly along said easterly line of Eastside Road to its intersection with the southerly line of Rancho Sotoyome; thence running easterly along said southerly line of Rancho Sotoyome to its intersection with the Township line common to Townships 8 and 9 North, M.D.M.; thence running easterly along said township line to its intersection with the boundary line between Sonoma and Napa Counties.		
North Central Coast Air Basin:		
Monterey County	.....	Unclassifiable/Attainment.
San Benito County	.....	Unclassifiable/Attainment.
Santa Cruz County	.....	Unclassifiable/Attainment.
San Luis Obispo County:		
San Luis Obispo County	.....	Unclassifiable/Attainment.
Santa Barbara County:		
Santa Barbara County (part)	.....	Unclassifiable/Attainment.
Excluding Channel Islands		
Ventura County:		
Ventura County (part)	.....	Unclassifiable/Attainment.
Excluding Anacapa and San Nicolas Islands.		
Northern Channel Islands:		
Santa Barbara County (part)	.....	Unclassifiable/Attainment.
The islands located in the South Central Coast Air Basin, including San Miguel, Santa Rosa, Santa Cruz, and San Nicolas.		
Ventura County (part)	.....	Unclassifiable/Attainment.
Anacapa and San Nicolas Islands.		
Great Basin Valleys Air Basin:		
Alpine County	.....	Unclassifiable/Attainment.
Inyo County (part)	.....	Unclassifiable/Attainment.
That portion of Inyo County that lies outside Hydrologic Unit Number 18090205.		
Mono County	.....	Unclassifiable/Attainment.
Coso Junction:		
Inyo County (part)	.....	Unclassifiable/Attainment.
That portion of Inyo County that lies inside Hydrologic Unit Number 18090205.		
Eastern Kern County:		
Kern County (part)	.....	Unclassifiable/Attainment.

CALIFORNIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
That portion of Kern County (with the exception of that portion in Hydrologic Unit Number 18090205 —the Indian Wells Valley) east and south of a line described as follows: Beginning at the Kern—Los Angeles County boundary and running north and east along the northwest boundary of the Rancho La Liebre Land Grant to the point of intersection with the range line common to Range 16 West and Range 17 West, San Bernardino Base and Meridian; north along the range line to the point of intersection with the Rancho El Tejon Land Grant boundary; then southeast, northeast, and northwest along the boundary of the Rancho El Tejon Grant to the northwest corner of Section 3, Township 11 North, Range 17 West; then west 1.2 miles; then north to the Rancho El Tejon Land Grant boundary; then northwest along the Rancho El Tejon line to the southeast corner of Section 34, Township 32 South, Range 30 East, Mount Diablo Base and Meridian; then north to the northwest corner of Section 35, Township 31 South, Range 30 East; then northeast along the boundary of the Rancho El Tejon Land Grant to the southwest corner of Section 18, Township 31 South, Range 31 East; then east to the southeast corner of Section 13, Township 31 South, Range 31 East; then north along the range line common to Range 31 East and Range 32 East, Mount Diablo Base and Meridian, to the northwest corner of Section 6, Township 29 South, Range 32 East; then east to the southwest corner of Section 31, Township 28 South, Range 32 East; then north along the range line common to Range 31 East and Range 32 East to the northwest corner of Section 6, Township 28 South, Range 32 East, then west to the southeast corner of Section 36, Township 27 South, Range 31 East, then north along the range line common to Range 31 East and Range 32 East to the Kern-Tulare County boundary.		
Indian Wells Valley:		
Kern County (part)	.....	Unclassifiable/Attainment.
That portion of Kern County that lies inside Hydrologic Unit Number 18090205.		
Western Mojave Desert and Antelope Valley:		
Los Angeles County (part)	.....	Unclassifiable
That portion of Los Angeles County which lies north and east of a line described as follows: Beginning at the Los Angeles—San Bernardino County boundary and running west along the Township line common to Township 3 North and Township 2 North, San Bernardino Base and Meridian; then north along the range line common to Range 8 West and Range 9 West; then west along the Township line common to Township 4 North and Township 3 North; then north along the range line common to Range 12 West and Range 13 West to the southeast corner of Section 12, Township 5 North and Range 13 West; then west along the south boundaries of Sections 12, 11, 10, 9, 8, and 7, Township 5 North and Range 13 West to the boundary of the Angeles National Forest which is collinear with the range line common to Range 13 West and Range 14 West; then north and west along the Angeles National Forest boundary to the point of intersection with the Township line common to Township 7 North and Township 6 North (point is at the northwest corner of Section 4 in Township 6 North and Range 14 West); then west along the Township line common to Township 7 North and Township 6 North; then north along the range line common to Range 15 West and Range 16 West to the southeast corner of Section 13, Township 7 North and Range 16 West; then along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 7 North and Range 16 West; then north along the range line common to Range 16 West and Range 17 West to the north boundary of the Angeles National Forest (collinear with the Township line common to Township 8 North and Township 7 North); then west and north along the Angeles National Forest boundary to the point of intersection with the south boundary of the Rancho La Liebre Land Grant; then west and north along this land grant boundary to the Los Angeles-Kern County boundary.		
San Bernardino County (part)	.....	Unclassifiable/Attainment.
That portion of San Bernardino County (with the exception of that portion in Hydrologic Unit Number 18090205) which lies north and east of a line described as follows: Beginning at the San Bernardino—Riverside County boundary and running north along the range line common to Range 3 East and Range 2 East, San Bernardino Base and Meridian; then west along the Township line common to Township 3 North and Township 2 North to the San Bernardino—Los Angeles County boundary; And that portion of San Bernardino County which lies south and west of a line described as follows: latitude 35 degrees, 10 minutes north and longitude 115 degrees, 45 minutes west.		
Trona:		
San Bernardino County (part)	.....	Unclassifiable/Attainment.
That portion of San Bernardino County that lies inside Hydrologic Unit Number 18090205.		
Coachella Valley:		
Riverside County (part)	.....	Unclassifiable/Attainment.

CALIFORNIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
That portion of Riverside County which lies to the east of a line described as follows: Beginning at the Riverside—San Diego County boundary and running north along the range line common to Range 4 East and Range 3 East, San Bernardino Base and Meridian; then east along the Township line common to Township 8 South and Township 7 South; then north along the range line common to Range 5 East and Range 4 East; then west along the Township line common to Township 6 South and Township 7 South to the southwest corner of Section 34, Township 6 South, Range 4 East; then north along the west boundaries of Sections 34, 27, 22, 15, 10, and 3, Township 6 South, Range 4 East; then west along the Township line common to Township 5 South and Township 6 South; then north along the range line common to Range 4 East and Range 3 East; then west along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 5 South, Range 3 East; then north along the range line common to Range 2 East and Range 3 East;, to the Riverside-San Bernardino County line: And that portion of Riverside County which lies to the west of a line described as follows: That segment of the southwestern boundary line of Hydrologic Unit Number 18100100 within Riverside County, further described as follows: Beginning at the Riverside-Imperial County boundary and running north along the range line common to Range 17 East and Range 16 East, San Bernardino Base and Meridian; then northwest along the ridge line of the Chuckwalla Mountains, through Township 8 South, Range 16 East and Township 7 South, Range 16 East, until the Black Butte Mountain, elevation 4504'; then west and northwest along the ridge line to the southwest corner of Township 5 South, Range 14 East; then north along the range line common to Range 14 East and Range 13 East; then west and northwest along the ridge line to Monument Mountain, elevation 4834'; then southwest and then northwest along the ridge line of the Little San Bernardino Mountains to Quail Mountain, elev. 5814'; then northwest along the ridge line to the Riverside-San Bernardino County line.		
Far Eastern Riverside and San Bernardino Counties:		
San Bernardino County (remainder)	.....	Unclassifiable/Attainment.
Riverside County (remainder)	.....	Unclassifiable/Attainment.
Imperial County:		
Imperial County	.....	Unclassifiable/Attainment.
San Diego County Tribal Area:		
San Diego County (part).		
La Posta Areas #1 and #2[b]	.....	Unclassifiable/Attainment.
Cuyapaipe Area[b]	.....	Unclassifiable/Attainment.
Manzanita Area[b]	.....	Unclassifiable/Attainment.
Campo Areas #1 and #2[b]	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.
[b] The boundaries for these designated areas are based on coordinates of latitude and longitude derived from EPA Region 9's GIS database and are illustrated in a map entitled ''Southeastern San Diego County Unclassifiable/Attainment. Areas for the PM–2.5 NAAQS,'' dated December 10, 2004, including an attached set of coordinates. The map and attached set of coordinates are available at EPA's Region 9 Air Division office. The designated areas roughly approximate the boundaries of the reservations for these tribes, but their inclusion in this table is intended for the CAA planning purposes only and is not intended to be a federal determination of the exact boundaries of the reservations. Also, the specific listing of these areas in this table does not confer, deny, or withdraw Federal recognition of any of the tribes so listed nor any of the tribes not listed.

■ 7. In § 81.306, the table entitled ''Colorado—PM2.5'' is added to the end of the section to read as follows:

§ 81.306 Colorado.

* * * * *

COLORADO.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Denver-Boulder Area:		
Adams County (part)	.....	Unclassifiable/Attainment.
West of Kiowa Creek		
Arapahoe County (part)	.....	Unclassifiable/Attainment.
West of Kiowa Creek		
Boulder County (part)	.....	Unclassifiable/Attainment.
Excluding Rocky Mountain National Park		
Broomfield County	.....	Unclassifiable/Attainment.
Denver County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
State AQCR 01:		

COLORADO.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Logan County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Phillips County	.....	Unclassifiable/Attainment.
Sedgwick County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Yuma County	.....	Unclassifiable/Attainment.
State AQCR 02:		
Larimer County	.....	Unclassifiable/Attainment.
Weld County	.....	Unclassifiable/Attainment.
State AQCR 03 (remainder of):		
Adams County (remainder)	.....	Unclassifiable/Attainment.
Arapahoe County (remainder)	.....	Unclassifiable/Attainment.
Boulder County (remainder)	.....	Unclassifiable/Attainment.
Clear Creek County	.....	Unclassifiable/Attainment.
Gilpin County	.....	Unclassifiable/Attainment.
State AQCR 04:		
El Paso County	.....	Unclassifiable/Attainment.
Park County	.....	Unclassifiable/Attainment.
Teller County	.....	Unclassifiable/Attainment.
State AQCR 05:		
Cheyenne County	.....	Unclassifiable/Attainment.
Elbert County	.....	Unclassifiable/Attainment.
Kit Carson County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
State AQCR 06:		
Baca County	.....	Unclassifiable/Attainment.
Bent County	.....	Unclassifiable/Attainment.
Crowley County	.....	Unclassifiable/Attainment.
Kiowa County	.....	Unclassifiable/Attainment.
Otero County	.....	Unclassifiable/Attainment.
Prowers County	.....	Unclassifiable/Attainment.
State AQCR 07:		
Huerfano County	.....	Unclassifiable/Attainment.
Las Animas County	.....	Unclassifiable/Attainment.
Pueblo County	.....	Unclassifiable/Attainment.
State AQCR 08:		
Alamosa County	.....	Unclassifiable/Attainment.
Conejos County	.....	Unclassifiable/Attainment.
Costilla County	.....	Unclassifiable/Attainment.
Mineral County	.....	Unclassifiable/Attainment.
Rio Grande County	.....	Unclassifiable/Attainment.
Saguache County	.....	Unclassifiable/Attainment.
State AQCR 09:		
Archuleta County	.....	Unclassifiable/Attainment.
Dolores County	.....	Unclassifiable/Attainment.
La Plata County	.....	Unclassifiable/Attainment.
Montezuma County	.....	Unclassifiable/Attainment.
San Juan County	.....	Unclassifiable/Attainment.
State AQCR 10:		
Delta County	.....	Unclassifiable/Attainment.
Gunnison County	.....	Unclassifiable/Attainment.
Hinsdale County	.....	Unclassifiable/Attainment.
Montrose County	.....	Unclassifiable/Attainment.
Ouray County	.....	Unclassifiable/Attainment.
San Miguel County	.....	Unclassifiable/Attainment.
State AQCR 11:		
Garfield County	.....	Unclassifiable/Attainment.
Mesa County	.....	Unclassifiable/Attainment.
Moffat County	.....	Unclassifiable/Attainment.
Rio Blanco County	.....	Unclassifiable/Attainment.
State AQCR 12:		
Eagle County	.....	Unclassifiable/Attainment.
Grand County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Pitkin County	.....	Unclassifiable/Attainment.
Routt County	.....	Unclassifiable/Attainment.
Summit County	.....	Unclassifiable/Attainment.
State AQCR 13:		
Chaffee County	.....	Unclassifiable/Attainment.
Custer County	.....	Unclassifiable/Attainment.

COLORADO.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Fremont County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 8. In § 81.307, the table entitled ''Connecticut.—PM2.5'' is added to the end of the section to read as follows:

§ 81.307 Connecticut.

* * * * *

CONNECTICUT.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
New York-N. New Jersey-Long Island, NY-NJ-CT:		
Fairfield County	.....	Nonattainment.
New Haven County	.....	Nonattainment.
Rest of State:		
Hartford County	.....	Unclassifiable/Attainment.
Litchfield County	.....	Unclassifiable/Attainment.
Middlesex County	.....	Unclassifiable/Attainment.
New London County	.....	Unclassifiable/Attainment.
Tolland County	.....	Unclassifiable/Attainment.
Windham County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 9. In § 81.308, the table entitled ''Delaware.—PM2.5'' is added to the end of the section to read as follows:

§ 81.308 Delaware.

* * * * *

DELAWARE.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Philadelphia-Wilmington, PA–NJ–DE:		
New Castle County	.....	Nonattainment.
Southern Delaware Intrastate AQCR:		
Kent County	.....	Unclassifiable/Attainment.
Sussex County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 10. In § 81.309, the table entitled ''District of Columbia.—PM2.5'' is added to the end of the section to read as follows:

§ 81.309 District of Columbia.

* * * * *

DISTRICT OF COLUMBIA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Washington, DC-MD-VA:		
District of Columbia	.....	Nonattainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 11. In § 81.310, the table entitled ''Florida.—PM2.5'' is added to the end of the section to read as follows:

§ 81.310 Florida.

* * * * *

FLORIDA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Alachua County	.....	Unclassifiable/Attainment.
Baker County	.....	Unclassifiable/Attainment.
Bay County	.....	Unclassifiable/Attainment.
Bradford County	.....	Unclassifiable/Attainment.
Brevard County	.....	Unclassifiable/Attainment.
Broward County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Charlotte County	.....	Unclassifiable/Attainment.
Citrus County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Collier County	.....	Unclassifiable/Attainment.
Columbia County	.....	Unclassifiable/Attainment.
DeSoto County	.....	Unclassifiable/Attainment.
Dixie County	.....	Unclassifiable/Attainment.
Duval County	.....	Unclassifiable/Attainment.
Escambia County	.....	Unclassifiable/Attainment.
Flagler County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Gadsden County	.....	Unclassifiable/Attainment.
Gilchrist County	.....	Unclassifiable/Attainment.
Glades County	.....	Unclassifiable/Attainment.
Gulf County	.....	Unclassifiable/Attainment.
Hamilton County	.....	Unclassifiable/Attainment.
Hardee County	.....	Unclassifiable/Attainment.
Hendry County	.....	Unclassifiable/Attainment.
Hernando County	.....	Unclassifiable/Attainment.
Highlands County	.....	Unclassifiable/Attainment.
Hillsborough County	.....	Unclassifiable/Attainment.
Holmes County	.....	Unclassifiable/Attainment.
Indian River County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Lafayette County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Leon County	.....	Unclassifiable/Attainment.
Levy County	.....	Unclassifiable/Attainment.
Liberty County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Manatee County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Martin County	.....	Unclassifiable/Attainment.
Miami-Dade County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Nassau County	.....	Unclassifiable/Attainment.
Okaloosa County	.....	Unclassifiable/Attainment.
Okeechobee County	.....	Unclassifiable/Attainment.
Orange County	.....	Unclassifiable/Attainment.
Osceola County	.....	Unclassifiable/Attainment.
Palm Beach County	.....	Unclassifiable/Attainment.
Pasco County	.....	Unclassifiable/Attainment.
Pinellas County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Putnam County	.....	Unclassifiable/Attainment.
St. Johns County	.....	Unclassifiable/Attainment.
St. Lucie County	.....	Unclassifiable/Attainment.
Santa Rosa County	.....	Unclassifiable/Attainment.
Sarasota County	.....	Unclassifiable/Attainment.
Seminole County	.....	Unclassifiable/Attainment.
Sumter County	.....	Unclassifiable/Attainment.
Suwannee County	.....	Unclassifiable/Attainment.
Taylor County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Volusia County	.....	Unclassifiable/Attainment.
Wakulla County	.....	Unclassifiable/Attainment.
Walton County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 12. In § 81.311, the table entitled ''Georgia.—PM2.5'' is added to the end of the section to read as follows:

§ 81.311 Georgia.

* * * * *

GEORGIA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Athens, GA:		
Clarke County	.....	Nonattainment.
Atlanta, GA:		
Barrow County	.....	Nonattainment.
Bartow County	.....	Nonattainment.
Carroll County	.....	Nonattainment.
Cherokee County	.....	Nonattainment.
Clayton County	.....	Nonattainment.
Cobb County	.....	Nonattainment.
Coweta County	.....	Nonattainment.
DeKalb County	.....	Nonattainment.
Douglas County	.....	Nonattainment.
Fayette County	.....	Nonattainment.
Forsyth County	.....	Nonattainment.
Fulton County	.....	Nonattainment.
Gwinnett County	.....	Nonattainment.
Hall County	.....	Nonattainment.
Heard County (part)	.....	Nonattainment.
The northeast portion that extends north of 33 degrees 24 minutes (north) to the Carroll County border and east of 85 degrees 3 minutes (west) to the Coweta County border.		
Henry County	.....	Nonattainment.
Newton County	.....	Nonattainment.
Paulding County	.....	Nonattainment.
Putnam County (part)	.....	Nonattainment.
The area described by U.S. Census 2000 block group identifier 13–237–9603–1.		
Rockdale County	.....	Nonattainment.
Spalding County	.....	Nonattainment.
Walton County	.....	Nonattainment.
Chattanooga, TN–GA:		
Catoosa County	.....	Nonattainment.
Walker County	.....	Nonattainment.
Columbus, GA–AL:		
Muscogee County	.....	Nonattainment.
Rome, GA:		
Floyd County	.....	Nonattainment.
Macon, GA:		
Bibb County	.....	Nonattainment.
Monroe County (part)	.....	Nonattainment.
From the point where Bibb and Monroe Counties meet at U.S. Hwy 23/Georgia Hwy 98 follow the Bibb/Monroe County line westward 150′ from the U.S. Hwy 23/Georgia Hwy 87 centerline, proceed northward 150′ west of and parallel to the U.S. Hwy 23/Georgia Hwy 87 centerline to 33 degrees, 04 minutes, 30 seconds; proceeed westward to 83 degrees, 49 minutes, 45 seconds; proceed due south to 150′ north of the Georgia Hwy 18 centerline, proceed eastward 150′ north of and parallel to the Georgia Hwy 18 centerline to 1150′ west of the U.S. Hwy 23/ Georgia Hwy 87 centerline, proceed southward 1150′ west of and parallel to the U.S. Hwy 23/Georgia Hwy 87 centerline to the Monroe/Bibb County line; then follow the Monroe/Bibb County line to 150′ west of the U.S. Hwy 23/ Georgia Hwy 87 centerline.		
Rest of State:		
Appling County	.....	Unclassifiable/Attainment.
Atkinson County	.....	Unclassifiable/Attainment.
Bacon County	.....	Unclassifiable/Attainment.
Baker County	.....	Unclassifiable/Attainment.
Baldwin County	.....	Unclassifiable/Attainment.
Banks County	.....	Unclassifiable/Attainment.
Ben Hill County	.....	Unclassifiable/Attainment.
Berrien County	.....	Unclassifiable/Attainment.
Bleckley County	.....	Unclassifiable/Attainment.
Brantley County	.....	Unclassifiable/Attainment.
Brooks County	.....	Unclassifiable/Attainment.
Bryan County	.....	Unclassifiable/Attainment.
Bulloch County	.....	Unclassifiable/Attainment.
Burke County	.....	Unclassifiable/Attainment.
Butts County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Camden County	.....	Unclassifiable/Attainment.

GEORGIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Candler County	.....	Unclassifiable/Attainment.
Charlton County	.....	Unclassifiable/Attainment.
Chatham County	.....	Unclassifiable/Attainment.
Chattahoochee County	.....	Unclassifiable/Attainment.
Chattooga County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Clinch County	.....	Unclassifiable/Attainment.
Coffee County	.....	Unclassifiable/Attainment.
Colquitt County	.....	Unclassifiable/Attainment.
Columbia County	.....	Unclassifiable/Attainment.
Cook County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Crisp County	.....	Unclassifiable/Attainment.
Dade County	.....	Unclassifiable/Attainment.
Dawson County	.....	Unclassifiable/Attainment.
Decatur County	.....	Unclassifiable/Attainment.
Dodge County	.....	Unclassifiable/Attainment.
Dooly County	.....	Unclassifiable/Attainment.
Dougherty County	.....	Unclassifiable/Attainment.
Early County	.....	Unclassifiable/Attainment.
Echols County	.....	Unclassifiable/Attainment.
Effingham County	.....	Unclassifiable/Attainment.
Elbert County	.....	Unclassifiable/Attainment.
Emanuel County	.....	Unclassifiable/Attainment.
Evans County	.....	Unclassifiable/Attainment.
Fannin County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Gilmer County	.....	Unclassifiable/Attainment.
Glascock County	.....	Unclassifiable/Attainment.
Glynn County	.....	Unclassifiable/Attainment.
Gordon County	.....	Unclassifiable/Attainment.
Grady County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Habersham County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Haralson County	.....	Unclassifiable/Attainment.
Harris County	.....	Unclassifiable/Attainment.
Hart County	.....	Unclassifiable/Attainment.
Heard County (remainder)	.....	Unclassifiable/Attainment.
Houston County	.....	Unclassifiable/Attainment.
Irwin County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Jeff Davis County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Jenkins County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Jones County	.....	Unclassifiable/Attainment.
Lamar County	.....	Unclassifiable/Attainment.
Lanier County	.....	Unclassifiable/Attainment.
Laurens County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Liberty County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Long County	.....	Unclassifiable/Attainment.
Lowndes County	.....	Unclassifiable/Attainment.
Lumpkin County	.....	Unclassifiable/Attainment.
McDuffie County	.....	Unclassifiable/Attainment.
McIntosh County	.....	Unclassifiable/Attainment.
Macon County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Meriwether County	.....	Unclassifiable/Attainment.
Miller County	.....	Unclassifiable/Attainment.
Mitchell County	.....	Unclassifiable/Attainment.
Monroe County (remainder)	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Murray County	.....	Unclassifiable/Attainment.
Oconee County	.....	Unclassifiable/Attainment.

GEORGIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Oglethorpe County	.....	Unclassifiable/Attainment.
Peach County	.....	Unclassifiable/Attainment.
Pickens County	.....	Unclassifiable/Attainment.
Pierce County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Pulaski County	.....	Unclassifiable/Attainment.
Putnam County (remainder)	.....	Unclassifiable/Attainment.
Quitman County	.....	Unclassifiable/Attainment.
Rabun County	.....	Unclassifiable/Attainment.
Randolph County	.....	Unclassifiable/Attainment.
Richmond County	.....	Unclassifiable/Attainment.
Schley County	.....	Unclassifiable/Attainment.
Screven County	.....	Unclassifiable/Attainment.
Seminole County	.....	Unclassifiable/Attainment.
Stephens County	.....	Unclassifiable/Attainment.
Stewart County	.....	Unclassifiable/Attainment.
Sumter County	.....	Unclassifiable/Attainment.
Talbot County	.....	Unclassifiable/Attainment.
Taliaferro County	.....	Unclassifiable/Attainment.
Tattnall County	.....	Unclassifiable/Attainment.
Taylor County	.....	Unclassifiable/Attainment.
Telfair County	.....	Unclassifiable/Attainment.
Terrell County	.....	Unclassifiable/Attainment.
Thomas County	.....	Unclassifiable/Attainment.
Tift County	.....	Unclassifiable/Attainment.
Toombs County	.....	Unclassifiable/Attainment.
Towns County	.....	Unclassifiable/Attainment.
Treutlen County	.....	Unclassifiable/Attainment.
Troup County	.....	Unclassifiable/Attainment.
Turner County	.....	Unclassifiable/Attainment.
Twiggs County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Upson County	.....	Unclassifiable/Attainment.
Ware County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Webster County	.....	Unclassifiable/Attainment.
Wheeler County	.....	Unclassifiable/Attainment.
White County	.....	Unclassifiable/Attainment.
Whitfield County	.....	Unclassifiable/Attainment.
Wilcox County	.....	Unclassifiable/Attainment.
Wilkes County	.....	Unclassifiable/Attainment.
Wilkinson County	.....	Unclassifiable/Attainment.
Worth County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 13. In § 81.312, the table entitled ''Hawaii.—PM2.5'' is added to the end of the section to read as follows:

§ 81.312 Hawaii.

* * * * *

HAWAII.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Hawaii County	.....	Unclassifiable/Attainment.
Honolulu County	.....	Unclassifiable/Attainment.
Kalawao County	.....	Unclassifiable/Attainment.
Kauai County	.....	Unclassifiable/Attainment.
Maui County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 14. In § 81.313, the table entitled ''Idaho.—PM2.5'' is added to the end of the section to read as follows:

§ 81.313 Idaho.

* * * * *

IDAHO.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 61 Eastern Idaho Intrastate:		
Bannock County	.....	Unclassifiable/Attainment.
Bear Lake County	.....	Unclassifiable/Attainment.
Bingham County	.....	Unclassifiable/Attainment.
Bonneville County	.....	Unclassifiable/Attainment.
Butte County	.....	Unclassifiable/Attainment.
Caribou County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Fremont County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Oneida County	.....	Unclassifiable/Attainment.
Power County	.....	Unclassifiable/Attainment.
Teton County	.....	Unclassifiable/Attainment.
AQCR 62 E Washington-N Idaho Interstate:		
Benewah County	.....	Unclassifiable/Attainment.
Kootenai County	.....	Unclassifiable/Attainment.
Latah County	.....	Unclassifiable/Attainment.
Nez Perce County	.....	Unclassifiable/Attainment.
Shoshone County	.....	Unclassifiable/Attainment.
AQCR 63 Idaho Intrastate:		
Adams County	.....	Unclassifiable/Attainment.
Blaine County	.....	Unclassifiable/Attainment.
Boise County	.....	Unclassifiable/Attainment.
Bonner County	.....	Unclassifiable/Attainment.
Boundary County	.....	Unclassifiable/Attainment.
Camas County	.....	Unclassifiable/Attainment.
Cassia County	.....	Unclassifiable/Attainment.
Clearwater County	.....	Unclassifiable/Attainment.
Custer County	.....	Unclassifiable/Attainment.
Elmore County	.....	Unclassifiable/Attainment.
Gem County	.....	Unclassifiable/Attainment.
Gooding County	.....	Unclassifiable/Attainment.
Idaho County	.....	Unclassifiable/Attainment.
Jerome County	.....	Unclassifiable/Attainment.
Lemhi County	.....	Unclassifiable/Attainment.
Lewis County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Minidoka County	.....	Unclassifiable/Attainment.
Owyhee County	.....	Unclassifiable/Attainment.
Payette County	.....	Unclassifiable/Attainment.
Twin Falls County	.....	Unclassifiable/Attainment.
Valley County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
AQCR 64 Metropolitan Boise Interstate:		
Ada County	.....	Unclassifiable/Attainment.
Canyon County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 15. In § 81.314, the table entitled ''Illinois.—PM2.5'' is added to the end of the section to read as follows:

§ 81.314 Illinois.

* * * * *

ILLINOIS.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Chicago-Gary-Lake County, IL-IN:		
Cook County	.....	Nonattainment.
DuPage County	.....	Nonattainment.

ILLINOIS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Grundy County (part)	.....	Nonattainment.
Goose Lake and Aux Sable Townships		
Kane County	.....	Nonattainment.
Kendall County (part)	.....	Nonattainment.
Oswego Township		
Lake County	.....	Nonattainment.
McHenry County	.....	Nonattainment.
Will County	.....	Nonattainment.
St. Louis, MO-IL:		
Madison County	.....	Nonattainment.
Monroe County	.....	Nonattainment.
Randolph County (part)	.....	Nonattainment.
Baldwin Village		
St. Clair County	.....	Nonattainment.
Rest of State:		
Adams County	.....	Unclassifiable/Attainment.
Alexander County	.....	Unclassifiable/Attainment.
Bond County	.....	Unclassifiable/Attainment.
Boone County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Bureau County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Champaign County	.....	Unclassifiable/Attainment.
Christian County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Coles County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Cumberland County	.....	Unclassifiable/Attainment.
DeKalb County	.....	Unclassifiable/Attainment.
De Witt County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Edgar County	.....	Unclassifiable/Attainment.
Edwards County	.....	Unclassifiable/Attainment.
Effingham County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Ford County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Fulton County	.....	Unclassifiable/Attainment.
Gallatin County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Grundy County (remainder)	.....	Unclassifiable/Attainment.
Hamilton County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Hardin County	.....	Unclassifiable/Attainment.
Henderson County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Iroquois County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Jersey County	.....	Unclassifiable/Attainment.
Jo Daviess County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Kankakee County	.....	Unclassifiable/Attainment.
Kendall County (remainder)	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
La Salle County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Livingston County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
McDonough County	.....	Unclassifiable/Attainment.
McLean County	.....	Unclassifiable/Attainment.
Macon County	.....	Unclassifiable/Attainment.
Macoupin County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.

ILLINOIS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Marshall County	.....	Unclassifiable/Attainment.
Mason County	.....	Unclassifiable/Attainment.
Massac County	.....	Unclassifiable/Attainment.
Menard County	.....	Unclassifiable/Attainment.
Mercer County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Moultrie County	.....	Unclassifiable/Attainment.
Ogle County	.....	Unclassifiable/Attainment.
Peoria County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Piatt County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Pope County	.....	Unclassifiable/Attainment.
Pulaski County	.....	Unclassifiable/Attainment.
Putnam County	.....	Unclassifiable/Attainment.
Randolph County (remainder)	.....	Unclassifiable/Attainment.
Richland County	.....	Unclassifiable/Attainment.
Rock Island County	.....	Unclassifiable/Attainment.
Saline County	.....	Unclassifiable/Attainment.
Sangamon County	.....	Unclassifiable/Attainment.
Schuyler County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Stark County	.....	Unclassifiable/Attainment.
Stephenson County	.....	Unclassifiable/Attainment.
Tazewell County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Vermilion County	.....	Unclassifiable/Attainment.
Wabash County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
White County	.....	Unclassifiable/Attainment.
Whiteside County	.....	Unclassifiable/Attainment.
Williamson County	.....	Unclassifiable/Attainment.
Winnebago County	.....	Unclassifiable/Attainment.
Woodford County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 16. In § 81.315, the table entitled ''Indiana.—PM2.5'' is added to the end of the section to read as follows:

§ 81.315 Indiana.

* * * * *

INDIANA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Chicago-Gary-Lake County, IL-IN:		
Lake County	.....	Nonattainment.
Porter County	.....	Nonattainment.
Cincinnati-Hamilton, OH-KY-IN:		
Dearborn County (part)	.....	Nonattainment.
Lawrenceburg Township		
Elkhart, IN:		
Elkhart County	.....	Nonattainment.
St. Joseph County	.....	Nonattainment.
Evansville, IN:		
Dubois County	.....	Nonattainment.
Gibson County (part)	.....	Nonattainment.
Montgomery Township		
Pike County (part)	.....	Nonattainment.
Washington Township		
Spencer County (part)	.....	Nonattainment.
Ohio Township		

INDIANA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Vanderburgh County	.....	Nonattainment.
Warrick County	.....	Nonattainment.
Indianapolis, IN:		
Hamilton County	.....	Nonattainment.
Hendricks County	.....	Nonattainment.
Johnson County	.....	Nonattainment.
Marion County	.....	Nonattainment.
Morgan County	.....	Nonattainment.
Louisville, KY-IN:		
Clark County	.....	Nonattainment.
Floyd County	.....	Nonattainment.
Jefferson County (part)	.....	Nonattainment.
Madison Township		
Muncie, IN:		
Delaware County	.....	Unclassifiable.
Rest of State:		
Adams County	.....	Unclassifiable/Attainment.
Allen County	.....	Unclassifiable/Attainment.
Bartholomew County	.....	Unclassifiable/Attainment.
Benton County	.....	Unclassifiable/Attainment.
Blackford County	.....	Unclassifiable/Attainment.
Boone County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Daviess County	.....	Unclassifiable/Attainment.
Dearborn County (remainder)	.....	Unclassifiable/Attainment.
Decatur County	.....	Unclassifiable/Attainment.
De Kalb County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Fountain County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Fulton County	.....	Unclassifiable/Attainment.
Gibson County (remainder)	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Harrison County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Howard County	.....	Unclassifiable/Attainment.
Huntington County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Jay County	.....	Unclassifiable/Attainment.
Jefferson County (remainder)	.....	Unclassifiable/Attainment.
Jennings County	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
Kosciusko County	.....	Unclassifiable/Attainment.
LaGrange County	.....	Unclassifiable/Attainment.
La Porte County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Martin County	.....	Unclassifiable/Attainment.
Miami County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Newton County	.....	Unclassifiable/Attainment.
Noble County	.....	Unclassifiable/Attainment.
Ohio County	.....	Unclassifiable/Attainment.
Orange County	.....	Unclassifiable/Attainment.
Owen County	.....	Unclassifiable/Attainment.
Parke County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pike County (remainder)	.....	Unclassifiable/Attainment.
Posey County	.....	Unclassifiable/Attainment.
Pulaski County	.....	Unclassifiable/Attainment.

INDIANA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Putnam County	.....	Unclassifiable/Attainment.
Randolph County	.....	Unclassifiable/Attainment.
Ripley County	.....	Unclassifiable/Attainment.
Rush County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Spencer County (remainder)	.....	Unclassifiable/Attainment.
Starke County	.....	Unclassifiable/Attainment.
Steuben County	.....	Unclassifiable/Attainment.
Sullivan County	.....	Unclassifiable/Attainment.
Switzerland County	.....	Unclassifiable/Attainment.
Tippecanoe County	.....	Unclassifiable/Attainment.
Tipton County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Vermillion County	.....	Unclassifiable/Attainment.
Vigo County	.....	Unclassifiable/Attainment.
Wabash County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Wells County	.....	Unclassifiable/Attainment.
White County	.....	Unclassifiable/Attainment.
Whitley County	.....	Unclassifiable/Attainment.

[1] Includes Indian Country located in each county or area, except as otherwise specified.
[a] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 17. In § 81.316, the table entitled ''Iowa.—PM2.5'' is added to the end of the section to read as follows:

§ 81.316 Iowa.

* * * * *

IOWA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Adair County	.....	Unclassifiable/Attainment.
Adams County	.....	Unclassifiable/Attainment.
Allamakee County	.....	Unclassifiable/Attainment.
Appanoose County	.....	Unclassifiable/Attainment.
Audubon County	.....	Unclassifiable/Attainment.
Benton County	.....	Unclassifiable/Attainment.
Black Hawk County	.....	Unclassifiable/Attainment.
Boone County	.....	Unclassifiable/Attainment.
Bremer County	.....	Unclassifiable/Attainment.
Buchanan County	.....	Unclassifiable/Attainment.
Buena Vista County	.....	Unclassifiable/Attainment.
Butler County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Cedar County	.....	Unclassifiable/Attainment.
Cerro Gordo County	.....	Unclassifiable/Attainment.
Cherokee County	.....	Unclassifiable/Attainment.
Chickasaw County	.....	Unclassifiable/Attainment.
Clarke County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Clayton County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Dallas County	.....	Unclassifiable/Attainment.
Davis County	.....	Unclassifiable/Attainment.
Decatur County	.....	Unclassifiable/Attainment.
Delaware County	.....	Unclassifiable/Attainment.
Des Moines County	.....	Unclassifiable/Attainment.
Dickinson County	.....	Unclassifiable/Attainment.
Dubuque County	.....	Unclassifiable/Attainment.

IOWA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Emmet County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Floyd County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Fremont County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Grundy County	.....	Unclassifiable/Attainment.
Guthrie County	.....	Unclassifiable/Attainment.
Hamilton County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Hardin County	.....	Unclassifiable/Attainment.
Harrison County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Howard County	.....	Unclassifiable/Attainment.
Humboldt County	.....	Unclassifiable/Attainment.
Ida County	.....	Unclassifiable/Attainment.
Iowa County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Jones County	.....	Unclassifiable/Attainment.
Keokuk County	.....	Unclassifiable/Attainment.
Kossuth County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Linn County	.....	Unclassifiable/Attainment.
Louisa County	.....	Unclassifiable/Attainment.
Lucas County	.....	Unclassifiable/Attainment.
Lyon County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Mahaska County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Mills County	.....	Unclassifiable/Attainment.
Mitchell County	.....	Unclassifiable/Attainment.
Monona County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Muscatine County	.....	Unclassifiable/Attainment.
O'Brien County	.....	Unclassifiable/Attainment.
Osceola County	.....	Unclassifiable/Attainment.
Page County	.....	Unclassifiable/Attainment.
Palo Alto County	.....	Unclassifiable/Attainment.
Plymouth County	.....	Unclassifiable/Attainment.
Pocahontas County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Pottawattamie County	.....	Unclassifiable/Attainment.
Poweshiek County	.....	Unclassifiable/Attainment.
Ringgold County	.....	Unclassifiable/Attainment.
Sac County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Sioux County	.....	Unclassifiable/Attainment.
Story County	.....	Unclassifiable/Attainment.
Tama County	.....	Unclassifiable/Attainment.
Taylor County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Van Buren County	.....	Unclassifiable/Attainment.
Wapello County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Webster County	.....	Unclassifiable/Attainment.
Winnebago County	.....	Unclassifiable/Attainment.
Winneshiek County	.....	Unclassifiable/Attainment.
Woodbury County	.....	Unclassifiable/Attainment.
Worth County	.....	Unclassifiable/Attainment.
Wright County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 18. In § 81.317, the table entitled ''Kansas—PM2.5'' is added to the end of the section to read as follows:

§ 81.317 Kansas.

* * * * *

KANSAS.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Allen County	.....	Unclassifiable/Attainment.
Anderson County	.....	Unclassifiable/Attainment.
Atchison County	.....	Unclassifiable/Attainment.
Barber County	.....	Unclassifiable/Attainment.
Barton County	.....	Unclassifiable/Attainment.
Bourbon County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Butler County	.....	Unclassifiable/Attainment.
Chase County	.....	Unclassifiable/Attainment.
Chautauqua County	.....	Unclassifiable/Attainment.
Cherokee County	.....	Unclassifiable/Attainment.
Cheyenne County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Cloud County	.....	Unclassifiable/Attainment.
Coffey County	.....	Unclassifiable/Attainment.
Comanche County	.....	Unclassifiable/Attainment.
Cowley County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Decatur County	.....	Unclassifiable/Attainment.
Dickinson County	.....	Unclassifiable/Attainment.
Doniphan County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Edwards County	.....	Unclassifiable/Attainment.
Elk County	.....	Unclassifiable/Attainment.
Ellis County	.....	Unclassifiable/Attainment.
Ellsworth County	.....	Unclassifiable/Attainment.
Finney County	.....	Unclassifiable/Attainment.
Ford County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Geary County	.....	Unclassifiable/Attainment.
Gove County	.....	Unclassifiable/Attainment.
Graham County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Gray County	.....	Unclassifiable/Attainment.
Greeley County	.....	Unclassifiable/Attainment.
Greenwood County	.....	Unclassifiable/Attainment.
Hamilton County	.....	Unclassifiable/Attainment.
Harper County	.....	Unclassifiable/Attainment.
Harvey County	.....	Unclassifiable/Attainment.
Haskell County	.....	Unclassifiable/Attainment.
Hodgeman County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Jewell County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Kearny County	.....	Unclassifiable/Attainment.
Kingman County	.....	Unclassifiable/Attainment.
Kiowa County	.....	Unclassifiable/Attainment.
Labette County	.....	Unclassifiable/Attainment.
Lane County	.....	Unclassifiable/Attainment.
Leavenworth County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Linn County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
Lyon County	.....	Unclassifiable/Attainment.
McPherson County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Meade County	.....	Unclassifiable/Attainment.
Miami County	.....	Unclassifiable/Attainment.
Mitchell County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Morris County	.....	Unclassifiable/Attainment.
Morton County	.....	Unclassifiable/Attainment.

KANSAS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Nemaha County	.....	Unclassifiable/Attainment.
Neosho County	.....	Unclassifiable/Attainment.
Ness County	.....	Unclassifiable/Attainment.
Norton County	.....	Unclassifiable/Attainment.
Osage County	.....	Unclassifiable/Attainment.
Osborne County	.....	Unclassifiable/Attainment.
Ottawa County	.....	Unclassifiable/Attainment.
Pawnee County	.....	Unclassifiable/Attainment.
Phillips County	.....	Unclassifiable/Attainment.
Pottawatomie County	.....	Unclassifiable/Attainment.
Pratt County	.....	Unclassifiable/Attainment.
Rawlins County	.....	Unclassifiable/Attainment.
Reno County	.....	Unclassifiable/Attainment.
Republic County	.....	Unclassifiable/Attainment.
Rice County	.....	Unclassifiable/Attainment.
Riley County	.....	Unclassifiable/Attainment.
Rooks County	.....	Unclassifiable/Attainment.
Rush County	.....	Unclassifiable/Attainment.
Russell County	.....	Unclassifiable/Attainment.
Saline County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Sedgwick County	.....	Unclassifiable/Attainment.
Seward County	.....	Unclassifiable/Attainment.
Shawnee County	.....	Unclassifiable/Attainment.
Sheridan County	.....	Unclassifiable/Attainment.
Sherman County	.....	Unclassifiable/Attainment.
Smith County	.....	Unclassifiable/Attainment.
Stafford County	.....	Unclassifiable/Attainment.
Stanton County	.....	Unclassifiable/Attainment.
Stevens County	.....	Unclassifiable/Attainment.
Sumner County	.....	Unclassifiable/Attainment.
Thomas County	.....	Unclassifiable/Attainment.
Trego County	.....	Unclassifiable/Attainment.
Wabaunsee County	.....	Unclassifiable/Attainment.
Wallace County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wichita County	.....	Unclassifiable/Attainment.
Wilson County	.....	Unclassifiable/Attainment.
Woodson County	.....	Unclassifiable/Attainment.
Wyandotte County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 19. In § 81.318, the table entitled ''Kentucky.—PM2.5'' is added to the end of the section to read as follows:

§ 81.318 Kentucky.

* * * * *

KENTUCKY.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Cincinnati-Hamilton, OH-KY-IN:		
Boone County	.....	Nonattainment.
Campbell County	.....	Nonattainment.
Kenton County	.....	Nonattainment.
Huntington-Ashland, WV-KY-OH:		
Boyd County	.....	Nonattainment.
Lawrence County (part)	.....	Nonattainment.
The area described by U.S. Census 2000 block group identifier 21–127–9901–6.		
Lexington, KY:		
Fayette County	.....	Nonattainment.
Mercer County (part)	.....	Nonattainment.
The area described by U.S. Census 2000 block group identifier 21–167–9605–1.		
Louisville, KY-IN:		
Bullitt County	.....	Nonattainment.
Jefferson County	.....	Nonattainment.

KENTUCKY.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Rest of State:		
Adair County	.....	Unclassifiable/Attainment.
Allen County	.....	Unclassifiable/Attainment.
Anderson County	.....	Unclassifiable/Attainment.
Ballard County	.....	Unclassifiable/Attainment.
Barren County	.....	Unclassifiable/Attainment.
Bath County	.....	Unclassifiable/Attainment.
Bell County	.....	Unclassifiable/Attainment.
Bourbon County	.....	Unclassifiable/Attainment.
Boyle County	.....	Unclassifiable/Attainment.
Bracken County	.....	Unclassifiable/Attainment.
Breathitt County	.....	Unclassifiable/Attainment.
Breckinridge County	.....	Unclassifiable/Attainment.
Butler County	.....	Unclassifiable/Attainment.
Caldwell County	.....	Unclassifiable/Attainment.
Calloway County	.....	Unclassifiable/Attainment.
Carlisle County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Carter County	.....	Unclassifiable/Attainment.
Casey County	.....	Unclassifiable/Attainment.
Christian County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Crittenden County	.....	Unclassifiable/Attainment.
Cumberland County	.....	Unclassifiable/Attainment.
Daviess County	.....	Unclassifiable/Attainment.
Edmonson County	.....	Unclassifiable/Attainment.
Elliott County	.....	Unclassifiable/Attainment.
Estill County	.....	Unclassifiable/Attainment.
Fleming County	.....	Unclassifiable/Attainment.
Floyd County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Fulton County	.....	Unclassifiable/Attainment.
Gallatin County	.....	Unclassifiable/Attainment.
Garrard County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Graves County	.....	Unclassifiable/Attainment.
Grayson County	.....	Unclassifiable/Attainment.
Green County	.....	Unclassifiable/Attainment.
Greenup County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Hardin County	.....	Unclassifiable/Attainment.
Harlan County	.....	Unclassifiable/Attainment.
Harrison County	.....	Unclassifiable/Attainment.
Hart County	.....	Unclassifiable/Attainment.
Henderson County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Hickman County	.....	Unclassifiable/Attainment.
Hopkins County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jessamine County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Knott County	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
Larue County	.....	Unclassifiable/Attainment.
Laurel County	.....	Unclassifiable/Attainment.
Lawrence County (remainder)	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Leslie County	.....	Unclassifiable/Attainment.
Letcher County	.....	Unclassifiable/Attainment.
Lewis County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Livingston County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
Lyon County	.....	Unclassifiable/Attainment.
McCracken County	.....	Unclassifiable/Attainment.
McCreary County	.....	Unclassifiable/Attainment.
McLean County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.

KENTUCKY.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Magoffin County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Martin County	.....	Unclassifiable/Attainment.
Mason County	.....	Unclassifiable/Attainment.
Meade County	.....	Unclassifiable/Attainment.
Menifee County	.....	Unclassifiable/Attainment.
Mercer County (remainder)	.....	Unclassifiable/Attainment.
Metcalfe County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Muhlenberg County	.....	Unclassifiable/Attainment.
Nelson County	.....	Unclassifiable/Attainment.
Nicholas County	.....	Unclassifiable/Attainment.
Ohio County	.....	Unclassifiable/Attainment.
Oldham County	.....	Unclassifiable/Attainment.
Owen County	.....	Unclassifiable/Attainment.
Owsley County	.....	Unclassifiable/Attainment.
Pendleton County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Powell County	.....	Unclassifiable/Attainment.
Pulaski County	.....	Unclassifiable/Attainment.
Robertson County	.....	Unclassifiable/Attainment.
Rockcastle County	.....	Unclassifiable/Attainment.
Rowan County	.....	Unclassifiable/Attainment.
Russell County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Simpson County	.....	Unclassifiable/Attainment.
Spencer County	.....	Unclassifiable/Attainment.
Taylor County	.....	Unclassifiable/Attainment.
Todd County	.....	Unclassifiable/Attainment.
Trigg County	.....	Unclassifiable/Attainment.
Trimble County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Webster County	.....	Unclassifiable/Attainment.
Whitley County	.....	Unclassifiable/Attainment.
Wolfe County	.....	Unclassifiable/Attainment.
Woodford County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 20. In § 81.319, the table entitled ''Louisiana—PM2.5'' is added to the end of the section to read as follows:

§ 81.319 Louisiana.

* * * * *

LOUISIANA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 019 Monroe-El Dorado Interstate:		
Caldwell Parish	.....	Unclassifiable/Attainment.
Catahoula Parish	.....	Unclassifiable/Attainment.
Concordia Parish	.....	Unclassifiable/Attainment.
East Carroll Parish	.....	Unclassifiable/Attainment.
Franklin Parish	.....	Unclassifiable/Attainment.
La Salle Parish	.....	Unclassifiable/Attainment.
Madison Parish	.....	Unclassifiable/Attainment.
Morehouse Parish	.....	Unclassifiable/Attainment.
Ouachita Parish	.....	Unclassifiable/Attainment.
Richland Parish	.....	Unclassifiable/Attainment.

LOUISIANA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Tensas Parish	.....	Unclassifiable/Attainment.
Union Parish	.....	Unclassifiable/Attainment.
West Carroll Parish	.....	Unclassifiable/Attainment.
AQCR 022 Shreveport-Texarkana-Tyler Interstate:		
Bienville Parish	.....	Unclassifiable/Attainment.
Bossier Parish	.....	Unclassifiable/Attainment.
Caddo Parish	.....	Unclassifiable/Attainment.
Claiborne Parish	.....	Unclassifiable/Attainment.
De Soto Parish	.....	Unclassifiable/Attainment.
Jackson Parish	.....	Unclassifiable/Attainment.
Lincoln Parish	.....	Unclassifiable/Attainment.
Natchitoches Parish	.....	Unclassifiable/Attainment.
Red River Parish	.....	Unclassifiable/Attainment.
Sabine Parish	.....	Unclassifiable/Attainment.
Webster Parish	.....	Unclassifiable/Attainment.
Winn Parish	.....	Unclassifiable/Attainment.
AQCR 106 S. Louisiana-S.E. Texas Interstate:		
Acadia Parish	.....	Unclassifiable/Attainment.
Allen Parish	.....	Unclassifiable/Attainment.
Assumption Parish	.....	Unclassifiable/Attainment.
Avoyelles Parish	.....	Unclassifiable/Attainment.
Cameron Parish	.....	Unclassifiable/Attainment.
East Feliciana Parish	.....	Unclassifiable/Attainment.
Evangeline Parish	.....	Unclassifiable/Attainment.
Iberia Parish	.....	Unclassifiable/Attainment.
Jefferson Davis Parish	.....	Unclassifiable/Attainment.
Plaquemines Parish	.....	Unclassifiable/Attainment.
Rapides Parish	.....	Unclassifiable/Attainment.
St. Helena Parish	.....	Unclassifiable/Attainment.
St. John the Baptist Parish	.....	Unclassifiable/Attainment.
St. Landry Parish	.....	Unclassifiable/Attainment.
St. Martin Parish	.....	Unclassifiable/Attainment.
St. Tammany Parish	.....	Unclassifiable/Attainment.
Tangipahoa Parish	.....	Unclassifiable/Attainment.
Terrebonne Parish	.....	Unclassifiable/Attainment.
Vermilion Parish	.....	Unclassifiable/Attainment.
Vernon Parish	.....	Unclassifiable/Attainment.
Washington Parish	.....	Unclassifiable/Attainment.
West Feliciana Parish	.....	Unclassifiable/Attainment.
Baton Rouge, LA:		
Ascension Parish	.....	Unclassifiable/Attainment.
East Baton Rouge Parish	.....	Unclassifiable/Attainment.
Iberville Parish	.....	Unclassifiable/Attainment.
Livingston Parish	.....	Unclassifiable/Attainment.
West Baton Rouge Parish	.....	Unclassifiable/Attainment.
Beauregard Parish Area, LA:		
Beauregard Parish	.....	Unclassifiable/Attainment.
Grant Parish Area:		
Grant Parish	.....	Unclassifiable/Attainment.
Lafayette Area:		
Lafayette Parish	.....	Unclassifiable/Attainment.
Lafourche Parish Area:		
Lafourche Parish	.....	Unclassifiable/Attainment.
Lake Charles Area:		
Calcasieu Parish	.....	Unclassifiable/Attainment.
New Orleans Area:		
Jefferson Parish	.....	Unclassifiable/Attainment.
Orleans Parish	.....	Unclassifiable/Attainment.
St. Bernard Parish	.....	Unclassifiable/Attainment.
St. Charles Parish	.....	Unclassifiable/Attainment.
Pointe Coupee Area:		
Pointe Coupee Parish	.....	Unclassifiable/Attainment.
St. James Parish Area:		
St. James Parish	.....	Unclassifiable/Attainment.
St. Mary Parish Area:		
St. Mary Parish	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 21. In § 81.320, the table entitled ''Maine—PM2.5'' is added to the end of the section to read as follows:

§ 81.320 Maine.

* * * * *

MAINE.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Androscoggin County	.....	Unclassifiable/Attainment.
Aroostook County	.....	Unclassifiable/Attainment.
Cumberland County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Kennebec County	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Oxford County	.....	Unclassifiable/Attainment.
Penobscot County	.....	Unclassifiable/Attainment.
Piscataquis County	.....	Unclassifiable/Attainment.
Sagadahoc County	.....	Unclassifiable/Attainment.
Somerset County	.....	Unclassifiable/Attainment.
Waldo County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
York County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 22. In § 81.321, the table entitled ''Maryland.—PM2.5'' is added to the end of the section to read as follows:

§ 81.321 Maryland.

* * * * *

MARYLAND.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Baltimore, MD:		
Anne Arundel County	.....	NonAttainment.
Baltimore County	.....	NonAttainment.
Carroll County	.....	NonAttainment.
Harford County	.....	NonAttainment.
Howard County	.....	NonAttainment.
City of Baltimore	.....	NonAttainment.
Martinsburg, WV-Hagerstown, MD:		
Washington County	.....	NonAttainment.
Washington, DC-MD-VA:		
Charles County	.....	NonAttainment.
Frederick County	.....	NonAttainment.
Montgomery County	.....	NonAttainment.
Prince George's County	.....	NonAttainment.
AQCR 113 Cumberland-Keyser Interstate:		
Allegany County	.....	Unclassifiable/Attainment.
Garrett County	.....	Unclassifiable/Attainment.
AQCR 114 Eastern Shore Interstate (remainder of):		
Caroline County	.....	Unclassifiable/Attainment.
Cecil County	.....	Unclassifiable/Attainment.
Dorchester County	.....	Unclassifiable/Attainment.
Kent County	.....	Unclassifiable/Attainment.
Queen Anne's County	.....	Unclassifiable/Attainment.
Somerset County	.....	Unclassifiable/Attainment.
Talbot County	.....	Unclassifiable/Attainment.
Wicomico County	.....	Unclassifiable/Attainment.
Worcester County	.....	Unclassifiable/Attainment.
AQCR 116 Southern Maryland Intrastate (remainder of):		
Calvert County	.....	Unclassifiable/Attainment.
St. Mary's County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 23. In § 81.322, the table entitled ''Massachusetts.—PM2.5'' is added to the end of the section to read as follows:

§ 81.322 Massachusetts.

* * * * *

MASSACHUSETTS.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Barnstable County	.....	Unclassifiable/Attainment.
Berkshire County	.....	Unclassifiable/Attainment.
Bristol County	.....	Unclassifiable/Attainment.
Dukes County	.....	Unclassifiable/Attainment.
Essex County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Hampden County	.....	Unclassifiable/Attainment.
Hampshire County	.....	Unclassifiable/Attainment.
Middlesex County	.....	Unclassifiable/Attainment.
Nantucket County	.....	Unclassifiable/Attainment.
Norfolk County	.....	Unclassifiable/Attainment.
Plymouth County	.....	Unclassifiable/Attainment.
Suffolk County	.....	Unclassifiable/Attainment.
Worcester County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 24. In § 81.323, the table entitled ''Michigan.—PM2.5'' is added to the end of the section to read as follows:

§ 81.323 Michigan.

* * * * *

MICHIGAN.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Detroit-Ann Arbor, MI:		
Livingston County	.....	Nonattainment.
Macomb County	.....	Nonattainment.
Monroe County	.....	Nonattainment.
Oakland County	.....	Nonattainment.
St. Clair County	.....	Nonattainment.
Washtenaw County	.....	Nonattainment.
Wayne County	.....	Nonattainment.
Rest of State:		
Alcona County	.....	Unclassifiable/Attainment.
Alger County	.....	Unclassifiable/Attainment.
Allegan County	.....	Unclassifiable/Attainment.
Alpena County	.....	Unclassifiable/Attainment.
Antrim County	.....	Unclassifiable/Attainment.
Arenac County	.....	Unclassifiable/Attainment.
Baraga County	.....	Unclassifiable/Attainment.
Barry County	.....	Unclassifiable/Attainment.
Bay County	.....	Unclassifiable/Attainment.
Benzie County	.....	Unclassifiable/Attainment.
Berrien County	.....	Unclassifiable/Attainment.
Branch County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Charlevoix County	.....	Unclassifiable/Attainment.
Cheboygan County	.....	Unclassifiable/Attainment.
Chippewa County	.....	Unclassifiable/Attainment.
Clare County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Delta County	.....	Unclassifiable/Attainment.
Dickinson County	.....	Unclassifiable/Attainment.
Eaton County	.....	Unclassifiable/Attainment.
Emmet County	.....	Unclassifiable/Attainment.
Genesee County	.....	Unclassifiable/Attainment.
Gladwin County	.....	Unclassifiable/Attainment.
Gogebic County	.....	Unclassifiable/Attainment.

MICHIGAN.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Grand Traverse County	.....	Unclassifiable/Attainment.
Gratiot County	.....	Unclassifiable/Attainment.
Hillsdale County	.....	Unclassifiable/Attainment.
Houghton County	.....	Unclassifiable/Attainment.
Huron County	.....	Unclassifiable/Attainment.
Ingham County	.....	Unclassifiable/Attainment.
Ionia County	.....	Unclassifiable/Attainment.
Iosco County	.....	Unclassifiable/Attainment.
Iron County	.....	Unclassifiable/Attainment.
Isabella County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Kalamazoo County	.....	Unclassifiable/Attainment.
Kalkaska County	.....	Unclassifiable/Attainment.
Kent County	.....	Unclassifiable/Attainment.
Keweenaw County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.
Lapeer County	.....	Unclassifiable/Attainment.
Leelanau County	.....	Unclassifiable/Attainment.
Lenawee County	.....	Unclassifiable/Attainment.
Luce County	.....	Unclassifiable/Attainment.
Mackinac County	.....	Unclassifiable/Attainment.
Manistee County	.....	Unclassifiable/Attainment.
Marquette County	.....	Unclassifiable/Attainment.
Mason County	.....	Unclassifiable/Attainment.
Mecosta County	.....	Unclassifiable/Attainment.
Menominee County	.....	Unclassifiable/Attainment.
Midland County	.....	Unclassifiable/Attainment.
Missaukee County	.....	Unclassifiable/Attainment.
Montcalm County	.....	Unclassifiable/Attainment.
Montmorency County	.....	Unclassifiable/Attainment.
Muskegon County	.....	Unclassifiable/Attainment.
Newaygo County	.....	Unclassifiable/Attainment.
Oceana County	.....	Unclassifiable/Attainment.
Ogemaw County	.....	Unclassifiable/Attainment.
Ontonagon County	.....	Unclassifiable/Attainment.
Osceola County	.....	Unclassifiable/Attainment.
Oscoda County	.....	Unclassifiable/Attainment.
Otsego County	.....	Unclassifiable/Attainment.
Ottawa County	.....	Unclassifiable/Attainment.
Presque Isle County	.....	Unclassifiable/Attainment.
Roscommon County	.....	Unclassifiable/Attainment.
Saginaw County	.....	Unclassifiable/Attainment.
St. Joseph County	.....	Unclassifiable/Attainment.
Sanilac County	.....	Unclassifiable/Attainment.
Schoolcraft County	.....	Unclassifiable/Attainment.
Shiawassee County	.....	Unclassifiable/Attainment.
Tuscola County	.....	Unclassifiable/Attainment.
Van Buren County	.....	Unclassifiable/Attainment.
Wexford County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 25. In § 81324, the table entitled ''Minnesota.—PM2.5'' is added to the end of the section to read as follows:

§ 81.324 Minnesota.

* * * * *

MINNESOTA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Aitkin County	.....	Unclassifiable/Attainment.
Anoka County	.....	Unclassifiable/Attainment.
Becker County	.....	Unclassifiable/Attainment.
Beltrami County	.....	Unclassifiable/Attainment.
Benton County	.....	Unclassifiable/Attainment.

MINNESOTA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Big Stone County	.....	Unclassifiable/Attainment.
Blue Earth County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Carlton County	.....	Unclassifiable/Attainment.
Carver County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Chippewa County	.....	Unclassifiable/Attainment.
Chisago County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Clearwater County	.....	Unclassifiable/Attainment.
Cook County	.....	Unclassifiable/Attainment.
Cottonwood County	.....	Unclassifiable/Attainment.
Crow Wing County	.....	Unclassifiable/Attainment.
Dakota County	.....	Unclassifiable/Attainment.
Dodge County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Faribault County	.....	Unclassifiable/Attainment.
Fillmore County	.....	Unclassifiable/Attainment.
Freeborn County	.....	Unclassifiable/Attainment.
Goodhue County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Hennepin County	.....	Unclassifiable/Attainment.
Houston County	.....	Unclassifiable/Attainment.
Hubbard County	.....	Unclassifiable/Attainment.
Isanti County	.....	Unclassifiable/Attainment.
Itasca County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Kanabec County	.....	Unclassifiable/Attainment.
Kandiyohi County	.....	Unclassifiable/Attainment.
Kittson County	.....	Unclassifiable/Attainment.
Koochiching County	.....	Unclassifiable/Attainment.
Lac qui Parle County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.
Lake of the Woods County	.....	Unclassifiable/Attainment.
Le Sueur County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Lyon County	.....	Unclassifiable/Attainment.
McLeod County	.....	Unclassifiable/Attainment.
Mahnomen County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Martin County	.....	Unclassifiable/Attainment.
Meeker County	.....	Unclassifiable/Attainment.
Mille Lacs County	.....	Unclassifiable/Attainment.
Morrison County	.....	Unclassifiable/Attainment.
Mower County	.....	Unclassifiable/Attainment.
Murray County	.....	Unclassifiable/Attainment.
Nicollet County	.....	Unclassifiable/Attainment.
Nobles County	.....	Unclassifiable/Attainment.
Norman County	.....	Unclassifiable/Attainment.
Olmsted County	.....	Unclassifiable/Attainment.
Otter Tail County	.....	Unclassifiable/Attainment.
Pennington County	.....	Unclassifiable/Attainment.
Pine County	.....	Unclassifiable/Attainment.
Pipestone County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Pope County	.....	Unclassifiable/Attainment.
Ramsey County	.....	Unclassifiable/Attainment.
Red Lake County	.....	Unclassifiable/Attainment.
Redwood County	.....	Unclassifiable/Attainment.
Renville County	.....	Unclassifiable/Attainment.
Rice County	.....	Unclassifiable/Attainment.
Rock County	.....	Unclassifiable/Attainment.
Roseau County	.....	Unclassifiable/Attainment.
St. Louis County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Sherburne County	.....	Unclassifiable/Attainment.
Sibley County	.....	Unclassifiable/Attainment.
Stearns County	.....	Unclassifiable/Attainment.
Steele County	.....	Unclassifiable/Attainment.
Stevens County	.....	Unclassifiable/Attainment.

MINNESOTA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Swift County	.....	Unclassifiable/Attainment.
Todd County	.....	Unclassifiable/Attainment.
Traverse County	.....	Unclassifiable/Attainment.
Wabasha County	.....	Unclassifiable/Attainment.
Wadena County	.....	Unclassifiable/Attainment.
Waseca County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Watonwan County	.....	Unclassifiable/Attainment.
Wilkin County	.....	Unclassifiable/Attainment.
Winona County	.....	Unclassifiable/Attainment.
Wright County	.....	Unclassifiable/Attainment.
Yellow Medicine County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 26. In § 81.325, the table entitled ''Mississippi.—PM2.5'' is added to the end of the section to read as follows:

§ 81.325 Mississippi.

* * * * *

MISSISSIPPI.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Adams County	.....	Unclassifiable/Attainment.
Alcorn County	.....	Unclassifiable/Attainment.
Amite County	.....	Unclassifiable/Attainment.
Attala County	.....	Unclassifiable/Attainment.
Benton County	.....	Unclassifiable/Attainment.
Bolivar County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Chickasaw County	.....	Unclassifiable/Attainment.
Choctaw County	.....	Unclassifiable/Attainment.
Claiborne County	.....	Unclassifiable/Attainment.
Clarke County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Coahoma County	.....	Unclassifiable/Attainment.
Copiah County	.....	Unclassifiable/Attainment.
Covington County	.....	Unclassifiable/Attainment.
DeSoto County	.....	Unclassifiable/Attainment.
Forrest County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
George County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Grenada County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Harrison County	.....	Unclassifiable/Attainment.
Hinds County	.....	Unclassifiable/Attainment.
Holmes County	.....	Unclassifiable/Attainment.
Humphreys County	.....	Unclassifiable/Attainment.
Issaquena County	.....	Unclassifiable/Attainment.
Itawamba County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Jefferson Davis County	.....	Unclassifiable/Attainment.
Jones County	.....	Unclassifiable/Attainment.
Kemper County	.....	Unclassifiable/Attainment.
Lafayette County	.....	Unclassifiable/Attainment.
Lamar County	.....	Unclassifiable/Attainment.
Lauderdale County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.
Leake County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Leflore County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.

MISSISSIPPI.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Lowndes County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Neshoba County	.....	Unclassifiable/Attainment.
Newton County	.....	Unclassifiable/Attainment.
Noxubee County	.....	Unclassifiable/Attainment.
Oktibbeha County	.....	Unclassifiable/Attainment.
Panola County	.....	Unclassifiable/Attainment.
Pearl River County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Pontotoc County	.....	Unclassifiable/Attainment.
Prentiss County	.....	Unclassifiable/Attainment.
Quitman County	.....	Unclassifiable/Attainment.
Rankin County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Sharkey County	.....	Unclassifiable/Attainment.
Simpson County	.....	Unclassifiable/Attainment.
Smith County	.....	Unclassifiable/Attainment.
Stone County	.....	Unclassifiable/Attainment.
Sunflower County	.....	Unclassifiable/Attainment.
Tallahatchie County	.....	Unclassifiable/Attainment.
Tate County	.....	Unclassifiable/Attainment.
Tippah County	.....	Unclassifiable/Attainment.
Tishomingo County	.....	Unclassifiable/Attainment.
Tunica County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Walthall County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Webster County	.....	Unclassifiable/Attainment.
Wilkinson County	.....	Unclassifiable/Attainment.
Winston County	.....	Unclassifiable/Attainment.
Yalobusha County	.....	Unclassifiable/Attainment.
Yazoo County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 27. In § 81.326, the table entitled ''Missouri.—PM2.5'' is added to the end of the section to read as follows:

§ 81.326 Missouri.

* * * * *

MISSOURI.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
St. Louis, MO-IL:		
Franklin County	.....	Nonattainment.
Jefferson County	.....	Nonattainment.
St. Charles County	.....	Nonattainment.
St. Louis County	.....	Nonattainment.
St. Louis City	.....	Nonattainment.
Rest of State:		
Adair County	.....	Unclassifiable/Attainment.
Andrew County	.....	Unclassifiable/Attainment.
Atchison County	.....	Unclassifiable/Attainment.
Audrain County	.....	Unclassifiable/Attainment.
Barry County	.....	Unclassifiable/Attainment.
Barton County	.....	Unclassifiable/Attainment.
Bates County	.....	Unclassifiable/Attainment.
Benton County	.....	Unclassifiable/Attainment.
Bollinger County	.....	Unclassifiable/Attainment.

MISSOURI.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Boone County	.....	Unclassifiable/Attainment.
Buchanan County	.....	Unclassifiable/Attainment.
Butler County	.....	Unclassifiable/Attainment.
Caldwell County	.....	Unclassifiable/Attainment.
Callaway County	.....	Unclassifiable/Attainment.
Camden County	.....	Unclassifiable/Attainment.
Cape Girardeau County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Carter County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Cedar County	.....	Unclassifiable/Attainment.
Chariton County	.....	Unclassifiable/Attainment.
Christian County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Cole County	.....	Unclassifiable/Attainment.
Cooper County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Dade County	.....	Unclassifiable/Attainment.
Dallas County	.....	Unclassifiable/Attainment.
Daviess County	.....	Unclassifiable/Attainment.
DeKalb County	.....	Unclassifiable/Attainment.
Dent County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Dunklin County	.....	Unclassifiable/Attainment.
Gasconade County	.....	Unclassifiable/Attainment.
Gentry County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Grundy County	.....	Unclassifiable/Attainment.
Harrison County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Hickory County	.....	Unclassifiable/Attainment.
Holt County	.....	Unclassifiable/Attainment.
Howard County	.....	Unclassifiable/Attainment.
Howell County	.....	Unclassifiable/Attainment.
Iron County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
Laclede County	.....	Unclassifiable/Attainment.
Lafayette County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.
Lewis County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Linn County	.....	Unclassifiable/Attainment.
Livingston County	.....	Unclassifiable/Attainment.
McDonald County	.....	Unclassifiable/Attainment.
Macon County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Maries County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Mercer County	.....	Unclassifiable/Attainment.
Miller County	.....	Unclassifiable/Attainment.
Mississippi County	.....	Unclassifiable/Attainment.
Moniteau County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
New Madrid County	.....	Unclassifiable/Attainment.
Newton County	.....	Unclassifiable/Attainment.
Oregon County	.....	Unclassifiable/Attainment.
Osage County	.....	Unclassifiable/Attainment.
Ozark County	.....	Unclassifiable/Attainment.
Pemiscot County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pettis County	.....	Unclassifiable/Attainment.
Phelps County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.

MISSOURI.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Platte County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Pulaski County	.....	Unclassifiable/Attainment.
Putnam County	.....	Unclassifiable/Attainment.
Ralls County	.....	Unclassifiable/Attainment.
Randolph County	.....	Unclassifiable/Attainment.
Ray County	.....	Unclassifiable/Attainment.
Reynolds County	.....	Unclassifiable/Attainment.
Ripley County	.....	Unclassifiable/Attainment.
St. Clair County	.....	Unclassifiable/Attainment.
St. Genevieve County	.....	Unclassifiable/Attainment.
St. Francois County	.....	Unclassifiable/Attainment.
Saline County	.....	Unclassifiable/Attainment.
Schuyler County	.....	Unclassifiable/Attainment.
Scotland County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Shannon County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Stoddard County	.....	Unclassifiable/Attainment.
Stone County	.....	Unclassifiable/Attainment.
Sullivan County	.....	Unclassifiable/Attainment.
Taney County	.....	Unclassifiable/Attainment.
Texas County	.....	Unclassifiable/Attainment.
Vernon County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Webster County	.....	Unclassifiable/Attainment.
Worth County	.....	Unclassifiable/Attainment.
Wright County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 28. In § 81.327, the table entitled ''Montana—PM2.5'' is added to the end of the section to read as follows:

§ 81.327 Montana.

* * * * *

MONTANA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Libby, MT:		
Lincoln County (part)	.....	Nonattainment.
The area bounded by lines from Universal Transverse Mercador Zone 11 (North American Datum 1983) coordinates beginning at 600,000mE, 5,370,000mN east to 620,000mE, 5370,000mN south to 620,000mE, 5340,000mN west to 600,000mE, 5,340,000mN north to 600,000mE, 5,370,000mN		
Rest of State:		
Beaverhead County	.....	Unclassifiable/Attainment.
Big Horn County	.....	Unclassifiable/Attainment.
Blaine County	.....	Unclassifiable/Attainment.
Broadwater County	.....	Unclassifiable/Attainment.
Carbon County	.....	Unclassifiable/Attainment.
Carter County	.....	Unclassifiable/Attainment.
Cascade County	.....	Unclassifiable/Attainment.
Chouteau County	.....	Unclassifiable/Attainment.
Custer County	.....	Unclassifiable/Attainment.
Daniels County	.....	Unclassifiable/Attainment.
Dawson County	.....	Unclassifiable/Attainment.
Deer Lodge County	.....	Unclassifiable/Attainment.
Fallon County	.....	Unclassifiable/Attainment.
Fergus County	.....	Unclassifiable/Attainment.
Flathead County	.....	Unclassifiable/Attainment.
Gallatin County	.....	Unclassifiable/Attainment.
Garfield County	.....	Unclassifiable/Attainment.
Glacier County	.....	Unclassifiable/Attainment.

MONTANA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Golden Valley County	.....	Unclassifiable/Attainment.
Granite County	.....	Unclassifiable/Attainment.
Hill County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Judith Basin County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.
Lewis and Clark County	.....	Unclassifiable/Attainment.
Liberty County	.....	Unclassifiable/Attainment.
Lincoln County (remainder)	.....	Unclassifiable/Attainment.
McCone County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Meagher County	.....	Unclassifiable/Attainment.
Mineral County	.....	Unclassifiable/Attainment.
Missoula County	.....	Unclassifiable/Attainment.
Musselshell County	.....	Unclassifiable/Attainment.
Park County	.....	Unclassifiable/Attainment.
Petroleum County	.....	Unclassifiable/Attainment.
Phillips County	.....	Unclassifiable/Attainment.
Pondera County	.....	Unclassifiable/Attainment.
Powder River County	.....	Unclassifiable/Attainment.
Powell County	.....	Unclassifiable/Attainment.
Prairie County	.....	Unclassifiable/Attainment.
Ravalli County	.....	Unclassifiable/Attainment.
Richland County	.....	Unclassifiable/Attainment.
Roosevelt County	.....	Unclassifiable/Attainment.
Rosebud County	.....	Unclassifiable/Attainment.
Sanders County	.....	Unclassifiable/Attainment.
Sheridan County	.....	Unclassifiable/Attainment.
Silver Bow County	.....	Unclassifiable/Attainment.
Stillwater County	.....	Unclassifiable/Attainment.
Sweet Grass County	.....	Unclassifiable/Attainment.
Teton County	.....	Unclassifiable/Attainment.
Toole County	.....	Unclassifiable/Attainment.
Treasure County	.....	Unclassifiable/Attainment.
Valley County	.....	Unclassifiable/Attainment.
Wheatland County	.....	Unclassifiable/Attainment.
Wibaux County	.....	Unclassifiable/Attainment.
Yellowstone County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 29. In § 81.328, the table entitled ''Nebraska—PM2.5'' is added to the end of the section to read as follows:

§ 81.328 Nebraska.

* * * * *

NEBRASKA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Adams County	.....	Unclassifiable/Attainment.
Antelope County	.....	Unclassifiable/Attainment.
Arthur County	.....	Unclassifiable/Attainment.
Banner County	.....	Unclassifiable/Attainment.
Blaine County	.....	Unclassifiable/Attainment.
Boone County	.....	Unclassifiable/Attainment.
Box Butte County	.....	Unclassifiable/Attainment.
Boyd County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Buffalo County	.....	Unclassifiable/Attainment.
Burt County	.....	Unclassifiable/Attainment.
Butler County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Cedar County	.....	Unclassifiable/Attainment.
Chase County	.....	Unclassifiable/Attainment.
Cherry County	.....	Unclassifiable/Attainment.

NEBRASKA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Cheyenne County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Colfax County	.....	Unclassifiable/Attainment.
Cuming County	.....	Unclassifiable/Attainment.
Custer County	.....	Unclassifiable/Attainment.
Dakota County	.....	Unclassifiable/Attainment.
Dawes County	.....	Unclassifiable/Attainment.
Dawson County	.....	Unclassifiable/Attainment.
Deuel County	.....	Unclassifiable/Attainment.
Dixon County	.....	Unclassifiable/Attainment.
Dodge County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Dundy County	.....	Unclassifiable/Attainment.
Fillmore County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Frontier County	.....	Unclassifiable/Attainment.
Furnas County	.....	Unclassifiable/Attainment.
Gage County	.....	Unclassifiable/Attainment.
Garden County	.....	Unclassifiable/Attainment.
Garfield County	.....	Unclassifiable/Attainment.
Gosper County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Greeley County	.....	Unclassifiable/Attainment.
Hall County	.....	Unclassifiable/Attainment.
Hamilton County	.....	Unclassifiable/Attainment.
Harlan County	.....	Unclassifiable/Attainment.
Hayes County	.....	Unclassifiable/Attainment.
Hitchcock County	.....	Unclassifiable/Attainment.
Holt County	.....	Unclassifiable/Attainment.
Hooker County	.....	Unclassifiable/Attainment.
Howard County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Kearney County	.....	Unclassifiable/Attainment.
Keith County	.....	Unclassifiable/Attainment.
Keya Paha County	.....	Unclassifiable/Attainment.
Kimball County	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
Lancaster County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
Loup County	.....	Unclassifiable/Attainment.
McPherson County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Merrick County	.....	Unclassifiable/Attainment.
Morrill County	.....	Unclassifiable/Attainment.
Nance County	.....	Unclassifiable/Attainment.
Nemaha County	.....	Unclassifiable/Attainment.
Nuckolls County	.....	Unclassifiable/Attainment.
Otoe County	.....	Unclassifiable/Attainment.
Pawnee County	.....	Unclassifiable/Attainment.
Perkins County	.....	Unclassifiable/Attainment.
Phelps County	.....	Unclassifiable/Attainment.
Pierce County	.....	Unclassifiable/Attainment.
Platte County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Red Willow County	.....	Unclassifiable/Attainment.
Richardson County	.....	Unclassifiable/Attainment.
Rock County	.....	Unclassifiable/Attainment.
Saline County	.....	Unclassifiable/Attainment.
Sarpy County	.....	Unclassifiable/Attainment.
Saunders County	.....	Unclassifiable/Attainment.
Scotts Bluff County	.....	Unclassifiable/Attainment.
Seward County	.....	Unclassifiable/Attainment.
Sheridan County	.....	Unclassifiable/Attainment.
Sherman County	.....	Unclassifiable/Attainment.
Sioux County	.....	Unclassifiable/Attainment.
Stanton County	.....	Unclassifiable/Attainment.
Thayer County	.....	Unclassifiable/Attainment.
Thomas County	.....	Unclassifiable/Attainment.

NEBRASKA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Thurston County	.....	Unclassifiable/Attainment.
Valley County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Webster County	.....	Unclassifiable/Attainment.
Wheeler County	.....	Unclassifiable/Attainment.
York County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 30. In § 81.329, the table entitled ''Nevada.—PM2.5'' is added to the end of the section to read as follows:

§ 81.329 Nevada.

* * * * *

NEVADA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide [2]	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.
[2] Statewide refers to hydrographic areas as shown on the State of Nevada Division of Water Resources' map titled ''Water Resources and Inter-basin Flows'' (September 1971), as revised to include a division of Carson Desert (area 101) into two areas, a smaller area 101 and area 101A, and a division of Boulder Flat (area 61) into an Upper Unit 61 and a Lower Unit 61. See also 67 FR 12474 (March 19, 2002).

■ 31. In § 81.330, the table entitled ''New Hampshire.—PM2.5'' is added to the end of the section to read as follows:

§ 81.330 New Hampshire.

* * * * *

NEW HAMPSHIRE.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Belknap County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Cheshire County	.....	Unclassifiable/Attainment.
Coos County	.....	Unclassifiable/Attainment.
Grafton County	.....	Unclassifiable/Attainment.
Hillsborough County	.....	Unclassifiable/Attainment.
Merrimack County	.....	Unclassifiable/Attainment.
Rockingham County	.....	Unclassifiable/Attainment.
Strafford County	.....	Unclassifiable/Attainment.
Sullivan County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 32. In § 81.331, the table entitled ''New Jersey.—PM2.5'' is added to the end of the section to read as follows:

§ 81.331 New Jersey.

* * * * *

NEW JERSEY.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
New York–N. New Jersey–Long Island, NY-NJ-CT:		
Bergen County	.....	Nonattainment.
Essex County	.....	Nonattainment.
Hudson County	.....	Nonattainment.

NEW JERSEY.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Mercer County	.....	Nonattainment.
Middlesex County	.....	Nonattainment.
Monmouth County	.....	Nonattainment.
Morris County	.....	Nonattainment.
Passaic County	.....	Nonattainment.
Somerset County	.....	Nonattainment.
Union County	.....	Nonattainment.
Philadelphia–Wilmington, PA-NJ-DE:		
Burlington County	.....	Nonattainment.
Camden County	.....	Nonattainment.
Gloucester County	.....	Nonattainment.
New York–N. New Jersey–Long Island, NY-NJ-CT:		
Hunterdon County	.....	Unclassifiable/Attainment.
Sussex County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Atlantic City, NJ:		
Atlantic County	.....	Unclassifiable/Attainment.
Cape May County	.....	Unclassifiable/Attainment.
Cumberland County	.....	Unclassifiable/Attainment.
Ocean County	.....	Unclassifiable/Attainment.
Salem County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 33. In § 81.332, the table entitled ''New Mexico.—PM25'' is added to the end of the section to read as follows:

§ 81.332 New Mexico.

* * * * *

NEW MEXICO.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 012 New Mexico-Southern Border Intrastate:		
Grant County	.....	Unclassifiable/Attainment.
Hidalgo County	.....	Unclassifiable/Attainment.
Luna County	.....	Unclassifiable/Attainment.
AQCR 014 Four Corners Interstate (see 40 CFR 81.121):		
McKinley County (part)	.....	Unclassifiable/Attainment.
Río Arriba County (part)	.....	Unclassifiable/Attainment.
Sandoval County (part)	.....	Unclassifiable/Attainment.
San Juan County	.....	Unclassifiable/Attainment.
Valencia County (part)	.....	Unclassifiable/Attainment.
AQCR 152 Albuquerque-Mid Rio Grande Intrastate:		
Bernalillo County	.....	Unclassifiable/Attainment.
Sandoval County (part) see 40 CFR 81.83	.....	Unclassifiable/Attainment.
Valencia County (part) see 40 CFR 81.83	.....	Unclassifiable/Attainment.
AQCR 153 El Paso-Las Cruces-Alamogordo:		
Doña Ana County (part)	.....	Unclassifiable/Attainment.
(Sunland Park Area) The area bounded by the New Mexico-Texas State line on the east, New Mexico-Mexico international line on the south, the range 3E-Range 2E line on the west, and the N3200 latitude line on the north.		
Doña Ana County (remainder)	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Otero County	.....	Unclassifiable/Attainment.
Sierra County	.....	Unclassifiable/Attainment.
AQCR 154 Northeastern Plains Intrastate:		
Colfax County	.....	Unclassifiable/Attainment.
Guadalupe County	.....	Unclassifiable/Attainment.
Harding County	.....	Unclassifiable/Attainment.
Mora County	.....	Unclassifiable/Attainment.
San Miguel County	.....	Unclassifiable/Attainment.
Torrance County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
AQCR 155 Pecos-Permian Basin Intrastate:		
Chaves County	.....	Unclassifiable/Attainment.
Curry County	.....	Unclassifiable/Attainment.

NEW MEXICO.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
De Baca County	.....	Unclassifiable/Attainment.
Eddy County	.....	Unclassifiable/Attainment.
Lea County	.....	Unclassifiable/Attainment.
Quay County	.....	Unclassifiable/Attainment.
Roosevelt County	.....	Unclassifiable/Attainment.
AQCR 156 SW Mountains-Augustine Plains:		
Catron County	.....	Unclassifiable/Attainment.
Cibola County	.....	Unclassifiable/Attainment.
McKinley County (part) see 40 CFR 81.241	.....	Unclassifiable/Attainment.
Socorro County	.....	Unclassifiable/Attainment.
Valencia County (part) see 40 CFR 81.241	.....	Unclassifiable/Attainment.
AQCR 157 Upper Rio Grande Valley Intrastate:		
Los Alamos County	.....	Unclassifiable/Attainment.
Río Arriba County (part) see 40 CFR 81.239	.....	Unclassifiable/Attainment.
Santa Fe County	.....	Unclassifiable/Attainment.
Taos County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 34. In § 81.333, the table entitled ''New York.—PM2.5'' is added to the end of the section to read as follows:

§ 81.333 New York.

* * * * *

NEW YORK.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
New York–N. New Jersey-Long Island, NY-NJ-CT:		
Bronx County	.....	Nonattainment.
Kings County	.....	Nonattainment.
Nassau County	.....	Nonattainment.
New York County	.....	Nonattainment.
Orange County	.....	Nonattainment.
Queens County	.....	Nonattainment.
Richmond County	.....	Nonattainment.
Rockland County	.....	Nonattainment.
Suffolk County	.....	Nonattainment.
Westchester County	.....	Nonattainment.
AQCR 158 Central New York Intrastate (remainder of):		
Cortland County	.....	Unclassifiable/Attainment.
Herkimer County	.....	Unclassifiable/Attainment.
Lewis County	.....	Unclassifiable/Attainment.
Oneida County	.....	Unclassifiable/Attainment.
AQCR 159 Champlain Valley Interstate (remainder of):		
Clinton County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Hamilton County	.....	Unclassifiable/Attainment.
St. Lawrence County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
AQCR 160 Finger Lake Intrastate:		
Seneca County	.....	Unclassifiable/Attainment.
Wyoming County	.....	Unclassifiable/Attainment.
Yates County	.....	Unclassifiable/Attainment.
AQCR 161 Hudson Valley Intrastate (remainder of):		
Columbia County	.....	Unclassifiable/Attainment.
Fulton County	.....	Unclassifiable/Attainment.
Ulster County	.....	Unclassifiable/Attainment.
AQCR 163 Southern Tier East Intrastate:		
Broome County	.....	Unclassifiable/Attainment.
Chenango County	.....	Unclassifiable/Attainment.
Delaware County	.....	Unclassifiable/Attainment.
Otsego County	.....	Unclassifiable/Attainment.
Sullivan County	.....	Unclassifiable/Attainment.
Tioga County	.....	Unclassifiable/Attainment.
AQCR 164 Southern Tier West Intrastate:		
Allegany County	.....	Unclassifiable/Attainment.

NEW YORK.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Cattaraugus County	.....	Unclassifiable/Attainment.
Chemung County	.....	Unclassifiable/Attainment.
Schuyler County	.....	Unclassifiable/Attainment.
Steuben County	.....	Unclassifiable/Attainment.
Tompkins County	.....	Unclassifiable/Attainment.
Albany-Schenectady-Troy, NY:		
Albany County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Rensselaer County	.....	Unclassifiable/Attainment.
Saratoga County	.....	Unclassifiable/Attainment.
Schenectady County	.....	Unclassifiable/Attainment.
Schoharie County	.....	Unclassifiable/Attainment.
Buffalo-Niagara Falls, NY:		
Erie County	.....	Unclassifiable/Attainment.
Niagara County	.....	Unclassifiable/Attainment.
Essex County, NY:		
Essex County	.....	Unclassifiable/Attainment.
Jamestown, NY:		
Chautauqua County	.....	Unclassifiable/Attainment.
Jefferson County, NY:		
Jefferson County	.....	Unclassifiable/Attainment.
Poughkeepsie, NY:		
Dutchess County	.....	Unclassifiable/Attainment.
Putnam County	.....	Unclassifiable/Attainment.
Rochester, NY:		
Genesee County	.....	Unclassifiable/Attainment.
Livingston County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Ontario County	.....	Unclassifiable/Attainment.
Orleans County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Syracuse, NY:		
Cayuga County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Onondaga County	.....	Unclassifiable/Attainment.
Oswego County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 35. In § 81334, the table entitled ''North Carolina.—PM25'' is added to the end of the section to read as follows:

§ 81.334 North Carolina.

* * * * *

NORTH CAROLINA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Greensboro-Winston Salem-High Point, NC:		
Davidson County	.....	Nonattainment.
Guilford County	.....	Nonattainment.
Hickory-Morganton-Lenoir, NC:		
Catawba County	.....	Nonattainment.
Rest of State:		
Alamance County	.....	Unclassifiable/Attainment.
Alexander County	.....	Unclassifiable/Attainment.
Alleghany County	.....	Unclassifiable/Attainment.
Anson County	.....	Unclassifiable/Attainment.
Ashe County	.....	Unclassifiable/Attainment.
Avery County	.....	Unclassifiable/Attainment.
Beaufort County	.....	Unclassifiable/Attainment.
Bertie County	.....	Unclassifiable/Attainment.
Bladen County	.....	Unclassifiable/Attainment.
Brunswick County	.....	Unclassifiable/Attainment.
Buncombe County	.....	Unclassifiable/Attainment.
Burke County	.....	Unclassifiable/Attainment.

NORTH CAROLINA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Cabarrus County	.....	Unclassifiable/Attainment.
Caldwell County	.....	Unclassifiable/Attainment.
Camden County	.....	Unclassifiable/Attainment.
Carteret County	.....	Unclassifiable/Attainment.
Caswell County	.....	Unclassifiable/Attainment.
Chatham County	.....	Unclassifiable/Attainment.
Cherokee County	.....	Unclassifiable/Attainment.
Chowan County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Cleveland County	.....	Unclassifiable/Attainment.
Columbus County	.....	Unclassifiable/Attainment.
Craven County	.....	Unclassifiable/Attainment.
Cumberland County	.....	Unclassifiable/Attainment.
Currituck County	.....	Unclassifiable/Attainment.
Dare County	.....	Unclassifiable/Attainment.
Davie County	.....	Unclassifiable/Attainment.
Duplin County	.....	Unclassifiable/Attainment.
Durham County	.....	Unclassifiable/Attainment.
Edgecombe County	.....	Unclassifiable/Attainment.
Forsyth County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Gaston County	.....	Unclassifiable/Attainment.
Gates County	.....	Unclassifiable/Attainment.
Graham County	.....	Unclassifiable/Attainment.
Granville County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Halifax County	.....	Unclassifiable/Attainment.
Harnett County	.....	Unclassifiable/Attainment.
Haywood County	.....	Unclassifiable/Attainment.
Henderson County	.....	Unclassifiable/Attainment.
Hertford County	.....	Unclassifiable/Attainment.
Hoke County	.....	Unclassifiable/Attainment.
Hyde County	.....	Unclassifiable/Attainment.
Iredell County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Johnston County	.....	Unclassifiable/Attainment.
Jones County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Lenoir County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
McDowell County	.....	Unclassifiable/Attainment.
Macon County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Martin County	.....	Unclassifiable/Attainment.
Mecklenburg County	.....	Unclassifiable/Attainment.
Mitchell County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Moore County	.....	Unclassifiable/Attainment.
Nash County	.....	Unclassifiable/Attainment.
New Hanover County	.....	Unclassifiable/Attainment.
Northampton County	.....	Unclassifiable/Attainment.
Onslow County	.....	Unclassifiable/Attainment.
Orange County	.....	Unclassifiable/Attainment.
Pamlico County	.....	Unclassifiable/Attainment.
Pasquotank County	.....	Unclassifiable/Attainment.
Pender County	.....	Unclassifiable/Attainment.
Perquimans County	.....	Unclassifiable/Attainment.
Person County	.....	Unclassifiable/Attainment.
Pitt County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Randolph County	.....	Unclassifiable/Attainment.
Richmond County	.....	Unclassifiable/Attainment.
Robeson County	.....	Unclassifiable/Attainment.
Rockingham County	.....	Unclassifiable/Attainment.
Rowan County	.....	Unclassifiable/Attainment.
Rutherford County	.....	Unclassifiable/Attainment.
Sampson County	.....	Unclassifiable/Attainment.
Scotland County	.....	Unclassifiable/Attainment.
Stanly County	.....	Unclassifiable/Attainment.
Stokes County	.....	Unclassifiable/Attainment.

NORTH CAROLINA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Surry County	.....	Unclassifiable/Attainment.
Swain County	.....	Unclassifiable/Attainment.
Transylvania County	.....	Unclassifiable/Attainment.
Tyrrell County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Vance County	.....	Unclassifiable/Attainment.
Wake County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Watauga County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Wilkes County	.....	Unclassifiable/Attainment.
Wilson County	.....	Unclassifiable/Attainment.
Yadkin County	.....	Unclassifiable/Attainment.
Yancey County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 36. In § 81.335, the table entitled ''North Dakota.—PM2.5'' is added to the end of the section to read as follows:

§ 81.335 North Dakota

* * * * *

NORTH DAKOTA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 130 Metropolitan Fargo-Moorhead Interstate:		
Cass County	.....	Unclassifiable/Attainment.
Rest of State, AQCR 172:		
Adams County	.....	Unclassifiable/Attainment.
Barnes County	.....	Unclassifiable/Attainment.
Benson County	.....	Unclassifiable/Attainment.
Billings County	.....	Unclassifiable/Attainment.
Bottineau County	.....	Unclassifiable/Attainment.
Bowman County	.....	Unclassifiable/Attainment.
Burke County	.....	Unclassifiable/Attainment.
Burleigh County	.....	Unclassifiable/Attainment.
Cavalier County	.....	Unclassifiable/Attainment.
Dickey County	.....	Unclassifiable/Attainment.
Divide County	.....	Unclassifiable/Attainment.
Dunn County	.....	Unclassifiable/Attainment.
Eddy County	.....	Unclassifiable/Attainment.
Emmons County	.....	Unclassifiable/Attainment.
Foster County	.....	Unclassifiable/Attainment.
Golden Valley County	.....	Unclassifiable/Attainment.
Grand Forks County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Griggs County	.....	Unclassifiable/Attainment.
Hettinger County	.....	Unclassifiable/Attainment.
Kidder County	.....	Unclassifiable/Attainment.
LaMoure County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
McHenry County	.....	Unclassifiable/Attainment.
McIntosh County	.....	Unclassifiable/Attainment.
McKenzie County	.....	Unclassifiable/Attainment.
McLean County	.....	Unclassifiable/Attainment.
Mercer County	.....	Unclassifiable/Attainment.
Morton County	.....	Unclassifiable/Attainment.
Mountrail County	.....	Unclassifiable/Attainment.
Nelson County	.....	Unclassifiable/Attainment.
Oliver County	.....	Unclassifiable/Attainment.
Pembina County	.....	Unclassifiable/Attainment.
Pierce County	.....	Unclassifiable/Attainment.
Ramsey County	.....	Unclassifiable/Attainment.
Ransom County	.....	Unclassifiable/Attainment.
Renville County	.....	Unclassifiable/Attainment.
Richland County	.....	Unclassifiable/Attainment.

NORTH DAKOTA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Rolette County	.....	Unclassifiable/Attainment.
Sargent County	.....	Unclassifiable/Attainment.
Sheridan County	.....	Unclassifiable/Attainment.
Sioux County	.....	Unclassifiable/Attainment.
Slope County	.....	Unclassifiable/Attainment.
Stark County	.....	Unclassifiable/Attainment.
Steele County	.....	Unclassifiable/Attainment.
Stutsman County	.....	Unclassifiable/Attainment.
Towner County	.....	Unclassifiable/Attainment.
Traill County	.....	Unclassifiable/Attainment.
Walsh County	.....	Unclassifiable/Attainment.
Ward County	.....	Unclassifiable/Attainment.
Wells County	.....	Unclassifiable/Attainment.
Williams County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 37. In § 81.336, the table entitled ''Ohio.—PM2.5'' is added to the end of the section to read as follows:

§ 81.336 Ohio.

* * * * *

OHIO.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Canton-Massillon, OH:		
Stark County	.....	Nonattainment.
Cincinnati-Hamilton, OH-KY-IN:		
Butler County	.....	Nonattainment.
Clermont County	.....	Nonattainment.
Hamilton County	.....	Nonattainment.
Warren County	.....	Nonattainment.
Cleveland-Akron-Lorain, OH:		
Ashtabula County (part)	.....	Nonattainment.
Ashtabula Township	.....	
Cuyahoga County	.....	Nonattainment.
Lake County	.....	Nonattainment.
Lorain County	.....	Nonattainment.
Medina County	.....	Nonattainment.
Portage County	.....	Nonattainment.
Summit County	.....	Nonattainment.
Columbus, OH:		
Coshocton County (part)	.....	Nonattainment.
Franklin Township	.....	
Delaware County	.....	Nonattainment.
Fairfield County	.....	Nonattainment.
Franklin County	.....	Nonattainment.
Licking County	.....	Nonattainment.
Dayton-Springfield, OH:		
Clark County	.....	Nonattainment.
Greene County	.....	Nonattainment.
Montgomery County	.....	Nonattainment.
Huntington-Ashland, WV-KY-OH:		
Adams County (part)	.....	Nonattainment.
Monroe Township, Sprigg Township	.....	
Gallia County (part)	.....	Nonattainment.
Addison Township, Cheshire Township	.....	
Lawrence County	.....	Nonattainment.
Scioto County	.....	Nonattainment.
Parkersburg-Marietta, WV-OH:		
Washington County	.....	Nonattainment.
Steubenville-Weirton, OH-WV:		
Jefferson County	.....	Nonattainment.
Toledo, OH:		
Lucas County	.....	Nonattainment.
Wood County	.....	Nonattainment.
Wheeling, WV-OH:		

OHIO.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Belmont County	.....	Nonattainment.
Youngstown-Warren-Sharon, OH-PA:		
Columbiana County	.....	Nonattainment.
Mahoning County	.....	Nonattainment.
Trumbull County	.....	Nonattainment.
Rest of State:		
Adams County (remainder)	.....	Unclassifiable/Attainment.
Allen County	.....	Unclassifiable/Attainment.
Ashland County	.....	Unclassifiable/Attainment.
Ashtabula County (remainder)	.....	Unclassifiable/Attainment.
Athens County	.....	Unclassifiable/Attainment.
Auglaize County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Champaign County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Coshocton County (remainder)	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Darke County	.....	Unclassifiable/Attainment.
Defiance County	.....	Unclassifiable/Attainment.
Erie County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Fulton County	.....	Unclassifiable/Attainment.
Gallia County (remainder)	.....	Unclassifiable/Attainment.
Geauga County	.....	Unclassifiable/Attainment.
Guernsey County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Hardin County	.....	Unclassifiable/Attainment.
Harrison County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Highland County	.....	Unclassifiable/Attainment.
Hocking County	.....	Unclassifiable/Attainment.
Holmes County	.....	Unclassifiable/Attainment.
Huron County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Meigs County	.....	Unclassifiable/Attainment.
Mercer County	.....	Unclassifiable/Attainment.
Miami County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Morrow County	.....	Unclassifiable/Attainment.
Muskingum County	.....	Unclassifiable/Attainment.
Noble County	.....	Unclassifiable/Attainment.
Ottawa County	.....	Unclassifiable/Attainment.
Paulding County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pickaway County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Preble County	.....	Unclassifiable/Attainment.
Putnam County	.....	Unclassifiable/Attainment.
Richland County	.....	Unclassifiable/Attainment.
Ross County	.....	Unclassifiable/Attainment.
Sandusky County	.....	Unclassifiable/Attainment.
Seneca County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Tuscarawas County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Van Wert County	.....	Unclassifiable/Attainment.
Vinton County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Williams County	.....	Unclassifiable/Attainment.
Wyandot County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 38. In § 81.337, the table entitled ''Oklahoma—PM2.5'' is added to the end of the section to read as follows:

§ 81.337 Oklahoma.

* * * * *

OKLAHOMA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 017 Metropolitan Fort Smith Interstate:		
Adair County	.....	Unclassifiable/Attainment.
Cherokee County	.....	Unclassifiable/Attainment.
Le Flore County	.....	Unclassifiable/Attainment.
Sequoyah County	.....	Unclassifiable/Attainment.
AQCR 022 Shreveport-Texarkana-Tyler Intrastate:		
McCurtain County	.....	Unclassifiable/Attainment.
AQCR 184 Central Oklahoma Intrastate (part):		
Cleveland County	.....	Unclassifiable/Attainment.
Oklahoma County	.....	Unclassifiable/Attainment.
AQCR 184 Central Oklahoma Intrastate (remainder of):		
Canadian County	.....	Unclassifiable/Attainment.
Grady County	.....	Unclassifiable/Attainment.
Kingfisher County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
McClain County	.....	Unclassifiable/Attainment.
Pottawatomie County	.....	Unclassifiable/Attainment.
AQCR 185 North Central Oklahoma Intrastate:	.....	
Garfield County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Kay County	.....	Unclassifiable/Attainment.
Noble County	.....	Unclassifiable/Attainment.
Payne County	.....	Unclassifiable/Attainment.
AQCR 186 Northeastern Oklahoma Intrastate:		
Craig County	.....	Unclassifiable/Attainment.
Creek County	.....	Unclassifiable/Attainment.
Delaware County	.....	Unclassifiable/Attainment.
Mayes County	.....	Unclassifiable/Attainment.
Muskogee County	.....	Unclassifiable/Attainment.
Nowata County	.....	Unclassifiable/Attainment.
Okmulgee County	.....	Unclassifiable/Attainment.
Osage County	.....	Unclassifiable/Attainment.
Ottawa County	.....	Unclassifiable/Attainment.
Pawnee County	.....	Unclassifiable/Attainment.
Rogers County	.....	Unclassifiable/Attainment.
Tulsa County	.....	Unclassifiable/Attainment.
Wagoner County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
AQCR 187 Northwestern Oklahoma Intrastate:	.....	
Alfalfa County	.....	Unclassifiable/Attainment.
Beaver County	.....	Unclassifiable/Attainment.
Blaine County	.....	Unclassifiable/Attainment.
Cimarron County	.....	Unclassifiable/Attainment.
Custer County	.....	Unclassifiable/Attainment.
Dewey County	.....	Unclassifiable/Attainment.
Ellis County	.....	Unclassifiable/Attainment.
Harper County	.....	Unclassifiable/Attainment.
Major County	.....	Unclassifiable/Attainment.
Roger Mills County	.....	Unclassifiable/Attainment.
Texas County	.....	Unclassifiable/Attainment.
Woods County	.....	Unclassifiable/Attainment.
Woodward County	.....	Unclassifiable/Attainment.
AQCR 188 Southeastern Oklahoma Intrastate:		
Atoka County	.....	Unclassifiable/Attainment.
Bryan County	.....	Unclassifiable/Attainment.
Carter County	.....	Unclassifiable/Attainment.
Choctaw County	.....	Unclassifiable/Attainment.
Coal County	.....	Unclassifiable/Attainment.
Garvin County	.....	Unclassifiable/Attainment.
Haskell County	.....	Unclassifiable/Attainment.
Hughes County	.....	Unclassifiable/Attainment.
Johnston County	.....	Unclassifiable/Attainment.
Latimer County	.....	Unclassifiable/Attainment.
Love County	.....	Unclassifiable/Attainment.
McIntosh County	.....	Unclassifiable/Attainment.

OKLAHOMA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Marshall County	.....	Unclassifiable/Attainment.
Murray County	.....	Unclassifiable/Attainment.
Okfuskee County	.....	Unclassifiable/Attainment.
Pittsburg County	.....	Unclassifiable/Attainment.
Pontotoc County	.....	Unclassifiable/Attainment.
Pushmataha County	.....	Unclassifiable/Attainment.
Seminole County	.....	Unclassifiable/Attainment.
AQCR 189 Southwestern Oklahoma Intrastate:		
Beckham County	.....	Unclassifiable/Attainment.
Caddo County	.....	Unclassifiable/Attainment.
Comanche County	.....	Unclassifiable/Attainment.
Cotton County	.....	Unclassifiable/Attainment.
Greer County	.....	Unclassifiable/Attainment.
Harmon County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Kiowa County	.....	Unclassifiable/Attainment.
Stephens County	.....	Unclassifiable/Attainment.
Tillman County	.....	Unclassifiable/Attainment.
Washita County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 39. In § 81.338, the table entitled ''Oregon.—PM2.5'' is added to the end of the section to read as follows:

§ 81.338 Oregon.

* * * * *

OREGON.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Portland-Vancouver AQMA:		
(Air Quality Maintenance Area)		
Clackamas County (part)	.....	Unclassifiable/Attainment.
Multnomah County (part)	.....	Unclassifiable/Attainment.
Washington County (part)	.....	Unclassifiable/Attainment.
Salem Area:		
(Salem Area Transportation Study):		
Marion County (part)	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
AQCR 190 Central Oregon Intrastate (remainder of):		
Crook County	.....	Unclassifiable/Attainment.
Deschutes County	.....	Unclassifiable/Attainment.
Hood River County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Klamath County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.
Sherman County	.....	Unclassifiable/Attainment.
Wasco County	.....	Unclassifiable/Attainment.
AQCR 191 Eastern Oregon Intrastate:		
Baker County	.....	Unclassifiable/Attainment.
Gilliam County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Harney County	.....	Unclassifiable/Attainment.
Malheur County	.....	Unclassifiable/Attainment.
Morrow County	.....	Unclassifiable/Attainment.
Umatilla County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Wallowa County	.....	Unclassifiable/Attainment.
Wheeler County	.....	Unclassifiable/Attainment.
AQCR 192 Northwest Oregon Intrastate:		
Clatsop County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Tillamook County	.....	Unclassifiable/Attainment.
AQCR 193 Portland Interstate (part):		
Lane County (part)	.....	Unclassifiable/Attainment.

OREGON.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Eugene Springfield Air Quality Maintenance Area		
AQCR 193 Portland Interstate (remainder of):		
Benton County	.....	Unclassifiable/Attainment.
Clackamas County (remainder)	.....	Unclassifiable/Attainment.
Columbia County	.....	Unclassifiable/Attainment.
Lane County (remainder)	.....	Unclassifiable/Attainment.
Linn County	.....	Unclassifiable/Attainment.
Marion County (part)	.....	Unclassifiable/Attainment.
The area outside the Salem Area Transportation Study		
Multnomah County (remainder)	.....	Unclassifiable/Attainment.
Polk County (part)	.....	Unclassifiable/Attainment.
The area outside the Salem Area Transportation Study		
Washington County (remainder)	.....	Unclassifiable/Attainment.
Yamhill County	.....	Unclassifiable/Attainment.
AQCR 194 Southwest Oregon Intrastate (part):		
Jackson County (part)	.....	Unclassifiable/Attainment.
Medford-Ashland Air Quality Maintenance Area		
AQCR 194 Southwest Oregon Intrastate (remainder of):		
Coos County	.....	Unclassifiable/Attainment.
Curry County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Jackson County (remainder)	.....	Unclassifiable/Attainment.
Josephine County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 40. In § 81.339, the table entitled ''Pennsylvania.—PM2.5'' is added to the end of the section to read as follows:

§ 81.339 Pennsylvania.

* * * * *

PENNSYLVANIA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Harrisburg-Lebanon-Carlisle, PA:		
Cumberland County	.....	Nonattainment.
Dauphin County	.....	Nonattainment.
Lebanon County	.....	Nonattainment.
Johnstown, PA:		
Cambria County	.....	Nonattainment.
Indiana County (part)	.....	Nonattainment.
Townships of West Wheatfield, Center, East Wheatfield, and Armagh Borough and Homer City Borough		
Lancaster, PA:		
Lancaster County	.....	Nonattainment.
Liberty-Clairton, PA:		
Allegheny County (part)	.....	Nonattainment.
Lincoln Borough, Clairton City, Glassport Borough, Liberty Borough, Port Vue Borough		
Philadelphia-Wilmington, PA-NJ-DE:		
Bucks County	.....	Nonattainment.
Chester County	.....	Nonattainment.
Delaware County	.....	Nonattainment.
Montgomery County	.....	Nonattainment.
Philadelphia County	.....	Nonattainment.
Pittsburgh-Beaver Valley, PA:		
Allegheny County (remainder)	.....	Nonattainment.
Armstrong County (part)	.....	Nonattainment.
Elderton Borough and Plumcreek and Washington Townships		
Beaver County	.....	Nonattainment.
Butler County	.....	Nonattainment.
Greene County (part)	.....	Nonattainment.
Monongahela Township		
Lawrence County (part)	.....	Nonattainment.
Township of Taylor south of New Castle City		
Washington County	.....	Nonattainment.
Westmoreland County	.....	Nonattainment.

PENNSYLVANIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Reading, PA:		
Berks County	.....	Nonattainment.
York, PA:		
York County	.....	Nonattainment.
Youngstown-Warren-Sharon, OH-PA:		
Mercer County	.....	Nonattainment.
AQCR 151 Northeast Pennsylvania-Upper Delaware Valley Interstate:		
Bradford County	.....	Unclassifiable/Attainment.
Carbon County	.....	Unclassifiable/Attainment.
Lackawanna County	.....	Unclassifiable/Attainment.
Lehigh County	.....	Unclassifiable/Attainment.
Luzerne County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Northampton County	.....	Unclassifiable/Attainment.
Pike County	.....	Unclassifiable/Attainment.
Schuylkill County	.....	Unclassifiable/Attainment.
Sullivan County	.....	Unclassifiable/Attainment.
Susquehanna County	.....	Unclassifiable/Attainment.
Tioga County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Wyoming County	.....	Unclassifiable/Attainment.
AQCR 178 Northwest Pennsylvania-Youngstown Interstate:		
Cameron County	.....	Unclassifiable/Attainment.
Clarion County	.....	Unclassifiable/Attainment.
Clearfield County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Elk County	.....	Unclassifiable/Attainment.
Erie County	.....	Unclassifiable/Attainment.
Forest County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Lawrence County (remainder)	.....	Unclassifiable/Attainment.
McKean County	.....	Unclassifiable/Attainment.
Potter County	.....	Unclassifiable/Attainment.
Venango County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
AQCR 195 Central Pennsylvania Intrastate:		
Bedford County	.....	Unclassifiable/Attainment.
Blair County	.....	Unclassifiable/Attainment.
Centre County	.....	Unclassifiable/Attainment.
Clinton County	.....	Unclassifiable/Attainment.
Columbia County	.....	Unclassifiable/Attainment.
Fulton County	.....	Unclassifiable/Attainment.
Huntingdon County	.....	Unclassifiable/Attainment.
Juniata County	.....	Unclassifiable/Attainment.
Lycoming County	.....	Unclassifiable/Attainment.
Mifflin County	.....	Unclassifiable/Attainment.
Montour County	.....	Unclassifiable/Attainment.
Northumberland County	.....	Unclassifiable/Attainment.
Snyder County	.....	Unclassifiable/Attainment.
Somerset County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
AQCR 196 South Central Pennsylvania Intrastate:		
Adams County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
AQCR 197 Southwest Pennsylvania Intrastate:		
Armstrong County (remainder)	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Greene County (remainder)	.....	Unclassifiable/Attainment.
Indiana County (remainder)	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 41. In § 81.340, the table entitled ''Rhode Island.—PM2.5'' is added to the end of the section to read as follows:

§ 81.340 Rhode Island.

* * * * *

RHODE ISLAND.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Bristol County	.....	Unclassifiable/Attainment.
Kent County	.....	Unclassifiable/Attainment.
Newport County	.....	Unclassifiable/Attainment.
Providence County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 42. In § 81.341, the table entitled ''South Carolina.—PM2.5'' is added to the end of the section to read as follows:

§ 81.341 South Carolina.

* * * * *

SOUTH CAROLINA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Greenville-Spartanburg, SC:		
Anderson County	.....	Unclassifiable
Greenville County	.....	Unclassifiable
Spartanburg County	.....	Unclassifiable
Rest of State:		
Abbeville County	.....	Unclassifiable/Attainment.
Aiken County	.....	Unclassifiable/Attainment.
Allendale County	.....	Unclassifiable/Attainment.
Bamberg County	.....	Unclassifiable/Attainment.
Barnwell County	.....	Unclassifiable/Attainment.
Beaufort County	.....	Unclassifiable/Attainment.
Berkeley County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Charleston County	.....	Unclassifiable/Attainment.
Cherokee County	.....	Unclassifiable/Attainment.
Chester County	.....	Unclassifiable/Attainment.
Chesterfield County	.....	Unclassifiable/Attainment.
Clarendon County	.....	Unclassifiable/Attainment.
Colleton County	.....	Unclassifiable/Attainment.
Darlington County	.....	Unclassifiable/Attainment.
Dillon County	.....	Unclassifiable/Attainment.
Dorchester County	.....	Unclassifiable/Attainment.
Edgefield County	.....	Unclassifiable/Attainment.
Fairfield County	.....	Unclassifiable/Attainment.
Florence County	.....	Unclassifiable/Attainment.
Georgetown County	.....	Unclassifiable/Attainment.
Greenwood County	.....	Unclassifiable/Attainment.
Hampton County	.....	Unclassifiable/Attainment.
Horry County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Kershaw County	.....	Unclassifiable/Attainment.
Lancaster County	.....	Unclassifiable/Attainment.
Laurens County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Lexington County	.....	Unclassifiable/Attainment.
McCormick County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Marlboro County	.....	Unclassifiable/Attainment.
Newberry County	.....	Unclassifiable/Attainment.
Oconee County	.....	Unclassifiable/Attainment.
Orangeburg County	.....	Unclassifiable/Attainment.
Pickens County	.....	Unclassifiable/Attainment.
Richland County	.....	Unclassifiable/Attainment.
Saluda County	.....	Unclassifiable/Attainment.
Sumter County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Williamsburg County	.....	Unclassifiable/Attainment.
York County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.

[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 43. In § 81.342, the table entitled ''South Dakota.—PM2.5'' is added to the end of the section to read as follows:

§ 81.342 South Dakota.

* * * * *

SOUTH DAKOTA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Aurora County	.....	Unclassifiable/Attainment.
Beadle County	.....	Unclassifiable/Attainment.
Bennett County	.....	Unclassifiable/Attainment.
Bon Homme County	.....	Unclassifiable/Attainment.
Brookings County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Brule County	.....	Unclassifiable/Attainment.
Buffalo County	.....	Unclassifiable/Attainment.
Butte County	.....	Unclassifiable/Attainment.
Campbell County	.....	Unclassifiable/Attainment.
Charles Mix County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Codington County	.....	Unclassifiable/Attainment.
Corson County	.....	Unclassifiable/Attainment.
Custer County	.....	Unclassifiable/Attainment.
Davison County	.....	Unclassifiable/Attainment.
Day County	.....	Unclassifiable/Attainment.
Deuel County	.....	Unclassifiable/Attainment.
Dewey County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Edmunds County	.....	Unclassifiable/Attainment.
Fall River County	.....	Unclassifiable/Attainment.
Faulk County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Gregory County	.....	Unclassifiable/Attainment.
Haakon County	.....	Unclassifiable/Attainment.
Hamlin County	.....	Unclassifiable/Attainment.
Hand County	.....	Unclassifiable/Attainment.
Hanson County	.....	Unclassifiable/Attainment.
Harding County	.....	Unclassifiable/Attainment.
Hughes County	.....	Unclassifiable/Attainment.
Hutchinson County	.....	Unclassifiable/Attainment.
Hyde County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jerauld County	.....	Unclassifiable/Attainment.
Jones County	.....	Unclassifiable/Attainment.
Kingsbury County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Lyman County	.....	Unclassifiable/Attainment.
McCook County	.....	Unclassifiable/Attainment.
McPherson County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Meade County	.....	Unclassifiable/Attainment.
Mellette County	.....	Unclassifiable/Attainment.
Miner County	.....	Unclassifiable/Attainment.
Minnehaha County	.....	Unclassifiable/Attainment.
Moody County	.....	Unclassifiable/Attainment.
Pennington County	.....	Unclassifiable/Attainment.
Perkins County	.....	Unclassifiable/Attainment.
Potter County	.....	Unclassifiable/Attainment.
Roberts County	.....	Unclassifiable/Attainment.
Sanborn County	.....	Unclassifiable/Attainment.
Shannon County	.....	Unclassifiable/Attainment.
Spink County	.....	Unclassifiable/Attainment.
Stanley County	.....	Unclassifiable/Attainment.
Sully Count	.....	Unclassifiable/Attainment.
Todd County	.....	Unclassifiable/Attainment.
Tripp County	.....	Unclassifiable/Attainment.
Turner County	.....	Unclassifiable/Attainment.

SOUTH DAKOTA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Union County	.....	Unclassifiable/Attainment.
Walworth County	.....	Unclassifiable/Attainment.
Yankton County	.....	Unclassifiable/Attainment.
Ziebach County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 44. In § 81.343, the table entitled ''Tennessee.—PM2.5'' is added to the end of the section to read as follows:

§ 81.343 Tennessee.

* * * * *

TENNESSEE.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Chattanooga, TN-GA:		
Hamilton County	.....	Nonattainment.
Knoxville, TN:		
Anderson County	.....	Nonattainment.
Blount County	.....	Nonattainment.
Knox County	.....	Nonattainment.
Loudon County	.....	Nonattainment.
Roane County (part)	.....	Nonattainment.
The area described by U.S. Census 2000 block group identifier 47–145–0307–2.		
McMinn County, TN:		
McMinn County	.....	Unclassifiable
Rest of State:		
Bedford County	.....	Unclassifiable/Attainment.
Benton County	.....	Unclassifiable/Attainment.
Bledsoe County	.....	Unclassifiable/Attainment.
Bradley County	.....	Unclassifiable/Attainment.
Campbell County	.....	Unclassifiable/Attainment.
Cannon County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Carter County	.....	Unclassifiable/Attainment.
Cheatham County	.....	Unclassifiable/Attainment.
Chester County	.....	Unclassifiable/Attainment.
Claiborne County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Cocke County	.....	Unclassifiable/Attainment.
Coffee County	.....	Unclassifiable/Attainment.
Crockett County	.....	Unclassifiable/Attainment.
Cumberland County	.....	Unclassifiable/Attainment.
Davidson County	.....	Unclassifiable/Attainment.
Decatur County	.....	Unclassifiable/Attainment.
DeKalb County	.....	Unclassifiable/Attainment.
Dickson County	.....	Unclassifiable/Attainment.
Dyer County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Fentress County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Gibson County	.....	Unclassifiable/Attainment.
Giles County	.....	Unclassifiable/Attainment.
Grainger County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
Grundy County	.....	Unclassifiable/Attainment.
Hamblen County	.....	Unclassifiable/Attainment.
Hancock County	.....	Unclassifiable/Attainment.
Hardeman County	.....	Unclassifiable/Attainment.
Hardin County	.....	Unclassifiable/Attainment.
Hawkins County	.....	Unclassifiable/Attainment.
Haywood County	.....	Unclassifiable/Attainment.
Henderson County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Hickman County	.....	Unclassifiable/Attainment.
Houston County	.....	Unclassifiable/Attainment.
Humphreys County	.....	Unclassifiable/Attainment.

TENNESSEE.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Jackson County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Lake County	.....	Unclassifiable/Attainment.
Lauderdale County	.....	Unclassifiable/Attainment.
Lawrence County	.....	Unclassifiable/Attainment.
Lewis County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
McNairy County	.....	Unclassifiable/Attainment.
Macon County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Marshall County	.....	Unclassifiable/Attainment.
Maury County	.....	Unclassifiable/Attainment.
Meigs County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Moore County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Obion County	.....	Unclassifiable/Attainment.
Overton County	.....	Unclassifiable/Attainment.
Perry County	.....	Unclassifiable/Attainment.
Pickett County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Putnam County	.....	Unclassifiable/Attainment.
Rhea County	.....	Unclassifiable/Attainment.
Roane County (remainder)	.....	Unclassifiable/Attainment.
Robertson County	.....	Unclassifiable/Attainment.
Rutherford County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Sequatchie County	.....	Unclassifiable/Attainment.
Sevier County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Smith County	.....	Unclassifiable/Attainment.
Stewart County	.....	Unclassifiable/Attainment.
Sullivan County	.....	Unclassifiable/Attainment.
Sumner County	.....	Unclassifiable/Attainment.
Tipton County	.....	Unclassifiable/Attainment.
Trousdale County	.....	Unclassifiable/Attainment.
Unicoi County	.....	Unclassifiable/Attainment.
Union County	.....	Unclassifiable/Attainment.
Van Buren County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.
Weakley County	.....	Unclassifiable/Attainment.
White County	.....	Unclassifiable/Attainment.
Williamson County	.....	Unclassifiable/Attainment.
Wilson County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 45. In § 81.344, the table entitled ''Texas.—PM2.5'' is added to the end of the section to read as follows:

§ 81.344 Texas.

* * * * *

TEXAS.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
AQCR 022 Shreveport-Texarkana-Tyler Interstate:		
Anderson County	.....	Unclassifiable/Attainment.
Bowie County	.....	Unclassifiable/Attainment.
Camp County	.....	Unclassifiable/Attainment.
Cass County	.....	Unclassifiable/Attainment.
Cherokee County	.....	Unclassifiable/Attainment.

TEXAS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Delta County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Gregg County	.....	Unclassifiable/Attainment.
Harrison County	.....	Unclassifiable/Attainment.
Hopkins County	.....	Unclassifiable/Attainment.
Lamar County	.....	Unclassifiable/Attainment.
Marion County	.....	Unclassifiable/Attainment.
Morris County	.....	Unclassifiable/Attainment.
Panola County	.....	Unclassifiable/Attainment.
Rains County	.....	Unclassifiable/Attainment.
Red River County	.....	Unclassifiable/Attainment.
Rusk County	.....	Unclassifiable/Attainment.
Smith County	.....	Unclassifiable/Attainment.
Titus County	.....	Unclassifiable/Attainment.
Upshur County	.....	Unclassifiable/Attainment.
Van Zandt County	.....	Unclassifiable/Attainment.
Wood County	.....	Unclassifiable/Attainment.
AQCR 106 S Louisiana-SE Texas Interstate (remainder of):		
Angelina County	.....	Unclassifiable/Attainment.
Houston County	.....	Unclassifiable/Attainment.
Jasper County	.....	Unclassifiable/Attainment.
Nacogdoches County	.....	Unclassifiable/Attainment.
Newton County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Sabine County	.....	Unclassifiable/Attainment.
San Augustine County	.....	Unclassifiable/Attainment.
San Jacinto County	.....	Unclassifiable/Attainment.
Shelby County	.....	Unclassifiable/Attainment.
Trinity County	.....	Unclassifiable/Attainment.
Tyler County	.....	Unclassifiable/Attainment.
AQCR 153 El Paso-Las Cruces-Alamogordo Interstate:		
Brewster County	.....	Unclassifiable/Attainment.
Culberson County	.....	Unclassifiable/Attainment.
El Paso County	.....	Unclassifiable/Attainment.
Hudspeth County	.....	Unclassifiable/Attainment.
Jeff Davis County	.....	Unclassifiable/Attainment.
Presidio County	.....	Unclassifiable/Attainment.
AQCR 210 Abilene-Wichita Falls Intrastate:		
Archer County	.....	Unclassifiable/Attainment.
Baylor County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Callahan County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Coleman County	.....	Unclassifiable/Attainment.
Comanche County	.....	Unclassifiable/Attainment.
Cottle County	.....	Unclassifiable/Attainment.
Eastland County	.....	Unclassifiable/Attainment.
Fisher County	.....	Unclassifiable/Attainment.
Foard County	.....	Unclassifiable/Attainment.
Hardeman County	.....	Unclassifiable/Attainment.
Haskell County	.....	Unclassifiable/Attainment.
Jack County	.....	Unclassifiable/Attainment.
Jones County	.....	Unclassifiable/Attainment.
Kent County	.....	Unclassifiable/Attainment.
Knox County	.....	Unclassifiable/Attainment.
Mitchell County	.....	Unclassifiable/Attainment.
Montague County	.....	Unclassifiable/Attainment.
Nolan County	.....	Unclassifiable/Attainment.
Runnels County	.....	Unclassifiable/Attainment.
Scurry County	.....	Unclassifiable/Attainment.
Shackelford County	.....	Unclassifiable/Attainment.
Stephens County	.....	Unclassifiable/Attainment.
Stonewall County	.....	Unclassifiable/Attainment.
Taylor County	.....	Unclassifiable/Attainment.
Throckmorton County	.....	Unclassifiable/Attainment.
Wichita County	.....	Unclassifiable/Attainment.
Wilbarger County	.....	Unclassifiable/Attainment.
Young County	.....	Unclassifiable/Attainment.
AQCR 211 Amarillo-Lubbock Intrastate:		
Armstrong County	.....	Unclassifiable/Attainment.

TEXAS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Bailey County	.....	Unclassifiable/Attainment.
Briscoe County	.....	Unclassifiable/Attainment.
Carson County	.....	Unclassifiable/Attainment.
Castro County	.....	Unclassifiable/Attainment.
Childress County	.....	Unclassifiable/Attainment.
Cochran County	.....	Unclassifiable/Attainment.
Collingsworth County	.....	Unclassifiable/Attainment.
Crosby County	.....	Unclassifiable/Attainment.
Dallam County	.....	Unclassifiable/Attainment.
Deaf Smith County	.....	Unclassifiable/Attainment.
Dickens County	.....	Unclassifiable/Attainment.
Donley County	.....	Unclassifiable/Attainment.
Floyd County	.....	Unclassifiable/Attainment.
Garza County	.....	Unclassifiable/Attainment.
Gray County	.....	Unclassifiable/Attainment.
Hale County	.....	Unclassifiable/Attainment.
Hall County	.....	Unclassifiable/Attainment.
Hansford County	.....	Unclassifiable/Attainment.
Hartley County	.....	Unclassifiable/Attainment.
Hemphill County	.....	Unclassifiable/Attainment.
Hockley County	.....	Unclassifiable/Attainment.
Hutchinson County	.....	Unclassifiable/Attainment.
King County	.....	Unclassifiable/Attainment.
Lamb County	.....	Unclassifiable/Attainment.
Lipscomb County	.....	Unclassifiable/Attainment.
Lubbock County	.....	Unclassifiable/Attainment.
Lynn County	.....	Unclassifiable/Attainment.
Moore County	.....	Unclassifiable/Attainment.
Motley County	.....	Unclassifiable/Attainment.
Ochiltree County	.....	Unclassifiable/Attainment.
Oldham County	.....	Unclassifiable/Attainment.
Parmer County	.....	Unclassifiable/Attainment.
Potter County	.....	Unclassifiable/Attainment.
Randall County	.....	Unclassifiable/Attainment.
Roberts County	.....	Unclassifiable/Attainment.
Sherman County	.....	Unclassifiable/Attainment.
Swisher County	.....	Unclassifiable/Attainment.
Terry County	.....	Unclassifiable/Attainment.
Wheeler County	.....	Unclassifiable/Attainment.
Yoakum County	.....	Unclassifiable/Attainment.
AQCR 212 Austin-Waco Intrastate:		
Bastrop County	.....	Unclassifiable/Attainment.
Bell County	.....	Unclassifiable/Attainment.
Blanco County	.....	Unclassifiable/Attainment.
Bosque County	.....	Unclassifiable/Attainment.
Brazos County	.....	Unclassifiable/Attainment.
Burleson County	.....	Unclassifiable/Attainment.
Burnet County	.....	Unclassifiable/Attainment.
Caldwell County	.....	Unclassifiable/Attainment.
Coryell County	.....	Unclassifiable/Attainment.
Falls County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Freestone County	.....	Unclassifiable/Attainment.
Grimes County	.....	Unclassifiable/Attainment.
Hamilton County	.....	Unclassifiable/Attainment.
Hays County	.....	Unclassifiable/Attainment.
Hill County	.....	Unclassifiable/Attainment.
Lampasas County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.
Leon County	.....	Unclassifiable/Attainment.
Limestone County	.....	Unclassifiable/Attainment.
Llano County	.....	Unclassifiable/Attainment.
McLennan County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Milam County	.....	Unclassifiable/Attainment.
Mills County	.....	Unclassifiable/Attainment.
Robertson County	.....	Unclassifiable/Attainment.
San Saba County	.....	Unclassifiable/Attainment.
Travis County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.

TEXAS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Williamson County	.....	Unclassifiable/Attainment.
AQCR 213 Brownsville-Laredo Intrastate:		
Cameron County	.....	Unclassifiable/Attainment.
Hidalgo County	.....	Unclassifiable/Attainment.
Jim Hogg County	.....	Unclassifiable/Attainment.
Starr County	.....	Unclassifiable/Attainment.
Webb County	.....	Unclassifiable/Attainment.
Willacy County	.....	Unclassifiable/Attainment.
Zapata County	.....	Unclassifiable/Attainment.
AQCR 214 Corpus Christi-Victoria Intrastate (part):		
Nueces County	.....	Unclassifiable/Attainment.
AQCR 214 Corpus Christi-Victoria Intrastate (remainder of):		
Aransas County	.....	Unclassifiable/Attainment.
Bee County	.....	Unclassifiable/Attainment.
Brooks County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
DeWitt County	.....	Unclassifiable/Attainment.
Duval County	.....	Unclassifiable/Attainment.
Goliad County	.....	Unclassifiable/Attainment.
Gonzales County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jim Wells County	.....	Unclassifiable/Attainment.
Kenedy County	.....	Unclassifiable/Attainment.
Kleberg County	.....	Unclassifiable/Attainment.
Lavaca County	.....	Unclassifiable/Attainment.
Live Oak County	.....	Unclassifiable/Attainment.
McMullen County	.....	Unclassifiable/Attainment.
Refugio County	.....	Unclassifiable/Attainment.
San Patricio County	.....	Unclassifiable/Attainment.
AQCR 215 Metro Dallas-Fort Worth Intrastate (remainder of):		
Cooke County	.....	Unclassifiable/Attainment.
Erath County	.....	Unclassifiable/Attainment.
Fannin County	.....	Unclassifiable/Attainment.
Grayson County	.....	Unclassifiable/Attainment.
Henderson County	.....	Unclassifiable/Attainment.
Hood County	.....	Unclassifiable/Attainment.
Hunt County	.....	Unclassifiable/Attainment.
Navarro County	.....	Unclassifiable/Attainment.
Palo Pinto County	.....	Unclassifiable/Attainment.
Somervell County	.....	Unclassifiable/Attainment.
Wise County	.....	Unclassifiable/Attainment.
AQCR 216 Metro Houston-Galveston Intrastate (remainder of):		
Austin County	.....	Unclassifiable/Attainment.
Colorado County	.....	Unclassifiable/Attainment.
Matagorda County	.....	Unclassifiable/Attainment.
Walker County	.....	Unclassifiable/Attainment.
Wharton County	.....	Unclassifiable/Attainment.
AQCR 217 Metro San Antonio Intrastate (remainder of):		
Atascosa County	.....	Unclassifiable/Attainment.
Bandera County	.....	Unclassifiable/Attainment.
Dimmit County	.....	Unclassifiable/Attainment.
Edwards County	.....	Unclassifiable/Attainment.
Frio County	.....	Unclassifiable/Attainment.
Gillespie County	.....	Unclassifiable/Attainment.
Karnes County	.....	Unclassifiable/Attainment.
Kendall County	.....	Unclassifiable/Attainment.
Kerr County	.....	Unclassifiable/Attainment.
Kinney County	.....	Unclassifiable/Attainment.
La Salle County	.....	Unclassifiable/Attainment.
Maverick County	.....	Unclassifiable/Attainment.
Medina County	.....	Unclassifiable/Attainment.
Real County	.....	Unclassifiable/Attainment.
Uvalde County	.....	Unclassifiable/Attainment.
Val Verde County	.....	Unclassifiable/Attainment.
Wilson County	.....	Unclassifiable/Attainment.
Zavala County	.....	Unclassifiable/Attainment.
AQCR 218 Midland-Odessa-San Angelo Intrastate (part):		
Ector County	.....	Unclassifiable/Attainment.
AQCR 218 Midland-Odessa-San Angelo Intrastate (remainder of):		
Andrews County	.....	Unclassifiable/Attainment.

TEXAS.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Borden County	.....	Unclassifiable/Attainment.
Coke County	.....	Unclassifiable/Attainment.
Concho County	.....	Unclassifiable/Attainment.
Crane County	.....	Unclassifiable/Attainment.
Crockett County	.....	Unclassifiable/Attainment.
Dawson County	.....	Unclassifiable/Attainment.
Gaines County	.....	Unclassifiable/Attainment.
Glasscock County	.....	Unclassifiable/Attainment.
Howard County	.....	Unclassifiable/Attainment.
Irion County	.....	Unclassifiable/Attainment.
Kimble County	.....	Unclassifiable/Attainment.
Loving County	.....	Unclassifiable/Attainment.
McCulloch County	.....	Unclassifiable/Attainment.
Martin County	.....	Unclassifiable/Attainment.
Mason County	.....	Unclassifiable/Attainment.
Menard County	.....	Unclassifiable/Attainment.
Midland County	.....	Unclassifiable/Attainment.
Pecos County	.....	Unclassifiable/Attainment.
Reagan County	.....	Unclassifiable/Attainment.
Reeves County	.....	Unclassifiable/Attainment.
Schleicher County	.....	Unclassifiable/Attainment.
Sterling County	.....	Unclassifiable/Attainment.
Sutton County	.....	Unclassifiable/Attainment.
Terrell County	.....	Unclassifiable/Attainment.
Tom Green County	.....	Unclassifiable/Attainment.
Upton County	.....	Unclassifiable/Attainment.
Ward County	.....	Unclassifiable/Attainment.
Winkler County	.....	Unclassifiable/Attainment.
Beaumont/Port Arthur, TX:		
Hardin County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Orange County	.....	Unclassifiable/Attainment.
Dallas-Fort Worth, TX:		
Collin County	.....	Unclassifiable/Attainment.
Dallas County	.....	Unclassifiable/Attainment.
Denton County	.....	Unclassifiable/Attainment.
Ellis County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Kaufman County	.....	Unclassifiable/Attainment.
Parker County	.....	Unclassifiable/Attainment.
Rockwall County	.....	Unclassifiable/Attainment.
Tarrant County	.....	Unclassifiable/Attainment.
Houston-Galveston-Brazoria, TX:		
Brazoria County	.....	Unclassifiable/Attainment.
Chambers County	.....	Unclassifiable/Attainment.
Fort Bend County	.....	Unclassifiable/Attainment.
Galveston County	.....	Unclassifiable/Attainment.
Harris County	.....	Unclassifiable/Attainment.
Liberty County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Waller County	.....	Unclassifiable/Attainment.
San Antonio, TX:		
Bexar County	.....	Unclassifiable/Attainment.
Comal County	.....	Unclassifiable/Attainment.
Guadalupe County	.....	Unclassifiable/Attainment.
Victoria Area:		
Victoria County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 46. In § 81.345, the table entitled ''Utah.—PM2.5'' is added to the end of the section to read as follows:

§ 81.345 Utah.

* * * * *

UTAH.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Box Elder County, UT (part):		
Box Elder County (except Brigham City)	.....	Unclassifiable/Attainment.
Brigham City, UT:		
Box Elder County (part)	.....	Unclassifiable/Attainment.
The area surrounding Brigham City, as described by the following Townships or the portions of the following Townships in Box Elder County: T9N 2W, T9N R1W, T8N 2W		
Cache County, UT (part):		
Cache County (except Lower Cache Valley)	.....	Unclassifiable/Attainment.
Davis County, UT (part):		
Davis County (except Wasatch Front)	.....	Unclassifiable/Attainment.
Grantsville, UT:		
Tooele County (part)	.....	Unclassifiable/Attainment.
The area surrounding Grantsville, as described by the following Townships or the portions of the following Townships in Tooele County: T2S R6W, T2S R5W, T2S R4W, T3S R6W, T3S R5W, T3S R4W, T4S R6W, T4S R5W, T4S R4W		
Lower Cache Valley, UT:		
Cache County (part)	.....	Unclassifiable/Attainment.
The Cache Valley, below 6500 ft. msl. This area is described by the following list of Townships or the portions of the following Townships in Cache County: T15N R1E, T15N R2W, T15N R1W, T14N R2W, T14N R1W, T14N R1E, T13N R2W, T13N R1W, T13N R1E, T12N R2W, T12N R1W, T12N R1E, T11N R1W, T11N R1E, T10N R1W, T10N R1E, T9N R1E		
Salt Lake County, UT (part)		
Salt Lake County (except Wasatch Front)	.....	Unclassifiable/Attainment.
Tooele County, UT (part):		
Tooele County (remainder)	.....	Unclassifiable/Attainment.
Utah County, UT (part):		
Utah County (except Wasatch Front)	.....	Unclassifiable/Attainment.
Wasatch Front, UT:		
Davis County (part)	.....	Unclassifiable/Attainment.
The portion of the Wasatch Front residing in Davis County, as described by the following Townships or the portions of the following Townships in Davis County: T5N R3W, T5N R2W, T5N R1W, T4N R2W, T4N R1W, T3N R1W, T3N R1E, T2N R1W, T2N R1E, T1N R1W, T1N R1E.		
Salt Lake County (part)	.....	Unclassifiable/Attainment.
The portion of the Wasatch Front residing in Salt Lake County, as described by the following Townships or the portions of the following Townships in Salt Lake County: T1N R2W, T1N R1W, T1N R1E, T1S R3W, T1S R2W, T1S R1W, T1S R1E, T2S R3W, T2S R2W, T2S R1W, T2S R1E, T3S R3W, T3S R2W, T3S R1W, T3S R1E, T4S R3W, T4S R2W, T4S R1W, T4S R1E.		
Utah County (part)	.....	Unclassifiable/Attainment.
The portion of the Wasatch Front residing in Utah County, as described by the following Townships or the portions of the following Townships in Utah County: T4S R2W, T4S R1W, T4S R1E, T4S R2E, T5S R2W, T5S R1W, T5S R1E, T5S R2E, T6S R3W, T6S R2W, T6S R1W, T6S R2E, T6S R3E, T6S R1E, T7S R3W, T7S R2W, T7S R1W, T7S R1E, T7S R2E, T7S R3E, T8S R3W, T8S R2W, T8S R1W, T8S R3E, T8S R2E, T8S R1E, T9S R3W, T9S R2W, T9S R1E, T9S R3E, T9S R2E, T9S R1W, T10S 2W, T10S R2E, T10S R1E, T10S R1W, T1S R2W, T11S R1W, T12S R2W.		
Weber County (part)	.....	Unclassifiable/Attainment.
The portion of the Wasatch Front residing in Weber County, as described by the following Townships or the portions of the following Townships in Weber County: T7N R2W, T7N R1W, T7N R3W, T6N R3W, T6N R2W, T6N R1W, T5N R3W, T5N R2W, T5N R1W		
Weber County, UT (part):		
Weber County (except Wasatch Front)	.....	Unclassifiable/Attainment.
Rest of State:		
Beaver County	.....	Unclassifiable/Attainment.
Carbon County	.....	Unclassifiable/Attainment.
Daggett County	.....	Unclassifiable/Attainment.
Duchesne County	.....	Unclassifiable/Attainment.
Emery County	.....	Unclassifiable/Attainment.
Garfield County	.....	Unclassifiable/Attainment.
Grand County	.....	Unclassifiable/Attainment.
Iron County	.....	Unclassifiable/Attainment.
Juab County	.....	Unclassifiable/Attainment.
Kane County	.....	Unclassifiable/Attainment.
Millard County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Piute County	.....	Unclassifiable/Attainment.
Rich County	.....	Unclassifiable/Attainment.

UTAH.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
San Juan County	.....	Unclassifiable/Attainment.
Sanpete County	.....	Unclassifiable/Attainment.
Sevier County	.....	Unclassifiable/Attainment.
Summit County	.....	Unclassifiable/Attainment.
Uintah County	.....	Unclassifiable/Attainment.
Wasatch County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wayne County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 47. In § 81.346, the table entitled ''Vermont.—PM2.5'' is added to the end of the section to read as follows:

§ 81.346 Vermont.

* * * * *

VERMONT.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Addison County	.....	Unclassifiable/Attainment.
Bennington County	.....	Unclassifiable/Attainment.
Caledonia County	.....	Unclassifiable/Attainment.
Chittenden County	.....	Unclassifiable/Attainment.
Essex County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Grand Isle County	.....	Unclassifiable/Attainment.
Lamoille County	.....	Unclassifiable/Attainment.
Orange County	.....	Unclassifiable/Attainment.
Orleans County	.....	Unclassifiable/Attainment.
Rutland County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Windham County	.....	Unclassifiable/Attainment.
Windsor County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 48. In § 81.347, the table entitled ''Virginia.—PM2.5'' is added to the end of the section to read as follows:

§ 81.347 Virginia.

* * * * *

VIRGINIA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Washington, DC-MD-VA:		
Arlington County	.....	Nonattainment.
Fairfax County	.....	Nonattainment.
Loudoun County	.....	Nonattainment.
Prince William County	.....	Nonattainment.
Alexandria City	.....	Nonattainment.
Fairfax City	.....	Nonattainment.
Falls Church City	.....	Nonattainment.
Manassas City	.....	Nonattainment.
Manassas Park City	.....	Nonattainment.
AQCR 207 Eastern Tennessee-SW Virginia Interstate (remainder of):		
Bland County	.....	Unclassifiable/Attainment.
Buchanan County	.....	Unclassifiable/Attainment.
Carroll County	.....	Unclassifiable/Attainment.
Dickenson County	.....	Unclassifiable/Attainment.
Grayson County	.....	Unclassifiable/Attainment.
Lee County	.....	Unclassifiable/Attainment.

VIRGINIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Russell County	.....	Unclassifiable/Attainment.
Scott County	.....	Unclassifiable/Attainment.
Smyth County	.....	Unclassifiable/Attainment.
Tazewell County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Wise County	.....	Unclassifiable/Attainment.
Wythe County	.....	Unclassifiable/Attainment.
Bristol City	.....	Unclassifiable/Attainment.
Galax City	.....	Unclassifiable/Attainment.
Norton City	.....	Unclassifiable/Attainment.
AQCR 222 Central Virginia Intrastate:		
Amelia County	.....	Unclassifiable/Attainment.
Amherst County	.....	Unclassifiable/Attainment.
Appomattox County	.....	Unclassifiable/Attainment.
Bedford County	.....	Unclassifiable/Attainment.
Brunswick County	.....	Unclassifiable/Attainment.
Buckingham County	.....	Unclassifiable/Attainment.
Campbell County	.....	Unclassifiable/Attainment.
Charlotte County	.....	Unclassifiable/Attainment.
Cumberland County	.....	Unclassifiable/Attainment.
Franklin County	.....	Unclassifiable/Attainment.
Halifax County	.....	Unclassifiable/Attainment.
Henry County	.....	Unclassifiable/Attainment.
Lunenburg County	.....	Unclassifiable/Attainment.
Mecklenburg County	.....	Unclassifiable/Attainment.
Nottoway County	.....	Unclassifiable/Attainment.
Patrick County	.....	Unclassifiable/Attainment.
Pittsylvania County	.....	Unclassifiable/Attainment.
Prince Edward County	.....	Unclassifiable/Attainment.
Bedford City	.....	Unclassifiable/Attainment.
Danville City	.....	Unclassifiable/Attainment.
Lynchburg City	.....	Unclassifiable/Attainment.
Martinsville City	.....	Unclassifiable/Attainment.
AQCR 223 Hampton Roads Intrastate (remainder of):		
Southampton County	.....	Unclassifiable/Attainment.
Franklin City	.....	Unclassifiable/Attainment.
AQCR 224 NE Virginia Intrastate (remainder of):		
Accomack County	.....	Unclassifiable/Attainment.
Albemarle County	.....	Unclassifiable/Attainment.
Caroline County	.....	Unclassifiable/Attainment.
Culpeper County	.....	Unclassifiable/Attainment.
Essex County	.....	Unclassifiable/Attainment.
Fauquier County	.....	Unclassifiable/Attainment.
Fluvanna County	.....	Unclassifiable/Attainment.
Greene County	.....	Unclassifiable/Attainment.
King and Queen County	.....	Unclassifiable/Attainment.
King George County	.....	Unclassifiable/Attainment.
King William County	.....	Unclassifiable/Attainment.
Lancaster County	.....	Unclassifiable/Attainment.
Louisa County	.....	Unclassifiable/Attainment.
Madison County	.....	Unclassifiable/Attainment.
Mathews County	.....	Unclassifiable/Attainment.
Middlesex County	.....	Unclassifiable/Attainment.
Nelson County	.....	Unclassifiable/Attainment.
Northampton County	.....	Unclassifiable/Attainment.
Northumberland County	.....	Unclassifiable/Attainment.
Orange County	.....	Unclassifiable/Attainment.
Rappahannock County	.....	Unclassifiable/Attainment.
Richmond County	.....	Unclassifiable/Attainment.
Westmoreland County	.....	Unclassifiable/Attainment.
Charlottesville City	.....	Unclassifiable/Attainment.
AQCR 225 State Capital Intrastate (remainder of):		
Dinwiddie County	.....	Unclassifiable/Attainment.
Goochland County	.....	Unclassifiable/Attainment.
Greensville County	.....	Unclassifiable/Attainment.
New Kent County	.....	Unclassifiable/Attainment.
Powhatan County	.....	Unclassifiable/Attainment.
Surry County	.....	Unclassifiable/Attainment.
Sussex County	.....	Unclassifiable/Attainment.
Emporia City	.....	Unclassifiable/Attainment.

VIRGINIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Petersburg City	.....	Unclassifiable/Attainment.
AQCR 226 Valley of Virginia Intrastate:		
Alleghany County	.....	Unclassifiable/Attainment.
Augusta County	.....	Unclassifiable/Attainment.
Bath County	.....	Unclassifiable/Attainment.
Clarke County	.....	Unclassifiable/Attainment.
Craig County	.....	Unclassifiable/Attainment.
Floyd County	.....	Unclassifiable/Attainment.
Giles County	.....	Unclassifiable/Attainment.
Highland County	.....	Unclassifiable/Attainment.
Montgomery County	.....	Unclassifiable/Attainment.
Page County	.....	Unclassifiable/Attainment.
Pulaski County	.....	Unclassifiable/Attainment.
Rockbridge County	.....	Unclassifiable/Attainment.
Rockingham County	.....	Unclassifiable/Attainment.
Shenandoah County	.....	Unclassifiable/Attainment.
Warren County	.....	Unclassifiable/Attainment.
Buena Vista City	.....	Unclassifiable/Attainment.
Covington City	.....	Unclassifiable/Attainment.
Harrisonburg City	.....	Unclassifiable/Attainment.
Lexington City	.....	Unclassifiable/Attainment.
Radford City	.....	Unclassifiable/Attainment.
Staunton City	.....	Unclassifiable/Attainment.
Waynesboro City	.....	Unclassifiable/Attainment.
Frederick Co., VA:		
Frederick County	.....	Unclassifiable/Attainment.
Winchester City	.....	Unclassifiable/Attainment.
Fredericksburg, VA:		
Spotsylvania County	.....	Unclassifiable/Attainment.
Stafford County	.....	Unclassifiable/Attainment.
City of Fredericksburg	.....	Unclassifiable/Attainment.
Norfolk-Virginia-Beach Newport News (Hampton Roads), VA:		
Gloucester County	.....	Unclassifiable/Attainment.
Isle of Wight County	.....	Unclassifiable/Attainment.
James City County	.....	Unclassifiable/Attainment.
York County	.....	Unclassifiable/Attainment.
Chesapeake City	.....	Unclassifiable/Attainment.
Hampton City	.....	Unclassifiable/Attainment.
Newport News City	.....	Unclassifiable/Attainment.
Norfolk City	.....	Unclassifiable/Attainment.
Poquoson City	.....	Unclassifiable/Attainment.
Portsmouth City	.....	Unclassifiable/Attainment.
Suffolk City	.....	Unclassifiable/Attainment.
Virginia Beach City	.....	Unclassifiable/Attainment.
Williamsburg City	.....	Unclassifiable/Attainment.
Richmond-Petersburg, VA:		
Charles City County	.....	Unclassifiable/Attainment.
Chesterfield County	.....	Unclassifiable/Attainment.
Hanover County	.....	Unclassifiable/Attainment.
Henrico County	.....	Unclassifiable/Attainment.
Prince George County	.....	Unclassifiable/Attainment.
Colonial Heights City	.....	Unclassifiable/Attainment.
Hopewell City	.....	Unclassifiable/Attainment.
Richmond City	.....	Unclassifiable/Attainment.
Roanoke, VA:		
Botetourt County	.....	Unclassifiable/Attainment.
Roanoke County	.....	Unclassifiable/Attainment.
Roanoke City	.....	Unclassifiable/Attainment.
Salem City	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 49. In § 81.348, the table entitled ''Washington.—PM2.5'' is added to the end of the section to read as follows:

§ 81.348 Washington.

* * * * *

WASHINGTON.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Portland—Vancouver AQMA:		
Clark County (part)	.....	Unclassifiable/Attainment.
Air quality maintenance area		
Seattle—Tacoma Area	.....	Unclassifiable/Attainment.
The following boundary includes all of Pierce County, and all of King County except a small portion on the north-east corner and the western portion of Snohomish County: Starting at the mouth of the Nisqually river extend northwesterly along the Pierce County line to the southernmost point of the west county line of King County; thence northerly along the county line to the southernmost point of the west county line of Snohomish County; thence northerly along the county line to the intersection with SR 532; thence easterly along the north line of SR 532 to the intersection of I–5, continuing east along the same road now identified as Henning Rd., to the intersection with SR 9 at Bryant; thence continuing easterly on Bryant East Rd. and Rock Creek Rd., also identified as Grandview Rd., approximately 3 miles to the point at which it is crossed by the existing BPA electrical transmission line; thence southeasterly along the BPA transmission line approximately 8 miles to point of the crossing of the south fork of the Stillaguamish River; thence continuing in a southeasterly direction in a meander line following the bed of the River to Jordan Road; southerly along Jordan Road to the north city limits of Granite Falls; thence following the north and east city limits to 92nd St. N.E. and Menzel Lake Rd.; thence south-southeasterly along the Menzel Lake Rd. and the Lake Roesiger Rd. a distance of approximately 6 miles to the northernmost point of Lake Roesiger; thence southerly along a meander line following the middle of the Lake and Roesiger Creek to Woods Creek; thence southerly along a meander line following the bed of the Creek approximately 6 miles to the point the Creek is crossed by the existing BPA electrical transmission line; thence easterly along the BPA transmission line approximately 0.2 miles; thence southerly along the BPA Chief Joseph-Covington electrical transmission line approximately 3 miles to the north line of SR 2; thence southeasterly along SR 2 to the intersection with the east county line of King County; thence south along the county line to the northernmost point of the east county line of Pierce County; thence along the county line to the point of beginning at the mouth of the Nisqually River.		
AQCR 062 E Washington-N Idaho Interstate (part):		
Spokane County	.....	Unclassifiable/Attainment.
AQCR 062 E Washington-N Idaho Interstate (remainder of):		
Adams County	.....	Unclassifiable/Attainment.
Asotin County	.....	Unclassifiable/Attainment.
Columbia County	.....	Unclassifiable/Attainment.
Garfield County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Whitman County	.....	Unclassifiable/Attainment.
AQCR 193 Portland Interstate (remainder of):		
Clark County (remainder)	.....	Unclassifiable/Attainment.
Cowlitz County	.....	Unclassifiable/Attainment.
Lewis County	.....	Unclassifiable/Attainment.
Skamania County	.....	Unclassifiable/Attainment.
Wahkiakum County	.....	Unclassifiable/Attainment.
AQCR 227 Northern Washington Intrastate:		
Chelan County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Ferry County	.....	Unclassifiable/Attainment.
Okanogan County	.....	Unclassifiable/Attainment.
Pend Oreille County	.....	Unclassifiable/Attainment.
Stevens County	.....	Unclassifiable/Attainment.
AQCR 228 Olympic-Northwest Washington Intrastate:		
Clallam County	.....	Unclassifiable/Attainment.
Grays Harbor County	.....	Unclassifiable/Attainment.
Island County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Mason County	.....	Unclassifiable/Attainment.
Pacific County	.....	Unclassifiable/Attainment.
San Juan County	.....	Unclassifiable/Attainment.
Skagit County	.....	Unclassifiable/Attainment.
Thurston County	.....	Unclassifiable/Attainment.
Whatcom County	.....	Unclassifiable/Attainment.
AQCR 229 Puget Sound Intrastate (remainder of):		
King County (remainder)	.....	Unclassifiable/Attainment.
Kitsap County	.....	Unclassifiable/Attainment.
Snohomish County (remainder)	.....	Unclassifiable/Attainment.
AQCR 230 South Central Washington Intrastate:		
Benton County	.....	Unclassifiable/Attainment.

WASHINGTON.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Franklin County	.....	Unclassifiable/Attainment.
Kittitas County	.....	Unclassifiable/Attainment.
Klickitat County	.....	Unclassifiable/Attainment.
Walla Walla County	.....	Unclassifiable/Attainment.
Yakima County	.....	Unclassifiable/Attainment.
Seattle-Tacoma Area:		
Pierce County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 50. In § 81.349, the table entitled ''West Virginia.—PM2.5'' is added to the end of the section to read as follows:

§ 81.349 West Virginia.

* * * * *

WEST VIRGINIA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Charleston, WV:		
Kanawha County	.....	Nonattainment.
Putnam County	.....	Nonattainment.
Huntington-Ashland, WV-KY-OH:		
Cabell County	.....	Nonattainment.
Mason County (part)	.....	Nonattainment.
Graham Tax District		
Wayne County	.....	Nonattainment.
Marion County, WV (aka Fairmont CBSA):		
Harrison County (part)	.....	Nonattainment.
Tax District of Clay		
Marion County	.....	Nonattainment.
Monongalia County (part)	.....	Nonattainment.
Tax District of Cass		
Martinsburg, WV-Hagerstown, MD:		
Berkeley County	.....	Nonattainment.
Parkersburg-Marietta, WV-OH:		
Pleasants County (part)	.....	Nonattainment.
Tax District of Grant		
Wood County	.....	Nonattainment.
Steubenville-Weirton, OH-WV:		
Brooke County	.....	Nonattainment.
Hancock County	.....	Nonattainment.
Wheeling, WV-OH:		
Marshall County	.....	Nonattainment.
Ohio County	.....	Nonattainment.
Rest of State:		
Barbour County	.....	Unclassifiable/Attainment.
Boone County	.....	Unclassifiable/Attainment.
Braxton County	.....	Unclassifiable/Attainment.
Calhoun County	.....	Unclassifiable/Attainment.
Clay County	.....	Unclassifiable/Attainment.
Doddridge County	.....	Unclassifiable/Attainment.
Fayette County	.....	Unclassifiable/Attainment.
Gilmer County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Greenbrier County	.....	Unclassifiable/Attainment.
Hampshire County	.....	Unclassifiable/Attainment.
Hardy County	.....	Unclassifiable/Attainment.
Harrison County (remainder)	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Lewis County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Logan County	.....	Unclassifiable/Attainment.
McDowell County	.....	Unclassifiable/Attainment.
Mason County (remainder)	.....	Unclassifiable/Attainment.
Mercer County	.....	Unclassifiable/Attainment.
Mineral County	.....	Unclassifiable/Attainment.

WEST VIRGINIA.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Mingo County	.....	Unclassifiable/Attainment.
Monongalia County (remainder)	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Morgan County	.....	Unclassifiable/Attainment.
Nicholas County	.....	Unclassifiable/Attainment.
Pendleton County	.....	Unclassifiable/Attainment.
Pleasants County (remainder)	.....	Unclassifiable/Attainment.
Pocahontas County	.....	Unclassifiable/Attainment.
Preston County	.....	Unclassifiable/Attainment.
Raleigh County	.....	Unclassifiable/Attainment.
Randolph County	.....	Unclassifiable/Attainment.
Ritchie County	.....	Unclassifiable/Attainment.
Roane County	.....	Unclassifiable/Attainment.
Summers County	.....	Unclassifiable/Attainment.
Taylor County	.....	Unclassifiable/Attainment.
Tucker County	.....	Unclassifiable/Attainment.
Tyler County	.....	Unclassifiable/Attainment.
Upshur County	.....	Unclassifiable/Attainment.
Webster County	.....	Unclassifiable/Attainment.
Wetzel County	.....	Unclassifiable/Attainment.
Wirt County	.....	Unclassifiable/Attainment.
Wyoming County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 51. In § 81.350, the table entitled ''Wisconsin.—PM2.5'' is added to the end of the section to read as follows:

§ 81.350 Wisconsin.

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WISCONSIN.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Adams County	.....	Unclassifiable/Attainment.
Ashland County	.....	Unclassifiable/Attainment.
Barron County	.....	Unclassifiable/Attainment.
Bayfield County	.....	Unclassifiable/Attainment.
Brown County	.....	Unclassifiable/Attainment.
Buffalo County	.....	Unclassifiable/Attainment.
Burnett County	.....	Unclassifiable/Attainment.
Calumet County	.....	Unclassifiable/Attainment.
Chippewa County	.....	Unclassifiable/Attainment.
Clark County	.....	Unclassifiable/Attainment.
Columbia County	.....	Unclassifiable/Attainment.
Crawford County	.....	Unclassifiable/Attainment.
Dane County	.....	Unclassifiable/Attainment.
Dodge County	.....	Unclassifiable/Attainment.
Door County	.....	Unclassifiable/Attainment.
Douglas County	.....	Unclassifiable/Attainment.
Dunn County	.....	Unclassifiable/Attainment.
Eau Claire County	.....	Unclassifiable/Attainment.
Florence County	.....	Unclassifiable/Attainment.
Fond du Lac County	.....	Unclassifiable/Attainment.
Forest County	.....	Unclassifiable/Attainment.
Grant County	.....	Unclassifiable/Attainment.
Green County	.....	Unclassifiable/Attainment.
Green Lake County	.....	Unclassifiable/Attainment.
Iowa County	.....	Unclassifiable/Attainment.
Iron County	.....	Unclassifiable/Attainment.
Jackson County	.....	Unclassifiable/Attainment.
Jefferson County	.....	Unclassifiable/Attainment.
Juneau County	.....	Unclassifiable/Attainment.
Kenosha County	.....	Unclassifiable/Attainment.
Kewaunee County	.....	Unclassifiable/Attainment.
La Crosse County	.....	Unclassifiable/Attainment.

WISCONSIN.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Lafayette County	.....	Unclassifiable/Attainment.
Langlade County	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Manitowoc County	.....	Unclassifiable/Attainment.
Marathon County	.....	Unclassifiable/Attainment.
Marinette County	.....	Unclassifiable/Attainment.
Marquette County	.....	Unclassifiable/Attainment.
Menominee County	.....	Unclassifiable/Attainment.
Milwaukee County	.....	Unclassifiable/Attainment.
Monroe County	.....	Unclassifiable/Attainment.
Oconto County	.....	Unclassifiable/Attainment.
Oneida County	.....	Unclassifiable/Attainment.
Outagamie County	.....	Unclassifiable/Attainment.
Ozaukee County	.....	Unclassifiable/Attainment.
Pepin County	.....	Unclassifiable/Attainment.
Pierce County	.....	Unclassifiable/Attainment.
Polk County	.....	Unclassifiable/Attainment.
Portage County	.....	Unclassifiable/Attainment.
Price County	.....	Unclassifiable/Attainment.
Racine County	.....	Unclassifiable/Attainment.
Richland County	.....	Unclassifiable/Attainment.
Rock County	.....	Unclassifiable/Attainment.
Rusk County	.....	Unclassifiable/Attainment.
St. Croix County	.....	Unclassifiable/Attainment.
Sauk County	.....	Unclassifiable/Attainment.
Sawyer County	.....	Unclassifiable/Attainment.
Shawano County	.....	Unclassifiable/Attainment.
Sheboygan County	.....	Unclassifiable/Attainment.
Taylor County	.....	Unclassifiable/Attainment.
Trempealeau County	.....	Unclassifiable/Attainment.
Vernon County	.....	Unclassifiable/Attainment.
Vilas County	.....	Unclassifiable/Attainment.
Walworth County	.....	Unclassifiable/Attainment.
Washburn County	.....	Unclassifiable/Attainment.
Washington County	.....	Unclassifiable/Attainment.
Waukesha County	.....	Unclassifiable/Attainment.
Waupaca County	.....	Unclassifiable/Attainment.
Waushara County	.....	Unclassifiable/Attainment.
Winnebago County	.....	Unclassifiable/Attainment.
Wood County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 52. In § 81.351, the table entitled ''Wyoming.—PM2.5'' is added to the end of the section to read as follows:

§ 81.351 Wyoming.

* * * * *

WYOMING.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Casper, WY:		
Natrona County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Casper		
Cheyenne, WY:		
Laramie County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Cheyenne		
Evanston, WY:		
Uinta County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Evanston		
Gillette, WY:		
Campbell County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Gillette		
Jackson, WY:		
Teton County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Jackson		

WYOMING.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Lander, WY:		
Fremont County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Lander		
Laramie, WY:		
Albany County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Laramie		
Riverton, WY:		
Fremont County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Riverton		
Rock Springs, WY:		
Sweetwater County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Rock Springs		
Sheridan, WY:		
Sheridan County (part)	.....	Unclassifiable/Attainment.
The portion within the City of Sheridan		
Rest of State:		
Albany County (remainder)	.....	Unclassifiable/Attainment.
Big Horn County	.....	Unclassifiable/Attainment.
Campbell County	.....	Unclassifiable/Attainment.
Carbon County	.....	Unclassifiable/Attainment.
Converse County	.....	Unclassifiable/Attainment.
Crook County	.....	Unclassifiable/Attainment.
Fremont County (remainder)	.....	Unclassifiable/Attainment.
Goshen County	.....	Unclassifiable/Attainment.
Hot Springs County	.....	Unclassifiable/Attainment.
Johnson County	.....	Unclassifiable/Attainment.
Laramie County (remainder)	.....	Unclassifiable/Attainment.
Lincoln County	.....	Unclassifiable/Attainment.
Natrona County (remainder)	.....	Unclassifiable/Attainment.
Niobrara County	.....	Unclassifiable/Attainment.
Park County	.....	Unclassifiable/Attainment.
Platte County	.....	Unclassifiable/Attainment.
Sheridan County (remainder)	.....	Unclassifiable/Attainment.
Sublette County	.....	Unclassifiable/Attainment.
Sweetwater County	.....	Unclassifiable/Attainment.
Teton County (remainder)	.....	Unclassifiable/Attainment.
Uinta County (remainder)	.....	Unclassifiable/Attainment.
Washakie County	.....	Unclassifiable/Attainment.
Weston County	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ In § 81.352, the table entitled ''American Samoa.—PM2.5'' is added to the end of the section to read as follows:

§ 81.352 American Samoa.

* * * * *

AMERICAN SAMOA.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Eastern District	.....	Unclassifiable/Attainment.
Manu'a District	.....	Unclassifiable/Attainment.
Rose Island	.....	Unclassifiable/Attainment.
Swains Island	.....	Unclassifiable/Attainment.
Western District	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 54. In § 81.353, the table entitled ''Guam.—PM2.5'' is added to the end of the section to read as follows:

§ 81.353 Guam.

* * * * *

GUAM.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Guam	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 55. In § 81.354, the table entitled ''Northern Mariana Islands.—PM2.5'' is added to the end of the section to read as follows:

§ 81.354 Northern Mariana Islands.

* * * * *

NORTHERN MARIANA ISLANDS.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Northern Islands Municipality	.....	Unclassifiable/Attainment.
Rota Municipality	.....	Unclassifiable/Attainment.
Saipan Municipality	.....	Unclassifiable/Attainment.
Tinian Municipality	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 56. In § 81.355, the table entitled ''Puerto Rico.—PM2.5'' is added to the end of the section to read as follows:

§ 81.355 Puerto Rico.

* * * * *

PUERTO RICO.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
Adjuntas Municipio	.....	Unclassifiable/Attainment.
Aguada Municipio	.....	Unclassifiable/Attainment.
Aguadilla Municipio	.....	Unclassifiable/Attainment.
Aguas Buenas Municipio	.....	Unclassifiable/Attainment.
Aibonito Municipio	.....	Unclassifiable/Attainment.
Añasco Municipio	.....	Unclassifiable/Attainment.
Arecibo Municipio	.....	Unclassifiable/Attainment.
Arroyo Municipio	.....	Unclassifiable/Attainment.
Barceloneta Municipio	.....	Unclassifiable/Attainment.
Barranquit´as Municipio	.....	Unclassifiable/Attainment.
Bayamón County	.....	Unclassifiable/Attainment.
Cabo Rojo Municipio	.....	Unclassifiable/Attainment.
Caguas Municipio	.....	Unclassifiable/Attainment.
Camuy Municipio	.....	Unclassifiable/Attainment.
Canóvanas Municipio	.....	Unclassifiable/Attainment.
Carolina Municipio	.....	Unclassifiable/Attainment.
Cataño County	.....	Unclassifiable/Attainment.
Cayey Municipio	.....	Unclassifiable/Attainment.
Ceiba Municipio	.....	Unclassifiable/Attainment.
Ciales Municipio	.....	Unclassifiable/Attainment.
Cidra Municipio	.....	Unclassifiable/Attainment.
Coamo Municipio	.....	Unclassifiable/Attainment.
Comerío Municipio	.....	Unclassifiable/Attainment.
Corozal Municipio	.....	Unclassifiable/Attainment.
Culebra Municipio	.....	Unclassifiable/Attainment.
Dorado Municipio	.....	Unclassifiable/Attainment.
Fajardo Municipio	.....	Unclassifiable/Attainment.
Florida Municipio	.....	Unclassifiable/Attainment.
Guánica Municipio	.....	Unclassifiable/Attainment.
Guayama Municipio	.....	Unclassifiable/Attainment.
Guayanilla Municipio	.....	Unclassifiable/Attainment.
Guaynabo County	.....	Unclassifiable/Attainment.
Gurabo Municipio	.....	Unclassifiable/Attainment.
Hatillo Municipio	.....	Unclassifiable/Attainment.

PUERTO RICO.—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Hormigueros Municipio	.....	Unclassifiable/Attainment.
Humacao Municipio	.....	Unclassifiable/Attainment.
Isabela Municipio	.....	Unclassifiable/Attainment.
Jayuya Municipio	.....	Unclassifiable/Attainment.
Juana Díaz Municipio	.....	Unclassifiable/Attainment.
Juncos Municipio	.....	Unclassifiable/Attainment.
Lajas Municipio	.....	Unclassifiable/Attainment.
Lares Municipio	.....	Unclassifiable/Attainment.
Las Marías Municipio	.....	Unclassifiable/Attainment.
Las Piedras Municipio	.....	Unclassifiable/Attainment.
Loíza Municipio	.....	Unclassifiable/Attainment.
Luquillo Municipio	.....	Unclassifiable/Attainment.
Manatí Municipio	.....	Unclassifiable/Attainment.
Maricao Municipio	.....	Unclassifiable/Attainment.
Maunabo Municipio	.....	Unclassifiable/Attainment.
Mayagnez Municipio	.....	Unclassifiable/Attainment.
Moca Municipio	.....	Unclassifiable/Attainment.
Morovis Municipio	.....	Unclassifiable/Attainment.
Naguabo Municipio	.....	Unclassifiable/Attainment.
Naranjito Municipio	.....	Unclassifiable/Attainment.
Orocovis Municipio	.....	Unclassifiable/Attainment.
Patillas Municipio	.....	Unclassifiable/Attainment.
Peñuelas Municipio	.....	Unclassifiable/Attainment.
Ponce Municipio	.....	Unclassifiable/Attainment.
Quebradillas Municipio	.....	Unclassifiable/Attainment.
Rincón Municipio	.....	Unclassifiable/Attainment.
Río Grande Municipio	.....	Unclassifiable/Attainment.
Sabana Grande Municipio	.....	Unclassifiable/Attainment.
Salinas Municipio	.....	Unclassifiable/Attainment.
San Germán Municipio	.....	Unclassifiable/Attainment.
San Juan Municipio	.....	Unclassifiable/Attainment.
San Lorenzo Municipio	.....	Unclassifiable/Attainment.
San Sebastián Municipio	.....	Unclassifiable/Attainment.
Santa Isabel Municipio	.....	Unclassifiable/Attainment.
Toa Alta Municipio	.....	Unclassifiable/Attainment.
Toa Baja County	.....	Unclassifiable/Attainment.
Trujillo Alto Municipio	.....	Unclassifiable/Attainment.
Utuado Municipio	.....	Unclassifiable/Attainment.
Vega Alta Municipio	.....	Unclassifiable/Attainment.
Vega Baja Municipio	.....	Unclassifiable/Attainment.
Vieques Municipio	.....	Unclassifiable/Attainment.
Villalba Municipio	.....	Unclassifiable/Attainment.
Yabucoa Municipio	.....	Unclassifiable/Attainment.
Yauco Municipio	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 57. In § 81.356, the table entitled ''Virgin Islands.—PM2.5'' is added to the end of the section to read as follows:

§ 81.356 Virgin Islands.

* * * * *

VIRGIN ISLANDS.—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Statewide:		
St. Croix	.....	Unclassifiable/Attainment.
St. John	.....	Unclassifiable/Attainment.
St. Thomas	.....	Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

[FR Doc. 05–1 Filed 1–4–05; 8:45 am]
BILLING CODE 6560–50–P

Air and Radiation (OAR) is now nearing completion of the analytical work for the second prospective study. The AQMS met on February 19, 2010 [**Federal Register** Notice dated January 26, 2010 (75 FR 4070–4071)] to review technical documents pertaining to modeling of air quality for seven emissions scenarios: a 1990 baseline simulation; and simulations for 2000, 2010 and 2020 with and without the CAAA. Materials for the February 19 meeting are available on the Council Web site at *http://yosemite.epa.gov/sab/SABPRODUCT.NSF/MeetingCal/962D3C3D233888B085257695005098B5?OpenDocument.* The purpose of the March 15 teleconference meeting is to discuss and finalize the AQMS draft advisory report.

Technical Contacts: The Office of Air and Radiation technical contact for the Second Section 812 Benefit-Cost Analysis of the Clean Air Act is Mr. Jim DeMocker at (202) 564–1673 or *democker.jim@epa.gov*.

Availability of Meeting Materials: The AQMS draft advisory report and meeting agenda for the March 2010 teleconference will be posted to the Council Web site (*http://www.epa.gov/advisorycouncilcaa*) prior to the meeting. EPA draft documents provided to the AQMS are available at *http://www.epa.gov/oar/sect812/prospective2.html.*

Procedures for Providing Public Input: Interested members of the public may submit relevant written or oral information for the AQMS to consider on the topics of this advisory activity. *Oral Statements:* In general, individuals or groups requesting an oral presentation at a teleconference meeting will be limited to three minutes per speaker, with no more than a total of one hour for all speakers. Interested parties should contact Ms. Sanzone at the contact information provided above by March 10, 2010, to be placed on the public speaker list for the March 15, 2010 meeting. *Written Statements:* Written statements should be received in the SAB Staff Office by March 10, 2010, so that the information can be made available to the AQMS for their consideration prior to the meeting. Written statements should be supplied to Ms. Sanzone in the following formats: one hard copy with original signature and one electronic copy via e-mail (acceptable file format: Adobe Acrobat PDF, MS Word, WordPerfect, MS PowerPoint, or Rich Text files). Submitters are asked to provide electronic versions of each document submitted with *and* without signatures, because the SAB Staff Office does not publish documents with signatures on its Web sites.

Accessibility: For information on access or services for individuals with disabilities, please contact Ms. Sanzone at (202) 343–9697, or via e-mail at *sanzone.stephanie@epa.gov,* preferably at least ten (10) days prior to the meeting, to give EPA as much time as possible to process your request.

Dated: February 24, 2010.

Anthony Maciorowski,

Deputy Director, EPA Science Advisory Board Staff Office.

[FR Doc. 2010–4311 Filed 3–1–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9121–1]

Official Release of the MOVES2010 Motor Vehicle Emissions Model for Emissions Inventories in SIPs and Transportation Conformity

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability.

SUMMARY: EPA is approving and announcing the availability of the Motor Vehicle Emissions Simulator model (MOVES2010) for official use outside of California. MOVES2010 is the state-of-the-art upgrade to EPA's modeling tools for estimating emissions from cars, trucks, motorcycles, and buses, based on analysis of millions of emission test results and considerable advances in the Agency's understanding of vehicle emissions.

Today's notice approves the use of MOVES2010 in official State implementation air quality plan (SIP) submissions to EPA and for certain transportation conformity analyses outside of California. This notice starts a two-year grace period before the MOVES2010 emission model is required to be used in new regional emissions analyses for transportation conformity determinations outside of California. EPA is not approving MOVES2010 for project-level transportation conformity hot-spot analyses at this time; the Agency will approve the model for such analyses in the near future in a separate **Federal Register** notice when guidance is finalized.

EPA strongly encourages areas to use the interagency consultation process to examine how MOVES2010 will affect future transportation plan and transportation improvement program (TIP) conformity determinations so, if necessary, SIPs and motor vehicle emissions budgets can be revised with MOVES2010 or transportation plans and TIPs can be revised as appropriate prior to the end of the MOVES2010 conformity grace period. EPA also encourages State and local air agencies to consider how the release of MOVES2010 will affect analyses supporting SIP submissions under development.

DATES: EPA's approval of the MOVES2010 emissions model for SIPs and regional emissions analyses for transportation conformity is effective March 2, 2010. As discussed further below, today's approval also starts a two-year transportation conformity grace period which ends on *March 2, 2012,* after which MOVES2010 is required to be used for new regional emissions analyses for transportation conformity.

FOR FURTHER INFORMATION CONTACT: For technical model questions regarding the official release or use of MOVES2010, please e-mail EPA at *mobile@epa.gov* or call (734) 214–4636. For questions about SIPs, contact Rudy Kapichak at *Kapichak.Rudolph@epa.gov* or (734) 214–4574. For transportation conformity questions, contact Meg Patulski at *Patulski.Meg@epa.gov* or (734) 214–4842.

SUPPLEMENTARY INFORMATION: The contents of this notice are as follows:

Availability of MOVES2010 and Support Materials

Copies of the official version of the MOVES2010 model, along with user guides and supporting documentation, are available on EPA's MOVES Web site: *http://www.epa.gov/otaq/models/moves/index.htm.*

Guidance on how to apply MOVES2010 for SIPs and transportation conformity purposes, including "Policy Guidance on the Use of MOVES2010 for State Implementation Plan Development, Transportation Conformity, and Other Purposes" (EPA–420–B–09–046, December 2009) and "Technical Guidance on the Use of MOVES2010 for Emission Inventory Preparation in State Implementation Plans and Transportation Conformity" (EPA–420–B–09–042, December 2009) can be found on the EPA's transportation conformity Web site at: *http://www.epa.gov/otaq/stateresources/transconf/policy.htm.*

EPA will continue to update this Web site as other MOVES support materials and guidance are developed.

Individuals who wish to receive EPA announcements related to the MOVES2010 model should subscribe to the EPA–MOBILENEWS e-mail listserver. To subscribe to the EPA–MOBILENEWS listserver, send a blank e-mail to EPA at *join-EPA-MOBILENEWS@lists.epa.gov.* Your e-mail address will then be added to the list of subscribers and a confirmation message will be sent to your e-mail address. Whenever a message is posted to the EPA–MOBILENEWS listserver by the listserver owner (the Assessment and Standards Division of EPA's Office of Transportation and Air Quality), a copy of that message will be sent to every person who has subscribed. You can remove yourself from the list by sending a blank e-mail to EPA at *leave-EPA-MOBILENEWS@lists.epa.gov.* This e-mail must be sent from the same e-mail address that you used to subscribe. For more information about the EPA–MOBILENEWS listserver, visit EPA's Web site at *http://www.epa.gov/otaq/models/mobilelist.htm.*

I. What Is MOVES2010?

MOVES2010 is the state-of-the-art upgrade to EPA's modeling tools for estimating emissions from highway vehicles, based on analysis of millions of emission test results and considerable advances in the Agency's understanding of vehicle emissions. Today's notice approves MOVES2010 as EPA's official motor vehicle emissions factor model for estimating volatile organic compounds (VOCs), nitrogen oxides (NO_X), carbon monoxide (CO), direct particulate matter (PM_{10} and $PM_{2.5}$) and other precursors from cars, trucks, buses, and motorcycles by State and local agencies for SIP purposes and regional emissions analyses for transportation conformity outside of California. For these purposes, MOVES2010 replaces the previous emissions model, MOBILE6.2, which was released in 2004 (69 FR 28830).[1]

MOVES2010 improves upon MOBILE6.2 in several key respects. For example, MOVES2010 is based on a review of the vast amount of in-use vehicle data collected and analyzed since the release of MOBILE6.2, including millions of emissions measurements from light-duty vehicles. Analysis of this data has enhanced EPA's understanding of how on-road mobile sources contribute to emissions inventories, and has also improved the agency's understanding of the relative effectiveness of various control strategies. MOVES2010 has a database-centered design that allows users much greater flexibility in organizing input and output data. This structure also allows EPA to update emissions data incorporated in MOVES2010 more easily.

MOVES2010 includes the capability to estimate vehicle exhaust and evaporative emissions as well as brake wear and tire wear emissions for criteria pollutants and precursors. However, MOVES2010 does not include the capability to estimate emissions of re-entrained road dust. To estimate emissions from re-entrained road dust, practitioners should continue to use the latest approved methodologies.[2]

II. SIP Policy for MOVES2010

EPA has articulated its policy regarding the use of MOVES2010 in SIP development in its "Policy Guidance on the Use of MOVES2010 for State Implementation Plan Development, Transportation Conformity, and Other Purposes" (EPA–420–B–09–046, December 2009). Today's notice highlights certain aspects of the guidance, but State and local governments should refer to the guidance for more detailed information on how and when to use MOVES2010 in reasonable further progress SIPs, attainment demonstrations, maintenance plans, inventory updates, and other SIP submission requirements.

Although MOVES2010 should be used in SIP development as expeditiously as possible, EPA also recognizes the time and effort that States have already undertaken in SIP development using MOBILE6.2. SIPs that EPA has already approved are not required to be revised solely based on existence of the new model. States that have already submitted SIPs or will submit SIPs shortly after EPA's approval of MOVES2010 are not required to revise these SIPs simply because a new motor vehicle emissions model is now available. States can choose to use MOVES2010 in these SIPs, for example, if it is determined that it is appropriate to update motor vehicle emissions budgets ("budgets") with the MOVES2010 model for future conformity determinations. However, EPA does not believe that a State's use of MOBILE6.2 should be an obstacle to EPA approval for SIPs that have been or will soon be submitted, assuming that such SIPs are otherwise approvable and significant SIP work has already occurred (*e.g.,* attainment modeling for an attainment SIP has already been completed with MOBILE6.2). It would be unreasonable in such cases to require States to revise these SIPs with MOVES2010 since significant work has already occurred, and EPA intends to act on these SIPs in a timely manner.

States should use MOVES2010 where SIP development is in its initial stages or hasn't progressed far enough along that switching to MOVES2010 would create a significantly adverse impact on State resources. For example, States (except California) that will be developing on-road mobile source inventories for 2006 24-hour $PM_{2.5}$ NAAQS SIPs should base those inventories on MOVES2010. EPA designated nonattainment areas for this NAAQS on November 13, 2009 (74 FR 58688), which should give State and local agencies time to incorporate MOVES2010 into SIP submissions for this NAAQS. MOVES2010 should be incorporated into these and other SIPs, as appropriate, since MOVES2010 emissions estimates are based on the best information currently available, as required by Clean Air Act section 172(c)(3) and 40 CFR 51.112(a)(1).

III. Transportation Conformity Policy for MOVES2010

EPA is establishing a two-year grace period before MOVES2010 is required for new transportation plan and TIP conformity determinations and regional emissions analyses. This grace period begins today and ends March 2, 2012. The remainder of this section describes how the transportation conformity grace period was determined and summarizes how it will be implemented, including those circumstances when the grace period could be shorter than two years. However, for complete explanations of how MOVES2010 is to be implemented for transportation conformity, including details about using MOVES2010 during the grace period, refer to "Policy Guidance on the Use of MOVES2010 for State Implementation Plan Development, Transportation Conformity, and Other Purposes" (EPA–420–B–09–046, December 2009). EPA coordinated closely with the U.S.

[1] Today's notice does not affect emissions model requirements within California, where the EMFAC2007 emissions model is currently approved for SIP purposes and for regional emissions analyses and CO hot-spot analyses for transportation conformity (73 FR 3464).

[2] *See* EPA's notice of availability published in the **Federal Register** on May 19, 2004, 69 FR 28830–28832. Also see EPA's memoranda: "Policy Guidance on the Use of the November 1, 2006, Updated to AP–42 for Re-entrained Road Dust for SIP Development and Transportation Conformity," August 2, 2007; and "Policy Guidance on the Use of MOBILE6.2 and the December 2003 AP–42 Method for Re-entrained Road Dust for SIP Development and Transportation Conformity," February 24, 2004. These documents are available on EPA's Web site at: *http://www.epa.gov/otaq/stateresources/transconf/policy.htm.*

Department of Transportation (DOT) in the establishment of the grace period.

A. Length of Conformity Grace Period

Transportation conformity is a Clean Air Act requirement to ensure that Federally supported highway and transit activities are consistent with ("conform to") the SIP. Conformity to a SIP means that a transportation activity will not cause or contribute to new air quality violations; worsen existing violations; or delay timely attainment of the national ambient air quality standards or any interim milestone. Transportation conformity applies in nonattainment and maintenance areas for transportation-related pollutants: ozone, carbon monoxide (CO), $PM_{2.5}$, PM_{10}, and nitrogen dioxide.

The transportation conformity rule (40 CFR parts 51 and 93) requires that conformity determinations be based on the latest motor vehicle emissions model approved by EPA. Section 176(c)(1) of the Clean Air Act states that "* * * [t]he determination of conformity shall be based on the most recent estimates of emissions, and such estimates shall be determined from the most recent population, employment, travel, and congestion estimates * * *." When EPA approves a new emissions model such as MOVES2010, a grace period is established before the model is required for conformity analyses. The conformity rule provides for a grace period for new emissions models of between three and 24 months (40 CFR 93.111(b)(1)).

EPA articulated its intentions for establishing the length of a conformity grace period in the preamble to the 1993 transportation conformity rule (58 FR 62211):

> EPA and DOT will consider extending the grace period if the effects of the new emissions model are so significant that previous SIP demonstrations of what emission levels are consistent with attainment would be substantially affected. In such cases, States should have an opportunity to revise their SIPs before MPOs [metropolitan planning organizations] must use the model's new emissions factors.

In consultation with DOT, EPA must consider many factors when establishing a grace period for conformity determinations, including the degree of change in emissions models and the effects of the new model on the transportation planning process (40 CFR 93.111(b)(2)).

Upon consideration of all of these factors, EPA is establishing a two-year grace period, which begins today and ends on March 2, 2012, before MOVES2010 is required to be used for regional transportation conformity purposes. During this grace period, areas should use the interagency consultation process to examine the impact of using MOVES2010 in their future transportation plan and TIP conformity determinations and regional emissions analyses.

B. Circumstances When Grace Period Will Be Shorter Than Two Years

The grace period will be shorter than two years for a given pollutant if an area revises its SIP and budgets with MOVES2010, and such budgets become applicable for regional conformity purposes prior to the end of the two-year grace period. In this case, the new regional emissions analysis must use MOVES2010 if the conformity determination is based on a MOVES2010-based budget.

Areas that are designated nonattainment or maintenance for multiple pollutants may rely on both MOVES2010 and MOBILE6.2 to determine conformity for different pollutants during the grace period. For example, if an area revises a previously submitted (but not approved) MOBILE6.2-based PM_{10} SIP with MOVES2010 and EPA finds these revised MOVES2010 budgets adequate for conformity, such budgets would apply for conformity on the effective date of the **Federal Register** notice announcing EPA's adequacy finding. In this example, if an area was in nonattainment for PM_{10} and ozone, the MOVES2010 grace period would end for PM_{10} once EPA found the new MOVES2010-based SIP budgets adequate. However, MOBILE6.2 could continue to be used for ozone conformity determinations until the end of the MOVES2010 grace period.[3] EPA Regional Offices should be consulted for questions regarding such situations in multi-pollutant areas.

In addition, if an area revises a previously approved SIP using MOVES2010, the revised MOVES2010 budgets would be used for conformity purposes once EPA approves the MOVES2010 SIP revision, in most cases. In general, submitted SIPs cannot supersede approved budgets until they are approved. However, 40 CFR 93.118(e)(1) allows an approved budget to be replaced by an adequate budget if EPA's approval of the initial budgets specifies that the budgets being approved may be replaced in the future by new adequate budgets. This flexibility has been used in limited situations in the past, such as during the transition from MOBILE5 to MOBILE6. In such cases, the MOVES2010-based budgets would be used for conformity purposes once they have been found adequate, if requested by the State in its SIP submission and specified in EPA's SIP approval. States should consult with their EPA Regional Office to determine if this flexibility applies to their situation.

C. Use of MOVES2010 During the Grace Period

During the conformity grace period, areas should use the interagency consultation process to examine how MOVES2010 will impact their future transportation plan and TIP conformity determinations and any regional emissions analyses. Areas should carefully consider whether the SIP and budgets should be revised with MOVES2010 or if transportation plans and TIPs should be revised before the end of the conformity grace period, since doing so may be necessary to ensure conformity in the future.

Regional emissions analyses that are started during the grace period can use either MOBILE6.2 or MOVES2010. When the grace period ends on March 2, 2012, MOVES2010 will become the only approved motor vehicle emissions model for regional emissions analyses for transportation conformity in States other than California. In general, this means that all new transportation plan and TIP conformity determinations started after the end of the grace period must be based on MOVES2010, even if the SIP is based on MOBILE6.2.

Finally, the conformity rule provides some flexibility for regional emissions analyses that are started before the end of the grace period. Analyses that begin before or during the grace period may continue to rely on MOBILE6.2. The interagency consultation process should be used if it is unclear if a MOBILE6.2-based analysis was begun before the end of the grace period. If you have questions about which model should be used in your conformity determination, you can also consult with your EPA Regional Office.

IV. Future Notice Approving MOVES2010 for Project-level Conformity Hot-spot Analyses

Today's notice does not approve MOVES2010 for use in transportation conformity hot-spot analyses in $PM_{2.5}$, PM_{10}, and CO nonattainment and

[3] In this example, such an area would use MOVES2010 to develop a regional emissions analysis for comparison to the revised MOVES2010-based budgets (*e.g.,* PM_{10} and NOx budgets). The regional emissions analysis for ozone could be based on MOBILE6.2 for the VOC and NOx budgets in the ozone SIP for the remainder of the conformity grace period.

maintenance areas.[4] EPA will approve MOVES2010 for these purposes, and establish a separate two-year conformity grace period, in a subsequent **Federal Register** notice. Details on how EPA intends to implement MOVES2010 for quantitative CO, $PM_{2.5}$, and PM_{10} hot-spot analyses can be found in "Policy Guidance on the Use of MOVES2010 for State Implementation Plan Development, Transportation Conformity, and Other Purposes" (EPA–420–B–09–042, December 2009).

Dated: February 24, 2010.

Margo Tsirigotis Oge,

Director, Office of Transportation and Air Quality.

[FR Doc. 2010–4312 Filed 3–1–10; 8:45 am]

BILLING CODE 6560–50–P

EXPORT-IMPORT BANK OF THE UNITED STATES

Notice of Open Meeting of the Advisory Committee of the Export-Import Bank of the United States (Ex-Im Bank)

SUMMARY: The Advisory Committee was established by Public Law 98–181, November 30, 1983, to advise the Export-Import Bank on its programs and to provide comments for inclusion in the reports of the Export-Import Bank of the United States to Congress.

TIME AND PLACE: Friday, March 12, 2010 beginning at 2:30 p.m. The meeting will be held in the Palladian Room at the Onmi Shoreham Hotel, 2500 Calvert Street, NW., Washington, DC 20008.

Agenda: Agenda items include a briefing on the status of the 2010 Advisory Committee's Subcommittees and the challenges for 2010.

Public Participation: The meeting will be open to public participation, and the last 10 minutes will be set aside for oral questions or comments. Members of the public may also file written statement(s) before or after the meeting. If any person wishes auxiliary aids (such as a sign language interpreter) or other special accommodations, please contact, prior to March 3, 2010, Susan Houser, Room 1273, 811 Vermont Avenue, NW., Washington, DC 20571, *Voice:* (202) 565–3232 or TDD (202) 565–3377.

FOR FURTHER INFORMATION CONTACT: For further information, contact Susan Houser, Room 1273, 811 Vermont Ave., NW., Washington, DC 20571, (202) 565–3232.

Jonathan Cordone,

Senior Vice President and General Counsel.

[FR Doc. 2010–4208 Filed 3–1–10; 8:45 am]

BILLING CODE 6690–01–M

FARM CREDIT ADMINISTRATION

Farm Credit Administration Board; Sunshine Act; Regular Meeting

AGENCY: Farm Credit Administration.

SUMMARY: Notice is hereby given, pursuant to the Government in the Sunshine Act (5 U.S.C. 552b(e)(3)), of the regular meeting of the Farm Credit Administration Board (Board).

DATE AND TIME: The regular meeting of the Board will be held at the offices of the Farm Credit Administration in McLean, Virginia, on March 11, 2010, from 9 a.m. until such time as the Board concludes its business.

FOR FURTHER INFORMATION CONTACT: Roland E. Smith, Secretary to the Farm Credit Administration Board, (703) 883–4009, TTY (703) 883–4056.

ADDRESSES: Farm Credit Administration, 1501 Farm Credit Drive, McLean, Virginia 22102–5090.

SUPPLEMENTARY INFORMATION: This meeting of the Board will be open to the public (limited space available). In order to increase the accessibility to Board meetings, persons requiring assistance should make arrangements in advance. The matters to be considered at the meeting are:

Open Session

A. Approval of Minutes

- February 24, 2010

B. New Business

- Director Elections—Final Rule

C. Reports

- Office of Management Services Quarterly Report

Dated: February 25, 2010.

Roland E. Smith,

Secretary, Farm Credit Administration Board.

[FR Doc. 2010–4348 Filed 2–26–10; 11:15 am]

BILLING CODE 6705–01–P

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisition of Shares of Bank or Bank Holding Companies

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal Reserve Bank indicated. The notices also will be available for inspection at the office of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than March 17, 2010.

A. Federal Reserve Bank of Atlanta (Steve Foley, Vice President) 1000 Peachtree Street, N.E., Atlanta, Georgia 30309:

1. Anthony Jennings Roy, III, Marksville, Louisiana; to retain voting shares of Mansura Bancshares, Inc., Mansura, Louisiana, and thereby indirectly retain voting shares of The Cottonport Bank, Cottonport, Louisiana.

Board of Governors of the Federal Reserve System, February 25, 2010.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. 2010–4225 Filed 3–1–10; 8:45 am]

BILLING CODE 6210–01–S

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR Part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. The applications also will be available for inspection at the offices of

[4] In CO nonattainment and maintenance areas, a hot-spot analysis is required for all non-exempt projects, with quantitative hot-spot analyses being required for larger, congested intersections and other projects (40 CFR 93.123(a)(1)). In addition, the conformity rule requires that a quantitative PM_{10} or $PM_{2.5}$ hot-spot analysis be completed for certain projects of local air quality concern once EPA releases modeling guidance and announces in the **Federal Register** that the PM_{10} and $PM_{2.5}$ quantitative hot-spot analysis requirements are in effect (40 CFR 93.123(b)). In coordination with DOT, EPA is currently preparing guidance on how to conduct quantitative $PM_{2.5}$ and PM_{10} hot-spot modeling to implement this requirement.

Federal Register

Thursday,
April 14, 2005

Part II

Environmental Protection Agency

40 CFR Part 81

Air Quality Designations for the Fine Particles (PM2.5) National Ambient Air Quality Standards—Supplemental Amendments; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 81

[OAR–2003–0061; FRL–7896–8]

RIN–2060–AM04

Air Quality Designations for the Fine Particles (PM2.5) National Ambient Air Quality Standards—Supplemental Amendments

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; supplemental amendments.

SUMMARY: On January 5, 2005, EPA promulgated air quality designations for all areas for the national ambient air quality standards (NAAQS) for fine particles (*i.e.* particles less than 2.5 microns in diameter, also known as PM2.5) (70 FR 944). We designated 47 areas composed of 224 counties and the District of Columbia as nonattainment. We designated 5 areas comprised of 7 counties as unclassifiable. We designated the remaining counties in the United States as attainment/unclassifiable. We based the designations in the January 5, 2005, final rule on air quality monitoring data from the 3-year period of 2001 to 2003. In that action, we provided that these designations would be effective 90 days from the date of publication in the **Federal Register**, which is April 5, 2005. Because the designations occurred at the end of 2004, we indicated our desire to consider 2004 data where feasible in order to evaluate attainment status based upon data from the 3-year period of 2002 to 2004. We explained that we would consider any complete, quality-assured, and certified 2004 PM2.5 data submitted by any State to EPA by February 22, 2005, if such data indicated that a change in the designation for the entire area would be appropriate.

In the January 5, 2005, action, we stated that if EPA agreed that a change in the designation was appropriate based upon the inclusion of 2004 data, then EPA would withdraw the initial designation for the area and issue a designation that reflected the consideration of the new data before the April 5, 2005, effective date. Today's action addresses areas for which States have submitted complete, quality-assured, and certified PM2.5 air quality data for 2004, and it modifies the designation status to attainment for eight areas we originally designated as nonattainment and for four areas we originally designated as unclassifiable. This action also includes technical corrections related to boundary descriptions for a few areas included in the January 5, 2005, action. The EPA has received a number of other petitions in connection with the PM2.5 designations pertaining to issues other than inclusion of 2004 data as a basis for changing the designation prior to the effective date. The EPA is not responding to those petitions in this document and will be evaluating and responding to those petitions separately.

DATES: Effective upon April 5, 2005.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. OAR–2003–0061. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket*. Although listed in the index, some information is not publicly available, *i.e.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in the EDOCKET or in hard copy at the Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m. Monday through Friday, excluding legal holidays. The telephone number for the public Reading Room is (202) 566–1744, and the telephone number for the Office of Air and Radiation Docket and Information Center is (202) 566–1742. In addition, we have placed a copy of the rule and a variety of materials regarding designations on EPA's designation Web site at: *http://www.epa.gov/oar/oaqps/particles/designations/index.htm* and on the Tribal Web site at: *http://www/epa.gov/air/tribal*.

FOR FURTHER INFORMATION CONTACT:

Designations: Mr. Rich Damberg, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Mail Code C504–02, Research Triangle Park, NC 27711, phone number (919) 541–5592 or by e-mail at: *damberg.rich@epa.gov*.

Designations and Part 81 Code of Federal Regulations (CFR): Larry D. Wallace, Ph.D., U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Mail Code C504–02, Research Triangle Park, NC 27711, phone number (919) 541–0906 or by e-mail at: *wallace.larry@epa.gov*.

Technical Issues Related to Designations: Mr. Thomas Rosendahl, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Mail Code C504–02, Research Triangle Park, NC 27711, phone number (919) 541–5314 or by e-mail at: *rosendahl.tom@epa.gov*.

PM2.5 Air Quality Data Issues: Mr. Mark Schmidt, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Mail Code C–304–01, Research Triangle Park, NC 27711, phone number (919) 541–5314 or by e-mail at: *schmidt.mark@epa.gov*.

Region I—Alison Simcox (617) 918–1684,

Region II—Kenneth Fradkin (212) 637–3702,

Region III—Denny Lohman (215) 814–2192,

Region IV—Steve Scofield (404) 562–9034,

Region V—John Summerhays (312) 886–6067,

Region VI—Joe Kordzi (214) 665–7186,

Region VII—Amy Algoe-Eakin (913) 551–7942,

Region VIII—Libby Faulk (303) 312–6083,

Region IX—Eleanor Kaplan (415) 744–1286,

Region X—Keith Rose (206) 553–1949.

SUPPLEMENTARY INFORMATION: The public may inspect the rule and the technical support information at the following locations:

Regional offices	States
Dave Conroy, Acting Branch Chief, Air Programs Branch, EPA New England, I Congress Street, Suite 1100, Boston, MA 02114–2023, (617) 918–1661.	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
Raymond Werner, Chief, Air Programs Branch, EPA Region II, 290 Broadway, 25th Floor, New York, NY 10007–1866, (212) 637–4249.	New Jersey, New York, Puerto Rico, and Virgin Islands.
Makeba Morris, Branch Chief, Air Quality Planning Branch, EPA Region III, 1650 Arch Street, Philadelphia, PA 19103–2187, (215) 814–2187.	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, and West Virginia.

Regional offices	States
Richard A. Schutt, Chief, Regulatory Development Section, EPA Region IV, Sam Nun Atlanta Federal Center, 61 Forsyth Street, SW., 12th Floor, Atlanta, GA 30303, (404) 562–9033.	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee.
Jay Bortzer, Chief, Air Programs Branch, EPA Region V, 77 West Jackson Street, Chicago, IL 60604, (312) 886–4447.	Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.
Donna Ascenzi, Acting Associate Director Air Programs, EPA Region VI, 1445 Ross Avenue, Dallas, TX 75202, (214) 665–2725.	Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.
Joshua A. Tapp, Chief, Air Programs Branch, EPA Region VII, 901 North 5th Street, Kansas City, Kansas 66101–2907, (913) 551–7606.	Iowa, Kansas, Missouri, and Nebraska.
Richard R. Long, Director, Air and Radiation Program, EPA Region VIII, 999 18th, Suite 300, Denver, CO 80202, (303) 312–6005.	Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming.
Steven Barhite, Air Planning Office, EPA Region IX, 75 Hawthorne Street, San Francisco, CA 94105, (415) 972–3980.	Arizona, California, Guam, Hawaii, and Nevada.
Mahbubul Islam, Manager, State and Tribal Air Programs, EPA Region X, Office of Air, Waste, and Toxics, Mail Code OAQ–107, 1200 Sixth Avenue, Seattle, WA 98101, (206) 553–6985.	Alaska, Idaho, Oregon, and Washington.

Table of Contents

The following is an outline of the Preamble.

I. What Is the Purpose of Today's Action?

On January 5, 2005, EPA promulgated air quality designations for all areas in the United States for the NAAQS for PM2.5 (70 FR 944), in accordance with section 107(d) of the Clean Air Act (CAA). The list of areas in each State, the boundaries of each area, and the designation of each area, appear in a table at the end of that action. The purpose of today's action is to modify the PM2.5 designation for a number of areas that we designated nonattainment or unclassifiable in the January 5, 2005 action, and to make certain technical corrections to the table of areas described in 40 CFR part 81.

The January 5, 2005, PM2.5 designations were based on air quality data for 2001 through 2003. We designated 47 areas comprised of 224 counties and the District of Columbia were designated as nonattainment. We designated 5 areas comprised of 7 counties as unclassifiable. We designated the remaining counties in the United States as attainment/unclassifiable. We based the designations in the January 5, 2005, action on air quality monitor data from the 3-year period of 2001 to 2003. The action provided that these designations would be effective 90 days from the date of publication (*i.e.* April 5, 2005).

Because the designation process occurred so close to the end of the 2004 calendar year, EPA indicated that we would consider any complete, quality-assured, and certified PM2.5 data for 2004 submitted by any State by February 22, 2005, if such data indicated that the attainment status for the entire area, based on 2002–2004 data, would differ from the status indicated in the January 5 action. In other words, we indicated that the agency would consider changing the designation status of an area from nonattainment to attainment, or unclassifiable to attainment, if *each* monitor in the initially designated area had air quality data for the 2002–2004 period below the level of the standards.

The EPA received complete, quality-assured, and certified air quality data for 2004 from a number of States prior to February 22, 2005. Based on our evaluation of this data, in today's action, EPA is changing the designation status from nonattainment to attainment for eight areas, and from unclassifiable to attainment for four areas. Today's modifications to the initial designations for these areas do not represent ''redesignations'' because these changes are being made prior to the effective date of the initial PM2.5 designations. We are making these changes to reflect the most recent 3 years of complete, quality-assured, and certified data that are available prior to the effective date of the designations. After April 5, 2005, any change in the PM2.5 designation status for an area, other than those that might result from a petition for reconsideration or error correction, would be subject to the redesignation provisions of section 107(d)(3) of the CAA.

In the January 5, 2005, action, we also stated that if certified 2004 data indicated a violation of the standard in an area we initially designated as attainment based on 2001–2003 data, EPA would evaluate the reason for the violation and determine the appropriate course of action, including the possibility of redesignation to nonattainment. No States submitted certified 2004 data by February 22, 2005, to indicate that the status of any area should change from attainment or unclassifiable to nonattainment. The EPA has committed to evaluate all 2004 data for areas initially designated as unclassifiable. Under existing regulations, States are required to certify air quality data for 2004 by July 1, 2005. At that time, EPA will evaluate whether a change of designation for an unclassifiable area is appropriate.

II. Designation Decisions Based on 2002–2004 Data

Areas changing from nonattainment to attainment based on 2002–2004 data. A number of States, including AL, CA, GA, IN, KY, OH, PA, TN, and WV, submitted certified 2004 air quality monitoring data to EPA by February 22, 2005. (All correspondence from States related to this action can be found in docket OAR–2003–0061 for this action.) Based upon our technical evaluation of the certified 2004 data provided by these States, we have determined that the nonattainment designation for seven areas listed in the January 5 action (based on 2001–2003 data) should be changed to attainment (based on 2002–

2004 data). In each of these areas, all PM2.5 monitors have complete, quality-assured, and certified data below the level of the PM2.5 standards for the 2002–2004 period. These seven areas are:

—Athens, Georgia (Clarke county);
—Elkhart, Indiana (Elkhart and St. Joseph's counties);
—Lexington, Kentucky (Fayette and Mercer counties);
—Marion county, WV (Marion, Monangalia, and Harrison counties);
—San Diego, California (San Diego county);
—Toledo, Ohio (Lucas and Wood counties); and
—Youngstown, OH-PA (Columbiana, Mahoning, and Trumbull counties, Ohio; Mercer county, Pennsylvania).

(A summary of the air quality data for these areas is included in the technical support document for this action. Comprehensive information for these areas is available from EPA's Air Quality Subsystem at: *http://www.epa.gov/ttn/airs/airsaqs/index.htm*.)

Areas changing from unclassifiable to attainment based on 2002–2004 data. In addition, we have determined that for four areas the unclassifiable designation in the January 5 action (based on 2001–2003 data) should now be changed to attainment (based on 2002–2004 data). In each of these areas, all PM2.5 monitors have complete, quality-assured, and certified data below the level of the PM2.5 standards for the 2002–2004 period. These four areas are:

—Dekalb county, Alabama;
—Gadsden, Alabama (Etowah county);
—McMinn county, Tennessee; and
—Muncie, Indiana (Delaware county).

(A summary of the air quality data for these areas is included in the technical support document for this action. Comprehensive information for these areas is available from EPA's Air Quality Subsystem at: *http://www.epa.gov/ttn/airs/airsaqs/index.htm*.)

For all of the areas changing from either nonattainment or unclassifiable to attainment based upon the consideration of 2004 data, EPA has determined that it is appropriate to revise the initial designation announced in the January 5, 2005, action before the April 5, 2005, effective date. The EPA believes that the specific redesignation requirements of the CAA, including those set forth in section 107(d)(3)(E), do not apply until after the effective date of a designation. The EPA has concluded that, where possible, inclusion of 2004 data results in the appropriate initial designation. Subsequent changes to the designation of these or other areas may require compliance with the statutory provisions governing the formal redesignation process.

Requests to change individual counties to attainment. The EPA received requests from a number of States to change the status of a selected county within a larger nonattainment area from nonattainment to attainment based upon 2004 data. For five counties in four nonattainment areas (see table below), States submitted certified 2004 data showing that the 2002–2004 value for all monitors in the specific county at issue is below the level of the PM2.5 annual standard. In each of these situations, however, there are other monitors in the larger nonattainment area identified in the January 5, 2005 action which continue to violate the annual standard based on 2002–2004 data. The following table lists the State and county in question, the associated nonattainment area, and the other violating county in the area.

State	County	PM2.5 nonattainment area	Other county in area violating with 2002–2004 data
Indiana	Lake	Chicago	Cook County, IL
Indiana	Vanderburgh	Evansville	Dubois County, IN
Michigan	Monroe	Detroit	Wayne County, IL
Ohio	Scioto, Lawrence	Huntington, WV-OH	Cabell County, WV

The EPA indicated in the January 5 action that we would make changes in status from nonattainment to attainment based on certified 2004 data *only* for entire areas in which all PM2.5 monitors were attaining: ''If inclusion of 2004 data causes an area to change from nonattainment to attainment, EPA will change the designation if every county in the area is neither monitoring a violation of the standards nor contributing to a violation of the standards in another nearby area.'' In addition, EPA has examined the data and concluded that each of these counties continues to contribute to the overall air quality problem in the larger nonattainment area. As explained in the January 5, 2005 action, EPA has designated as nonattainment not only those counties with violating monitors, but also those nearby counties that contribute to the problem at the violating monitor. For these reasons, EPA is not changing the designation status for Lake and Vanderburgh Counties in Indiana, Monroe County in Michigan, and Scioto and Lawrence Counties in Ohio. The technical support document for this action includes additional discussion on each of these individual counties and nonattainment areas.

Also, EPA received a number of petitions from States and local governments that did not meet our request for submission of 2004 data indicating that a change of designation was appropriate for the entire area. In general, these petitions pertained to the degree of contribution to nonattainment of one or more counties within a nonattainment area or to the boundaries of specific nonattainment areas. The EPA is evaluating these petitions and intends to respond to them separately at a later date.

Chattanooga, TN request to invalidate multiple monitoring samples and change status to attainment. The Chattanooga-Hamilton County Air Pollution Control Bureau and the State of Georgia have submitted requests to EPA to invalidate samples for 25 days at monitors in Hamilton County, TN and Walker County, GA. They based their requests on claims that these sites were impacted by various fire events occurring in locations such as Kansas, Alaska, and Canada. Chattanooga claimed that if all such days were invalidated, then the Hamilton County, TN monitors would have incomplete data and could not remain designated as nonattainment. Georgia contended that if these samples were invalidated, the Walker County, GA monitor would then attain the standards. In addition, Georgia has maintained that if Walker County attains the standard, then the status for Catoosa County should be changed to attainment because the State claims its contribution to nonattainment does not extend to Hamilton County, TN. The EPA has concluded that Catoosa County contributes to both Hamilton and Walker Counties based upon evaluation of the factors applied

by EPA in the initial designation decision (particularly population, commuting, and emissions) as discussed in the original technical support document.

We have reviewed the data for the 25 days in question and the supporting information provided by local and State agencies for the Chattanooga area. Previously, EPA disapproved the request to invalidate 10 days in 2002. For the 15 days in 2003 and 2004 requested by Chattanooga to be invalidated due to fire impacts, EPA has determined that there is insufficient evidence to show impacts from the fire events for at least 7 of these days, and is disapproving the requests to invalidate air quality data for those days. This determination is based on EPA's review of the supporting information provided to EPA, as well as additional analyses conducted by EPA. These analyses include back trajectories and a review of chemical composition data for the area, and they are available in the technical support document and docket for this action.

The EPA has determined that it is not necessary to reach a final conclusion with respect to the remaining 8-flagged days. Even if it were appropriate to invalidate the data from all of the remaining days, the monitor in Hamilton County, TN would still violate the PM2.5 standards for 2002–2004 with a design value of 15.4. Assuming invalidation of all 7 days, the monitor in Walker County, GA would attain the standard at 14.8. However, even though the Walker County monitor would be below the level of the standard, we continue to conclude that Walker County contributes to the nonattainment problem at the Hamilton County, TN monitor, thus requiring the inclusion of that county in the nonattainment area.

Thus, even if it was appropriate to invalidate all of the remaining 8-flagged days, EPA has determined that at least one county in the Chattanooga nonattainment area would continue to have a violating monitor. As stated in the January 5, 2005, action, we indicated that it might be appropriate to change the nonattainment designation of an area only if all monitors in the area show attainment. Because there is a continuing violation at one monitor in the area, and because there is continued contribution from the other counties to the violating monitor, EPA has determined that the area still would violate the standard even if all additional flagged days were invalidated. Moreover, any uncertainty concerning the possible invalidation of the remaining flagged days is not an appropriate basis for designating this area unclassifiable. That designation is reserved for those areas where EPA lacks sufficient information upon which to make a judgment whether or not the area is attaining the PM2.5 NAAQS. In this instance, given that invalidation of the remaining flagged days would not change the outcome, the area does not meet the NAAQS. For this reason, EPA is not modifying the nonattainment status of Hamilton County in Tennessee or Walker or Catoosa Counties in Georgia.

Columbus, GA-AL: Request for spatial averaging and request for attainment based on 2002–2004 data.

Any State or States requesting spatial averaging of PM2.5 monitoring sites must demonstrate that the sites meet several criteria as described in EPA regulations (40 CFR part 58.). First, the annual mean for each site must be within 20 percent of the annual mean calculated with spatial averaging. Second, the sites must show ''similar day-to-day variability'' (*e.g.*, 0.60 correlation). Third, the States must demonstrate that the sites are affected by the same emissions sources. Fourth, the States must provide adequate notice to the public of the proposed change in the monitoring plan and potential effect on attainment status, including a public hearing and opportunity for public comment.

In June 2004, the States of Georgia and Alabama submitted proposed changes to their monitoring plans to conduct spatial averaging for three monitoring sites in the Columbus, GA-AL area (two in Muscogee County, GA and one in Russell County, AL). In November 2004, EPA denied the request for spatial averaging on the basis that: (1) the submittal did not provide a basis for a 3-site community monitoring zone, and (2) the information did not demonstrate that all monitors were impacted by similar emissions sources. The letter also questioned the validity of several samples collected at the Russell county site during 2001 and 2002.

In December 2004, both States submitted revised monitoring plans requesting spatial averaging for the two downtown monitoring sites, one in Muscogee County, GA and one in Russell County, AL. In February 2005, both States submitted certified 2004 data for the two sites in question, and they also requested a change in status from nonattainment to attainment for the area, provided that EPA approved their pending spatial averaging request and that 2002–2004 data for the two sites could be averaged.

The EPA has conducted an extensive technical review of the information provided by both States to support the most recent spatial averaging proposals. Based on our review of a number of factors, we are approving the spatial averaging request. We also have determined that when 2002–2004 air quality data for the two sites are averaged, the Columbus, GA-AL metropolitan area now attains the PM2.5 standards. The spatial average for 2002–2004 is just under the standard at a level of 15.04.

In evaluating the spatial averaging proposals, EPA considered a number of factors in accordance with the PM2.5 NAAQS and PM2.5 monitoring regulations. The two monitors (one operated in Phenix City by AL and one in Columbus by GA) are less that 2 km apart. Both monitors are located in the inner city and are influenced by similar emission sources. The 3-year design value for each site is within ±2 percent of the new approved spatial average design value of 15.04. Furthermore, the monitors exhibit similar day-to-day variability indicated by a 0.85 correlation of 24-hr concentrations.

However, EPA also notes that annual concentrations at the two monitors are trending upward, with each site recording its highest annual average concentration in 2004. The 2004 average for these monitors is 15.4 $\mu g/m^3$. The EPA also notes that the monitors exhibit the highest disparity in their 24-hr concentrations during the 1st calendar quarter. Therefore, EPA will continue to monitor the PM2.5 measurements particularly during the winter period to ensure that we have a continuing understanding of any air quality changes that may occur in the future.

Therefore, for the above reasons and others discussed in the technical support document, EPA is approving the December 2004 2-site spatial averaging plan for the Columbus, GA-AL nonattainment area in today's action. It is therefore appropriate to change the designation of Muscogee County, GA and Russell County, AL from nonattainment to attainment. Please refer to the technical support document for more detailed information on EPA's review of the spatial averaging plan for this area.

III. Technical Corrections for Area Boundaries

In today's rule, EPA is also making minor technical corrections to certain attainment area boundary descriptions included in the January 5 action. Technical corrections for boundaries listed in 40 CFR part 81 are included for the following areas: (1) The State of Louisiana to correct the listings for air quality control region 106, (2) the boundary description for Placer County,

CA, (3) a change to the boundary description for Randolph County, IL to change Baldwin Village to Baldwin Township, and (4) the boundary description for Gallia County, OH to remove Addison Township and to include Cheshire Township. These corrections are being made to provide an accurate description of the boundaries for the affected areas as previously submitted to EPA by the States and/or included in the January 5 technical support document. In the January 5, 2005, action, these errors were inadvertently made in the process of drafting the text for the part 81 tables. The corrections made by EPA in today's rule are listed in the tables at the end of this notice, and these changes will be reflected in a revision of 40 CFR part 81.

IV. Significance of Today's Action

Based on the foregoing discussion, EPA is today making changes to the January 5, 2005 (70 FR 944), rulemaking which designated areas for the PM2.5 NAAQS. The corrections made by EPA in today's rule, related to the designations for the PM2.5 standard, are set forth in the tables at the end of this notice, and will change the designation description for the affected areas in 40 CFR part 81 initially announced in the January 5, 2005, action. States with areas designated as nonattainment for the PM2.5 NAAQS are required to submit State Implementation Plans (SIPs) addressing nonattainment area requirements within 3 years of designation, pursuant to section 172 of the CAA. Therefore, within 3 years following the April 5, 2005, effective date for the designations identified in the January 5, 2005 (70 FR 944), rulemaking, States will be required to submit SIPs for nonattainment areas. The EPA intends to issue another rule that will assist States in developing SIPs that meet the requirements of the CAA. The EPA plans to issue the proposal for that rulemaking in the near future.

V. Effective Date of Today's Action

The effective date of designations of areas corrected or changed in today's rule is April 5, 2005, the date indicated in the January 5, 2005 (70 FR 944), PM2.5 designation rulemaking. The EPA is making these changes without notice and comment in accordance with section 107(d)(2) of the CAA, which exempts the promulgation of these designations from the notice and comment provisions of the Administrative Procedures Act. Section 553(d) of the Administrative Procedures Act generally provides that rulemakings shall not be effective less than 30 days after publication except where a substantive rule relieves a restriction or where the agency finds good cause for an earlier date. 5 U.S.C. 553(d)(1) and (3). Were EPA not to expedite the effective date of today's action, a number of areas would continue to be designated nonattainment or unclassifiable, in spite of 2004 data that indicate a change of designation is appropriate. Because EPA has concluded that a change of designation is already appropriate based on available information, EPA believes that it would serve no purpose to require the States in question to pursue redesignation through other means that may result in delay and the unnecessary expenditure of resources. The effective date for today's action is therefore justified because: (1) It relieves a restriction by eliminating a restriction by eliminating inappropriate nonattainment or unclassifiable designations that would otherwise become effective on April 5, 2005, and (2) it is in the public interest to avoid the potential delay and waste of resources associated with allowing the January 5, 2005 designations to go into effect for these areas.

VI. Statutory and Executive Order Reviews

Upon promulgation of a new or revised NAAQS, the CAA requires EPA to designate areas with respect to their attainment of such NAAQS. The CAA imposes requirements for areas based upon whether such areas are attaining or not attaining the NAAQS. In this final rule, EPA assigns designations to areas as required.

A. Executive Order 12866: Regulatory Planning and Review.

Under Executive Order 12866 (58 FR 51735, October 4, 1993), EPA must determine whether the regulatory action is ''significant'' and, therefore, subject to the Office of Management and Budget (OMB) review and the requirements of the Executive Order. The order defines ''significant regulatory action'' as one that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities; (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is not a ''significant regulatory action'' because none of the above factors apply. As such, this final rule was not formally submitted to OMB for review.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* This rule responds to the requirement to promulgate air quality designations after promulgation of a NAAQS. This requirement is prescribed in the CAA section 107 of title 1. The present final rule does not establish any new information collection apart from that required by law. Burden means that total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in the CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

Today's rule is not subject to the Regulatory Flexibility Act (RFA), which generally requires an agency to prepare a regulatory flexibility analysis for any rule that will have a significant economic impact on a substantial number of small entities. The RFA applies only to rules subject to notice and comment rulemaking requirements under the Administrative Procedure Act (APA) or any other statute. This rule is not subject to notice and comment requirements under the APA or any other statute because it was not subject to notice and comment rulemaking requirements. *See* CAA section 107(d)(2)(B).

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal Agencies to assess the effects of their regulatory actions on State, local and Tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation of why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small government on compliance with regulatory requirements.

Today's final action does not include a Federal mandate within the meaning of UMRA that may result in expenditures of $100 million or more in any 1 year by either State, local, or Tribal governments in the aggregate or to the private sector, and therefore, is not subject to the requirements of sections 202 and 205 of the UMRA. It does not create any additional requirements beyond those of the PM2.5 NAAQS (62 FR 38652; July 18, 1997), therefore, no UMRA analysis is needed. This rule establishes the application of the PM2.5 standard and the designation for each area of the country for the PM2.5 NAAQS. The CAA requires States to develop plans, including control measures, based on their designations and classifications.

One mandate that may apply as a consequence of this action to all designated nonattainment areas is the requirement under CAA section 176(c) and associated regulations to demonstrate conformity of Federal actions to SIPs. These rules apply to Federal agencies and Metropolitan Planning Organizations (MPOs) making conformity determinations. The EPA concludes that such conformity determinations will not cost $100 million or more in the aggregate.

The EPA believes that any new controls imposed as a result of this action will not cost in the aggregate $100 million or more annually. Thus, this Federal action will not impose mandates that will require expenditures of $100 million or more in the aggregate in any 1 year.

Nonetheless, EPA carried out consultation with government entities affected by this rule, including States, Tribal governments, and local air pollution control agencies.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, or the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The CAA establishes the scheme whereby States take the lead in developing plans to meet the NAAQS. This rule will not modify the relationship of the States and EPA for purposes of developing programs to implement the NAAQS. Thus, Executive Order 13132 does not apply to this rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.'' This final rule does not have ''Tribal implications'' as specified in Executive Order 13175. This rule concerns the designation and classification of areas as attainment and nonattainment for the PM2.5 air quality standard. The CAA provides for States to develop plans to regulate emissions of air pollutants within their jurisdictions. The Tribal Authority Rule (TAR) provides Tribes the opportunity to develop and implement CAA programs such as programs to attain and maintain the PM2.5 NAAQS, but it leaves to the discretion of the Tribe the decision of whether to develop these programs and which programs, or appropriate elements of a program, the Tribe will adopt.

This final rule does not have Tribal implications as defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes, since no Tribe has implemented a CAA program to attain the PM2.5 NAAQS at this time. Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the Federal government and Indian Tribes. The CAA and the TAR establish the relationship of the Federal government and Tribes in developing plans to attain the NAAQS, and this rule does nothing to modify that relationship. Because this rule does not have Tribal implications, Executive Order 13175 does not apply.

Although Executive Order 13175 does not apply to this rule, EPA did outreach to Tribal leaders and environmental staff regarding the designations process. The EPA supports a national ''Tribal Designations and Implementation Work Group'' which provides an open forum for all Tribes to voice concerns to EPA about the designations and implementation process for the NAAQS, including the PM2.5 NAAQS. These discussions informed EPA about key Tribal concerns regarding designations as the rule was under development and gave Tribes the opportunity to express concerns about designations to EPA. Furthermore, EPA sent individualized letters to all federally recognized Tribes about EPA's intention to designate areas for the PM2.5 standard and gave Tribal leaders the opportunity for consultation.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045: ''Protection of Children From Environmental Health and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health and safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, EPA must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the EPA.

This final rule is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because EPA does not have reason to believe that the environmental health risks or safety risks addressed by this rule present a disproportionate risk or safety risk to children. Nonetheless, we have evaluated the environmental health or safety effects of the PM2.5 NAAQS on children. The results of this risk assessment are contained in the NAAQS for PM2.5, Final Rule (July 18, 1997, 62 FR 38652).

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211, ''Actions That Significantly Affect Energy Supply, Distribution, or Use,'' (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

Information on the methodology and data regarding the assessment of potential energy impacts is found in Chapter 6 of U.S. EPA 2002, Cost, Emission Reduction, Energy, and the Implementation Framework for the PM2.5 NAAQS, prepared by the Innovative Strategies and Economics Group, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 24, 2003.

I. National Technology Transfer Advancement Act (NTTAA)

Section 12(d) of the NTTAA of 1995, Public Law 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impracticable. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the EPA decides not to use available and applicable VCS.

This action does not involve technical standards. Therefore, EPA did not consider the use of any VCS.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). Pursuant to 5 U.S.C. 801, whether major or not, a rule generally cannot take effect until after submission of a rule report, including a copy of the rule, to each House of Congress and to the Comptroller General of the United States. A statutory exception to that requirement is provided in 5 U.S.C. 808(2), which provides that for a rule for which an agency for good cause finds ''that notice and public procedure thereon are impractical, unnecessary, or contrary to the public interest, [the rule] shall take effect at such time as the Federal agency promulgating the rule determines.'' The EPA finds that the criteria for the exception contained in 5 U.S.C. 808(2) are satisfied for the following reasons. Section 107(d)(2)(B) of the CAA explicitly exempts the designation process from compliance with the notice and comment procedures of the Administrative Procedures Act and EPA has concluded that it is appropriate to promulgate the designations following the specific procedures provided within section 107(d) of the CAA. Thus, EPA believes that additional notice and public procedure are unnecessary. Given the short time period between the submission by States of 2004 data and today's action, any such additional notice and public process would have been impracticable. Moreover, EPA has concluded that it is in the public interest to modify the designations of certain areas based upon inclusion of 2004 data in order to avoid the potential for delay and the waste of resources for such areas to pursue redesignation through other means. Therefore, EPA finds that notice and public comment procedures are unnecessary, impracticable, and contrary to the public interest for this rule. Thus, in accordance with 5 U.S.C. 808(2), EPA has concluded that today's rule can be effective on April 5, 2005. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**.

K. Judicial Review

Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by EPA. This section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit: (i) When EPA action consists of ''nationally applicable regulations promulgated, or final actions taken, by the Administrator,'' or (ii) when such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

This rule designating areas for the PM2.5 NAAQS is ''nationally applicable'' within the meaning of section 307(b)(1). This rule establishes designations for all areas of the United States for the PM2.5 NAAQS. At the core of this rulemaking is EPA's interpretation of the definition of nonattainment under section 107(d)(1) of the CAA. In determining which areas should be designated nonattainment (or conversely, should be designated attainment/unclassifiable), EPA used a set of nine technical factors that it applied consistently across the United States.

For the same reasons, the Administrator also is determining that the final designations are of nationwide scope and effect for the purposes of section 307(b)(1). This is particularly appropriate because in the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that an action is of ''nationwide scope or effect'' would be appropriate for any action that has ''scope or effect beyond a single judicial circuit.'' H.R. Rep. No. 95–294 at 323, 324, *reprinted* in 1977 U.S.C.C.A.N. 1402–03. Here, the scope and effect of this rulemaking extends to numerous judicial circuits since the designations apply to all areas of the

country. In these circumstances, section 307(b)(1) and its legislative history calls for the Administrator to find the rule to be of ''nationwide scope or effect'' and for venue to be in the D.C. Circuit.

Thus, any petitions for review of final designations must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

List of Subjects in 40 CFR Part 81

Environmental protection, Air pollution control, National parks, Wilderness areas.

Dated: April 5, 2005.

Stephen L. Johnson,

Acting Administrator.

■ For the reasons set forth in the preamble, 40 CFR part 81, subpart C is amended as follows:

PART 81—DESIGNATIONS OF AREAS FOR AIR QUALITY PLANNING PURPOSES

■ 1. The authority citation for part 81 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart C—Section 107 Attainment Status Designations

■ 2. In § 81.301, the ''Alabama—PM2.5'' table is amended by revising the entries for ''Columbus, GA-AL'',''DeKalb County, AL'' and ''Gadsen, AL'' to read as follows:

§ 81.301 Alabama.

* * * * *

ALABAMA—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * *	*	*
Columbus GA-AL:		
Russell County, AL	.....	Unclassifiable/Attainment.
* * * * *	*	*
DeKalb County, AL:		
DeKalb County	.....	Unclassifiable/Attainment.
* * * * *	*	*
Gadsden, AL:		
Etowah County	.....	Unclassifiable/Attainment.
* * * * *	*	*

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 3. In § 81.305, the ''California—PM2.5'' table is amended as follows:

■ a. Under ''Lake Tahoe Air Basin:'' by revising the entry for ''Placer County (part)''.

■ b. By revising the entry for ''Western Mojave Desert and Antelope Valley''.

■ c. By removing the entries for ''San Diego, CA:'' and ''San Diego County Tribal Area:''.

■ d. By adding a new entry for ''San Diego, CA'' at the end of table.

§ 81.305 California.

* * * * *

CALIFORNIA—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * *	*	*
Lake Tahoe Air Basin:		
* * * * *	*	*
Placer County (part):		
That portion of Placer County within the drainage area naturally tributary to Lake Tahoe including said Lake, plus that area in the vicinity of the head of the Truckee River described as follows: commencing at the point common to the aforementioned drainage area crestline and the line common to Townships 15 North and 16 North, Mount Diablo Base and Meridian, and following that line in a westerly direction to the northwest corner of Section 3, Township 15 North, Range 16 East, Mount Diablo Base and Meridian, thence south along the west line of Sections 3 and 10, Township 15 North, Range 16 East, Mount Diablo Base and Meridian, to the intersection with the said drainage area crestline, thence following the said drainage area boundary in a southeasterly, then northeasterly direction to and along the Lake Tahoe Dam, thence following the said drainage area crestline in a northeasterly, then northwesterly direction to the point of beginning.	.....	Unclassifiable/Attainment.
* * * * *	*	*
Western Mojave Desert and Antelope Valley:		

CALIFORNIA—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
Los Angeles County (part):		
That portion of Los Angeles County which lies north and east of a line described as follows: Beginning at the Los Angeles—San Bernardino County boundary and running west along the Township line common to Township 3 North and Township 2 North, San Bernardino Base and Meridian; then north along the range line common to Range 8 West and Range 9 West; then west along the Township line common to Township 4 North and Township 3 North; then north along the range line common to Range 12 West and Range 13 West to the southeast corner of Section 12, Township 5 North and Range 13 West; then west along the south boundaries of Sections 12, 11, 10, 9, 8, and 7, Township 5 North and Range 13 West to the boundary of the Angeles National Forest which is collinear with the range line common to Range 13 West and Range 14 West; then north and west along the Angeles National Forest boundary to the point of intersection with the Township line common to Township 7 North and Township 6 North (point is at the northwest corner of Section 4 in Township 6 North and Range 14 West); then west along the Township line common to Township 7 North and Township 6 North; then north along the range line common to Range 15 West and Range 16 West to the southeast corner of Section 13, Township 7 North and Range 16 West; then along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 7 North and Range 16 West; then north along the range line common to Range 16 West and Range 17 West to the north boundary of the Angeles National Forest (collinear with the Township line common to Township 8 North and Township 7 North); then west and north along the Angeles National Forest boundary to the point of intersection with the south boundary of the Rancho La Liebre Land Grant; then west and north along this land grant boundary to the Los Angeles-Kern County boundary.	.....	Unclassifiable/Attainment.
* * * * * * *		
San Diego, CA:		
San Diego County	.....	Unclassifiable/Attainment.
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 4. In § 81.311, the ''Georgia—PM2.5'' table is amended by revising the entry for ''Clarke County'' under the heading of ''Athens, GA,'', and by revising the entry for ''Muscogee'' under the heading ''Columbus GA–AL'' to read as follows:

§ 81.311 Georgia.

* * * * *

GEORGIA—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
Athens, GA:		
Clarke County	.....	Unclassifiable/Attainment.
Columbus, GA–AL:		
Muscogee County	.....	Unclassifiable/Attainment.
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 5. In § 81.314, the ''Illinois—PM2.5'' table is amended by revising the entry for ''Randolph County (part)'' under the heading of ''St. Louis, MO–IL'' to read as follows:

§ 81.314 Illinois.

* * * * *

ILLINOIS—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * * * *		
Randolph County (part)		
Baldwin Township	.....	Nonattainment.

ILLINOIS—PM2.5—Continued

Designated area	Designation [a]	
	Date [1]	Type
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 6. In § 81.315, the ''Indiana—PM2.5'' table is amended by revising the entry for ''Elkhart, IN'' and ''Muncie, IN'' to read as follows:

§ 81.315 Indiana.

* * * * *

INDIANA—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * * * *		
Elkhart, IN:		
Elkhart County		Unclassifiable/Attainment.
St. Joseph County		Unclassifiable/Attainment.
* * * * * * *		
Muncie, IN:		
Delaware County		Unclassifiable/Attainment.
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 7. In § 81.318, the ''Kentucky—PM2.5'' table is amended by revising the entry for ''Lexington, KY'' to read as follows:

§ 81.318 Kentucky.

* * * * *

KENTUCKY—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * * * *		
Lexington, KY:		
Fayette County		Unclassifiable/Attainment.
Mercer County (part),		Unclassifiable/Attainment
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 8. In § 81.319, the ''Louisiana—PM2.5'' table is revised to read as follows:

§ 81.319 Louisiana.

* * * * *

LOUISIANA—PM2.5

Designation area	Designated [a]	
	Date [1]	Type
AQCR 019 Monroe-El Dorado Interstate:		
Caldwell Parish		Unclassifiable/Attainment.
Catahoula Parish		Unclassifiable/Attainment.
Concordia Parish		Unclassifiable/Attainment.
East Carroll Parish		Unclassifiable/Attainment.
Franklin Parish		Unclassifiable/Attainment.
La Salle Parish		Unclassifiable/Attainment.

LOUISIANA—PM2.5—Continued

Designation area	Designated [a]	
	Date [1]	Type
Madison Parish		Unclassifiable/Attainment.
Morehouse Parish		Unclassifiable/Attainment.
Ouachita Parish		Unclassifiable/Attainment.
Richland Parish		Unclassifiable/Attainment.
Tensas Parish		Unclassifiable/Attainment.
Union Parish		Unclassifiable/Attainment.
West Carroll Parish		Unclassifiable/Attainment.
AQCR 022 Shreveport-Texarkana-Tyler Interstate:		
Bienville Parish		Unclassifiable/Attainment.
Bossier Parish		Unclassifiable/Attainment.
Caddo Parish		Unclassifiable/Attainment.
Claiborne Parish		Unclassifiable/Attainment.
De Soto Parish		Unclassifiable/Attainment.
Jackson Parish		Unclassifiable/Attainment.
Lincoln Parish		Unclassifiable/Attainment.
Natchitoches Parish		Unclassifiable/Attainment.
Red River Parish		Unclassifiable/Attainment.
Sabine Parish		Unclassifiable/Attainment.
Webster Parish		Unclassifiable/Attainment.
Winn Parish		Unclassifiable/Attainment.
AQCR 106 S. Louisiana-S.E. Texas Interstate:		
Acadia Parish		Unclassifiable/Attainment.
Allen Parish		Unclassifiable/Attainment.
Ascension Parish		Unclassifiable/Attainment.
Assumption Parish		Unclassifiable/Attainment.
Avoyelles Parish		Unclassifiable/Attainment.
Beauregard Parish		Unclassifiable/Attainment.
Calcasieu Parish		Unclassifiable/Attainment.
Cameron Parish		Unclassifiable/Attainment.
East Baton Rouge Parish		Unclassifiable/Attainment.
East Feliciana Parish		Unclassifiable/Attainment.
Evangeline Parish		Unclassifiable/Attainment.
Grant Parish		Unclassifiable/Attainment.
Iberia Parish		Unclassifiable/Attainment.
Iberville Parish		Unclassifiable/Attainment.
Jefferson Davis Parish		Unclassifiable/Attainment.
Jefferson Parish		Unclassifiable/Attainment.
Lafayette Parish		Unclassifiable/Attainment.
Lafourche Parish		Unclassifiable/Attainment.
Livingston Parish		Unclassifiable/Attainment.
Orleans Parish		Unclassifiable/Attainment.
Plaquemines Parish		Unclassifiable/Attainment.
Pointe Coupee Parish		Unclassifiable/Attainment.
Rapides Parish		Unclassifiable/Attainment.
St. Bernard Parish		Unclassifiable/Attainment.
St. Charles Parish		Unclassifiable/Attainment.
St. Helena Parish		Unclassifiable/Attainment.
St. James Parish		Unclassifiable/Attainment.
St. John the Baptist Parish		Unclassifiable/Attainment.
St. Landry Parish		Unclassifiable/Attainment.
St. Martin Parish		Unclassifiable/Attainment.
St. Tammany Parish		Unclassifiable/Attainment.
Tangipahoa Parish		Unclassifiable/Attainment.
Terrebonne Parish		Unclassifiable/Attainment.
Vermilion Parish		Unclassifiable/Attainment.
Vernon Parish		Unclassifiable/Attainment.
Washington Parish		Unclassifiable/Attainment.
West Baton Rouge Parish		Unclassifiable/Attainment.
West Feliciana Parish		Unclassifiable/Attainment.

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 9. In § 81.336, the ''Ohio—PM2.5'' table is amended by revising the entries for Gallia County under the heading of ''Huntington-Ashland, WV-KY-OH'', for ''Toledo, OH'', and for ''Youngstown-Warren-Sharon, OH-PA'' to read as follows:

§ 81.336 Ohio.

* * * * *

OHIO—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * * * *		
Gallia County (part)		
Cheshire Township		Nonattainment.
* * * * * * *		
Toledo, OH:		
Lucas County		Unclassifiable/Attainment.
Wood County		Unclassifiable/Attainment.
* * * * * * *		
Youngstown-Warren-Sharon, OH-PA:		
Columbiana County		Unclassifiable/Attainment.
Mahoning County		Unclassifiable/Attainment.
Trumbull County		Unclassifiable/Attainment.
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

* * * * *

■ 10. In § 81.339, the ''Pennsylvania—PM2.5'' table is amended by revising the entry for ''Youngstown-Warren-Sharon, OH-PA'' to read as follows:

§ 81.339 Pennsylvania.

PENNSYLVANIA—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * * *		
Youngstown-Warren-Sharon, OH-PA:		
Mercer County		Unclassifiable/Attainment.
* * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 11. In § 81.343, the ''Tennessee—PM2.5'' table is amended by revising the entry for ''McMinn County, TN'' to read as follows:

§ 81.343 Tennessee.

* * * * *

TENNESSEE—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * * * *		
McMinn County, TN:		
McMinn County		Unclassifiable/Attainment.
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

■ 12. In § 81.349, the ''West Virginia—PM2.5'' table is amended by revising the entry for ''Marion County, WV (aka Fairmont CBSA)'' to read as follows:

§ 81.349 West Virginia.

* * * * *

WEST VIRGINIA—PM2.5

Designated area	Designation [a]	
	Date [1]	Type
* * * * * * *		
Marion County, WV (aka Fairmont CBSA):		
Harrison County (part).		
Tax District of Clay		Unclassifiable/Attainment.
Marion County		Unclassifiable/Attainment.
Monongalia County.		
Tax District of Cass		Unclassifiable/Attainment.
* * * * * * *		

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is 90 days after January 5, 2005, unless otherwise noted.

[FR Doc. 05–7227 Filed 4–13–05; 8:45 am]
BILLING CODE 6560–50–P

Federal Register

Wednesday,
April 25, 2007

Part II

Environmental Protection Agency

40 CFR Part 51

Clean Air Fine Particle Implementation Rule; Final Rule

Agency Information Collection Activities: Proposed Collection; Comment Request; $PM_{2.5}$ Ozone National Ambient Air Quality Standard Implementation Rule; EPA ICR No. 2258.01; Notice

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[EPA–HQ–OAR–2003–0062; FRL–8295–2]

RIN 2060–AK74

Clean Air Fine Particle Implementation Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This final action provides rules and guidance on the Clean Air Act (CAA) requirements for State and Tribal plans to implement the 1997 fine particle ($PM_{2.5}$) national ambient air quality standards (NAAQS). Fine particles and precursor pollutants are emitted by a wide range of sources, including power plants, cars, trucks, industrial sources, and other burning or combustion-related activities. Health effects that have been associated with exposure to $PM_{2.5}$ include premature death, aggravation of heart and lung disease, and asthma attacks. Those particularly sensitive to $PM_{2.5}$ exposure include older adults, people with heart and lung disease, and children.

Air quality designations became effective on April 5, 2005 for 39 areas (with a total population of 90 million) that were not attaining the 1997 $PM_{2.5}$ standards. By April 5, 2008, each State having a nonattainment area must submit to EPA an attainment demonstration and adopted regulations ensuring that the area will attain the standards as expeditiously as practicable, but no later than 2015. This rule and preamble describe the requirements that States and Tribes must meet in their implementation plans for attainment of the 1997 fine particle NAAQS. (Note that this rule does not include final $PM_{2.5}$ requirements for the new source review (NSR) program; the final NSR rule will be issued at a later date.)

DATES: This rule is effective on May 29, 2007.

ADDRESSES: The EPA has established a docket for this action under Docket ID EPA–HQ–OAR–2003–0062. All documents relevant to this action are listed in the Federal docket management system at *www.regulations.gov*. Although listed in the index, some information is not publicly available (e.g. Confidential Business Information or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through www.regulations.gov or in hard copy format at the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Office of Air and Radiation Docket and Information Center is (202) 566–1742. A variety of information and materials related to the fine particle NAAQS and implementation program are also available on EPA's Web site: *http://www.epa.gov/air/particles*.

FOR FURTHER INFORMATION CONTACT: For general information, contact Mr. Richard Damberg, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Mail Code C539–01, Research Triangle Park, NC 27711, phone number (919) 54l–5592 or by e-mail at: *damberg.rich@epa.gov*.

SUPPLEMENTARY INFORMATION:

General Information

A. Does this action apply to me?

Entities potentially regulated by this action are State and local air quality agencies.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final rule will also be available on the World Wide Web. Following signature by the EPA Administrator, a copy of this final rule will be posted at *http://www.epa.gov/particles/actions.html*.

C. How is the preamble organized?

I. Background

Fine particles in the atmosphere are comprised of a complex mixture of components. Common constituents include: sulfate (SO_4); nitrate (NO_3); ammonium; elemental carbon; a great variety of organic compounds; and inorganic material (including metals, dust, sea salt, and other trace elements) generally referred to as ''crustal'' material, although it may contain material from other sources. Airborne particles generally less than or equal to 2.5 micrometers in diameter are considered to be ''fine particles'' (also referred to as $PM_{2.5}$). (A micrometer is one-millionth of a meter, and 2.5 micrometers is less than one-seventh the average width of a human hair.) ''Primary'' particles are emitted directly into the air as a solid or liquid particle (e.g., elemental carbon from diesel engines or fire activities, or condensable organic particles from gasoline engines). ''Secondary'' particles (e.g., sulfate and nitrate) form in the atmosphere as a result of various chemical reactions. (Section II of the proposed rule included detailed technical discussion on $PM_{2.5}$, its precursors, formation processes, and emissions sources.)

The EPA established air quality standards for $PM_{2.5}$ based on evidence from numerous health studies demonstrating that serious health effects are associated with exposures to elevated levels of $PM_{2.5}$. Epidemiological studies have shown statistically significant correlations between elevated $PM_{2.5}$ levels and premature mortality. Other important

effects associated with $PM_{2.5}$ exposure include aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, absences from school or work, and restricted activity days), changes in lung function and increased respiratory symptoms, as well as new evidence for more subtle indicators of cardiovascular health. Individuals particularly sensitive to $PM_{2.5}$ exposure include older adults, people with heart and lung disease, and children.

On July 18, 1997, we revised the NAAQS for particulate matter (PM) to add new standards for fine particles, using $PM_{2.5}$ as the indicator. We established health-based (primary) annual and 24-hour standards for $PM_{2.5}$ (62 FR 38652).[1] The annual standard was set at a level of 15 micrograms per cubic meter, as determined by the 3-year average of annual mean $PM_{2.5}$ concentrations. The 24-hour standard was set at a level of 65 micrograms per cubic meter, as determined by the 3-year average of the 98th percentile of 24-hour concentrations.

Attainment of the 1997 $PM_{2.5}$ standards is estimated to lead to reductions in health impacts, including tens of thousands fewer premature deaths each year, thousands fewer hospital admissions and emergency room visits each year, hundreds of thousands fewer absences from work and school, and hundreds of thousands fewer respiratory illnesses in children annually. The EPA's evaluation of the science concluded that there was not sufficient information to either support or refute the existence of a threshold for health effects from PM exposure.[2]

We subsequently completed in October 2006 another review of the NAAQS for PM. With regard to the primary standards, the 24-hour $PM_{2.5}$ standard was strengthened to a level of 35 micrograms per cubic meter, based on the 3-year average of the 98th percentile of 24-hour concentrations, and the level of the annual standard remained unchanged.[3] Attainment of the 2006 $PM_{2.5}$ standards is estimated to lead to additional reductions in health impacts, including approximately 1,200 to 13,000 fewer premature deaths each year, 1,630 fewer hospital admissions and 1,200 fewer emergency room visits for asthma each year, 350,000 fewer absences from work and school, and 155,300 fewer respiratory illnesses in children annually.[4]

In both 1997 and 2006 EPA established welfare-based (secondary) standards identical to the levels of the primary standards. The secondary standards are designed to protect against major environmental effects of $PM_{2.5}$ such as visibility impairment, soiling, and materials damage. The EPA also established the regional haze regulations in 1999 for the improvement of visual air quality in national parks and wilderness areas across the country. Because regional haze is caused primarily by light scattering and light absorption by fine particles in the atmosphere, EPA is encouraging the States to integrate their efforts to attain the $PM_{2.5}$ standards with those efforts to establish reasonable progress goals and associated emission reduction strategies for the purposes of improving air quality in our treasured natural areas under the regional haze program.

The scientific assessments used in the development of the $PM_{2.5}$ standards included a scientific peer review and public comment process. We developed scientific background documents based on the review of hundreds of peer-reviewed scientific studies. The Clean Air Scientific Advisory Committee, a congressionally mandated group of independent scientific and technical experts, provided extensive review of these assessments, and found that EPA's review of the science provided an adequate basis for the EPA Administrator to make a decision. More detailed information on health effects of $PM_{2.5}$ can be found on EPA's Web site at: *http://www.epa.gov/air/urbanair/pm/index.html*. Additional information on EPA's scientific assessment documents supporting the 1997 standards are available at *http://www.epa.gov/ttn/oarpg/t1cd.html*; additional scientific assessment information on the 2006 standards is available at: *http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_cr_cd.html.*

The EPA issued final $PM_{2.5}$ designations for areas violating the 1997 standards on December 17, 2004. They were published in the **Federal Register** on January 5, 2005 (70 FR 944). On April 5, 2005, EPA issued a supplemental notice which changed the designation status of eight areas from nonattainment to attainment based on newly updated 2002–2004 air quality data (70 FR 19844; published in the **Federal Register** on April 14, 2005). A total of 39 areas were designated as nonattainment for the 1997 $PM_{2.5}$ standards. The population of these areas is estimated at about 90 million (or more than 30% of the U.S. population). Most of these areas only violate the annual standard, but a few violate both the annual and 24-hour standards.

The nonattainment designation for an area starts the process whereby a State or Tribe must develop an implementation plan that includes, among other things, a demonstration showing how it will attain the ambient standards by the attainment dates required in the CAA. Under section 172(b), States have up to 3 years after EPA's final designations to submit their SIPs to EPA. These SIPs will be due on April 5, 2008, 3 years from the effective date of the designations.

Section 172(a)(2) of the Act requires States to attain the standards as expeditiously as practicable but within 5 years of designation (i.e. attainment date of April 2010 based on air quality data for 2007–2009), or within up to 10 years of designation (i.e. to April 2015) if the EPA Administrator extends an area's attainment date by 1–5 years based upon the severity of the nonattainment problem or the feasibility of implementing control measures.

Virtually all nonattainment problems appear to result from a combination of local emissions and transported emissions from upwind areas. The structure of the CAA requires EPA to develop national rules for certain types of sources which are also significant contributors to local air quality problems, including motor vehicles and fuels. It also provides for States to address emissions sources on an area-specific basis through such requirements as RACT, RACM, and RFP.

We believe that to attain the $PM_{2.5}$ standards, it is important to pursue emissions reductions simultaneously on the local, regional, and national levels. The EPA issued the Clean Air Interstate

[1] The original annual and daily standards for particles generally less than or equal to 10 micrometers in diameter (also referred to as PM_{10}) were established in 1987. In the 1997 PM NAAQS revision, EPA also revised the standards for PM_{10}, but these revised PM_{10} standards were later vacated by the court, and the 1987 PM_{10} standards remained in effect. In the 2006 NAAQS revision, the 24-hour PM_{10} standard was retained but the annual standard was revoked. Today's implementation rule and guidance does not address PM_{10}.

[2] Environmental Protection Agency. (2004a). Air Quality Criteria for Particulate Matter. Research Triangle Park, NC: National Center for Environmental Assessment—RTP, Office of Research and Development, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; report no. EPA/600/P–99/002aF and EPA/600/P–99/002bF. October 2004.

[3] The revised fine particle NAAQS were published on October 17, 2006 (71 FR 61144). See EPA's Web site for additional information: *http://www.epa.gov/pm/index.html.*

[4] Regulatory Impact Analysis for Particulate Matter National Ambient Air Quality Standards (September 2006), page ES–8. The mortality range includes estimates based on the results of an expert elicitation study, along with published epidemiological studies.

Rule (CAIR)[5] on March 10, 2005 to address the interstate transport of sulfur dioxide and nitrogen oxide emissions primarily from power plants. Section 110 gives EPA the authority to require SIPs to ''prohibit * * * any source or other type of emission activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to'' any NAAQS, and to prohibit sources or emission activities from emitting pollutants in amounts which will interfere with measures required to be included in State plans to prevent significant deterioration of air quality or to protect visibility (such as the protection of 156 mandatory Federal class I areas under the regional haze rule[6]). CAIR employs the same emissions trading approach used to achieve cost-effective emission reductions under the acid rain program. It outlines a two-phase program with increasingly tighter power plant emissions caps for 28 eastern states and the District of Columbia: SO_2 caps of 3.6 million tons in 2010, and 2.5 million in 2015; NO_X caps of 1.5 in 2009 and 1.3 in 2015; and NO_X ozone season caps of 580,000 tons in 2009 and 480,000 tons in 2015. Emission caps are divided into State SO_2 and NO_X budgets. By the year 2015, the Clean Air Interstate Rule is estimated to result in:

—$85 to $100 billion in annual health benefits, including preventing 17,000 premature deaths, millions of lost work and school days, and tens of thousands of non-fatal heart attacks and hospital admissions annually.
—Nearly $2 billion in annual visibility benefits in southeastern national parks, such as Great Smoky and Shenandoah.
—Significant regional reductions in sulfur and nitrogen deposition, reducing the number of acidic lakes and streams in the eastern U.S.

Over the past several years, EPA has also issued a number of regulations addressing emissions standards for new cars, trucks and buses. These standards are providing reductions in motor vehicle emissions of volatile organic compounds (VOCs, also referred to as hydrocarbons), NO_X, and direct PM emissions (such as elemental carbon) as older vehicles are retired and replaced. Other existing rules are designed to reduce emissions from several categories of nonroad engines. The Tier 2 motor vehicle emission standards, together with the associated requirements to reduce sulfur in gasoline, are estimated to provide additional benefits nationally beginning in 2004.[7] When the new tailpipe and sulfur standards are fully implemented, Americans are estimated to benefit from the clean-air equivalent of removing 164 million cars from the road. These new standards require passenger vehicles to have emissions 77 to 95 percent cleaner than those on the road today and require fuel manufacturers to reduce the sulfur content of gasoline by up to 90 percent. In addition, the 2001 heavy-duty diesel engine regulations[8] will lead to continued emissions reductions as older vehicles in that engine class are retired and fleets turn over. New emission standards began to take effect for model year 2007 and apply to heavy-duty highway engines and vehicles. These standards are based on the use of high-efficiency catalytic exhaust emission control devices or comparably effective advanced technologies. Because these devices are damaged by sulfur, the level of sulfur in highway diesel fuel was to be reduced by 97 percent by mid-2006. We project a 2.6 million ton reduction of NO_X emissions in 2030 when the current heavy-duty vehicle fleet is completely replaced with newer heavy-duty vehicles that comply with these emission standards. By 2030, we estimate that this program will reduce annual emissions of hydrocarbons by 115,000 tons and PM by 109,000 tons. These emissions reductions are on par with those that we anticipate from new passenger vehicles and low sulfur gasoline under the Tier 2 program.

The EPA also finalized national rules in May 2004 to reduce significantly $PM_{2.5}$ and NO_X emissions from nonroad diesel-powered equipment.[9] These nonroad sources include construction, agricultural, and industrial equipment, and their emissions constitute an important fraction of the inventory for direct $PM_{2.5}$ emissions (such as elemental carbon and organic carbon), and NO_X. The EPA estimates that affected nonroad diesel engines currently account for about 44 percent of total diesel PM emissions and about 12 percent of total NO_X emissions from mobile sources nationwide. These proportions are even higher in some urban areas. The diesel emission standards will reduce emissions from this category by more than 90 percent, and are similar to the onroad engine requirements implemented for highway trucks and buses. Because the emission control devices can be damaged by sulfur, EPA also established requirements to reduce the allowable level of sulfur in nonroad diesel fuel by more than 99 percent by 2010. In 2030, when the full inventory of older nonroad engines has been replaced, the nonroad diesel program will annually prevent up to 12,000 premature deaths, one million lost work days, 15,000 heart attacks and 6,000 children's asthma-related emergency room visits.

The EPA expects the implementation of regional and national emission reduction programs such as CAIR and the suite of mobile source rules described above to provide significant air quality improvements for $PM_{2.5}$ nonattainment areas. At the same time, analyses for the final CAIR rule indicate that without implementation of local measures, a number of $PM_{2.5}$ areas are projected to remain in nonattainment status in the 2010–2015 timeframe. Thus, EPA believes that local and State emission reduction efforts will need to play an important role in addressing the $PM_{2.5}$ problem as well. The EPA will work closely with States, Tribes, and local governments to develop appropriate in-state pollution reduction measures to complement regional and national strategies to meet the standards expeditiously and in a cost-effective manner. States will need to evaluate technically and economically feasible emission reduction opportunities and determine which measures can be reasonably implemented in the near term. Local and regional emission reduction efforts should proceed concurrently and expeditiously.

The promulgation of a revised 24-hour $PM_{2.5}$ standard effective on December 18, 2006 has initiated another process of State recommendations, and the eventual designation by EPA of areas not attaining the revised standard. The additional designations are to be completed within two years from the effective date, although EPA may take an additional year to complete the designations if it determines it does not have sufficient information. State plans to attain the 24-hour standard would then be due within three years of the final designations. A number of areas, including some that are already designated as not attaining the 1997 standards, may be exceeding the revised 24-hour standard. The EPA encourages State and local governments to be mindful of the strengthened 24-hour standard as they adopt emission reduction strategies to attain the 1997 standards. Such steps may help with

[5] See *http://www.epa.gov/cair.*

[6] See 64 FR 35714, July 1, 1999.

[7] See Tier II emission standards at 65 FR 6698, February 10, 2000.

[8] See heavy-duty diesel engine regulations at 66 FR 5002, January 18, 2001.

[9] For more information on the proposed nonroad diesel engine standards, see EPA's Web site: *http://www.epa.gov/nonroad/.*

future attainment efforts, or even help some areas avoid a nonattainment designation for the 24-hour standard in the first place.

The public health benefits of meeting the $PM_{2.5}$ standards are estimated to be significant. Even small reductions in $PM_{2.5}$ levels may have substantial health benefits on a population level. For example, in a moderate-sized metropolitan area with a design value of 15.5 µg/m3, efforts to improve annual average air quality down to the level of the standard (15.0 µg/m3) are estimated to result in as many as 25–50 fewer mortalities per year due to air pollution exposure. In a smaller city, the same air quality improvement from 15.5 to 15.0 µg/m3 still are estimated to result in a number of avoided mortalities per year. These estimates are based on EPA's standard methodology for calculating health benefits as used in recent rulemakings.[10] In addition, because many different precursors contribute to the formation of fine particles, reductions in pollutants that contribute to $PM_{2.5}$ also can provide concurrent benefits in addressing a number of other air quality problems—such as ground-level ozone, regional haze, toxic air pollutants, and urban visibility impairment.

In order to assist States in developing effective plans to address the local component of the $PM_{2.5}$ nonattainment problem, EPA is issuing this final fine particle implementation rule. The EPA is issuing this rule to implement the 1997 $PM_{2.5}$ NAAQS in accordance with the statutory requirements of the CAA set forth in Subpart 1 of Part D of Title 1, *i.e.*, sections 171–179B of the Act. The EPA believes that the CAA directs the Agency to implement new or revised NAAQS in nonattainment areas solely in accordance with Subpart 1, unless another Subpart of the Act also applies to the particular NAAQS at issue. In this case, EPA has concluded that Congress did not intend the Agency to implement particulate matter NAAQS other than those using PM_{10} as the indicator in accordance with Subpart 4 of Part D of Title 1, *i.e.*, sections 188–190 of the CAA. Moreover, EPA believes that implementation of the $PM_{2.5}$ NAAQS under the provisions of Subpart 1 is more appropriate, given the inherent nature of the $PM_{2.5}$ nonattainment problem. In contrast to PM_{10}, EPA anticipates that achieving the NAAQS for $PM_{2.5}$ will generally require States to evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control strategies. As a result, EPA has concluded that the provisions of Subpart 1 will allow States and EPA to tailor attainment plans so that they can be based more specifically upon the facts and circumstances of each nonattainment area.

The proposed clean air fine particle implementation rule was issued on November 1, 2005 (70 FR 65984). About 100 comments were received from private citizens and parties representing industry, state and local governments, environmental groups, and federal agencies. Section II of this document describes the primary elements of the fine particle implementation program. Each section summarizes the relevant policies and options discussed in the proposed rule, discusses the final policy set forth by EPA in the final rule, and provides responses to the major comments received on each issue.

II. Elements of the Clean Air Fine Particle Implementation Rule

A. Precursors and Pollutants Contributing to Fine Particle Formation

1. Introduction

The main precursor gases associated with fine particle formation are SO_2, NO_X, volatile organic compounds (VOC), and ammonia. This section provides technical background on each precursor, discusses the policy approach for addressing each precursor under the $PM_{2.5}$ implementation program, and responds to key issues raised in the public comment process. A subsection is also included on direct $PM_{2.5}$ emissions to address key comments received on this issue as well.

Gas-phase precursors SO_2, NO_X, VOC, and ammonia undergo chemical reactions in the atmosphere to form secondary particulate matter. Formation of secondary PM depends on numerous factors including the concentrations of precursors; the concentrations of other gaseous reactive species; atmospheric conditions including solar radiation, temperature, and relative humidity (RH); and the interactions of precursors with preexisting particles and with cloud or fog droplets. Several atmospheric aerosol species, such as ammonium nitrate and certain organic compounds, are semivolatile and are found in both gas and particle phases. Given the complexity of PM formation processes, new information from the scientific community continues to emerge to improve our understanding of the relationship between sources of PM precursors and secondary particle formation.

As an initial matter, it is helpful to clarify the terminology we use throughout this notice to discuss precursors. We recognize NO_X, SO_2, VOCs, and ammonia as precursors of $PM_{2.5}$ in the scientific sense because these pollutants can contribute to the formation of $PM_{2.5}$ in the ambient air. In section II.K on emission inventory issues, we make the point that because of the complex and variable interaction of multiple pollutants and precursors in the formation of fine particles, it is important for States and EPA to continue to characterize and improve the emissions inventories for all $PM_{2.5}$ precursors. The States and EPA need to use the best available information available in conducting air quality modeling and other assessments. At the same time, the refinement of emissions inventories, the overall contribution of different fine particle precursors to $PM_{2.5}$ formation, and the efficacy of alternative potential control measures will vary by location. This requires that we further consider in this action how States should address these $PM_{2.5}$ precursors in their $PM_{2.5}$ attainment plan programs. Thus, we require emission inventories to include the best available information on all pollutants and precursors that contribute to $PM_{2.5}$ concentrations, and at same time we use the term ''$PM_{2.5}$ attainment plan precursor'' to describe only those precursors that are required to be evaluated for control strategies in a specific $PM_{2.5}$ nonattainment area or maintenance area plan.

In this rule, EPA has not made a finding that all precursors should be evaluated for possible controls in each specific nonattainment area. The policy approach in the rule instead requires sulfur dioxide to be evaluated for control measures in all areas, and describes general presumptive policies for NO_X, ammonia, and VOC for all nonattainment areas. The rule provides a mechanism by which the State and/or EPA can make an area-specific demonstration to reverse the general presumption for these three precursors. States must also consider any relevant information brought forward by interested parties in the SIP planning and development process. (See section II.A.8 for additional discussion on these issues.)

In the following sections, we discuss how States must evaluate $PM_{2.5}$ precursors for nonattainment program issues in $PM_{2.5}$ implementation plans,

[10] See: U.S. EPA 2006. Regulatory Impact Analysis for the Particulate Matter National Ambient Air Quality Standards. Air Benefits and Cost Group, Office of Air Quality Planning and Standards, Research Triangle Park, N.C. October 6, 2006. Appendix A provides an analysis of estimated benefits and costs of attaining the 1997 PM NAAQS standards in 2015.

including issues such as RACT, RACM, and reasonable further progress. This discussion in the final rule is linked to precursor policies for the implementation of the new source review program, the transportation conformity program, the general conformity program, and the regional haze program. All of these programs take effect prior to approval of SIPs for attaining the $PM_{2.5}$ NAAQS. In the case of NSR, the program applies on the effective date of the nonattainment area designation. In the case of transportation conformity and general conformity, the program takes effect 1 year from the effective date of designation of the nonattainment area (i.e., April 5, 2006 for areas designated nonattainment effective April 5, 2005). Thus, for each of these programs there is an interim period between the date the program becomes applicable to a given nonattainment area and the date the State receives EPA approval of its overall $PM_{2.5}$ implementation plan.

2. Legal Authority to Regulate Precursors

a. Background

The CAA authorizes the Agency to regulate criteria pollutant precursors. The term ''air pollutant'' is defined in section 302(g) to include ''any precursors to the formation of any air pollutant, to the extent the Administrator has identified such precursor or precursors for the particular purpose for which the term 'air pollutant' is used.'' The first clause of this second sentence in section 302(g) explicitly authorizes the Administrator to identify and regulate precursors as air pollutants under other parts of the CAA. In addition, the second clause of the sentence indicates that the Administrator has discretion to identify which pollutants should be classified as precursors for particular regulatory purposes. Thus, we do not necessarily construe the CAA to require that EPA identify a particular precursor as an air pollutant for all regulatory purposes where it can be demonstrated that various CAA programs address different aspects of the air pollutant problem. Likewise, we do not interpret the CAA to require that EPA treat all precursors of a particular pollutant the same under any one program when there is a basis to distinguish between such precursors. For example, in a rule addressing $PM_{2.5}$ precursors for purposes of the transportation conformity program, we chose to adopt a different approach for one precursor based on the limited emissions of that precursor from onroad mobile sources and the degree to which it contributes to $PM_{2.5}$ concentrations. (70 FR 24280; May 6, 2005).

Other provisions of the CAA reinforce our reading of section 302(g) that Congress intended precursors to NAAQS pollutants to be subject to the air quality planning and control requirements of the CAA, but also recognized that there may be circumstances where it is not appropriate to subject precursors to certain requirements of the CAA. Section 182 of the CAA provides for the regulation of NO_X and VOCs as precursors to ozone in ozone nonattainment areas, but also provides in section 182(f) that major stationary sources of NO_X (an ozone precursor) are not subject to emission reductions controls for ozone where the State shows through modeling that NO_X reductions do not decrease ozone. Section 189(e) provides for the regulation of PM_{10} precursors in PM_{10} nonattainment areas, but also recognizes that there may be certain circumstances (e.g. if precursor emission sources do not significantly contribute to PM_{10} levels) where it is not appropriate to apply control requirements to PM_{10} precursors. The legislative history of Section 189(e) recognized the complexity behind the science of precursor transformation into PM_{10} ambient concentrations and the need to harmonize the regulation of PM_{10} precursors with other provisions of the CAA:

> The Committee notes that some of these precursors may well be controlled under other provisions of the CAA. The Committee intends that * * * the Administrator will develop models, mechanisms, and other methodology to assess the significance of the PM_{10} precursors in improving air quality and reducing PM_{10}. Additionally, the Administrator should consider the impact on ozone levels of PM_{10} precursor controls. The Committee expects the Administrator to harmonize the PM_{10} reduction objective of this section with other applicable regulations of this CAA regarding PM_{10} precursors, such as NO_X. See H. Rpt. 101–490, Pt. 1, at 268 (May 17, 1990), reprinted in S. Prt. 103–38, Vol. II, at 3292.

In summary, section 302(g) of the CAA clearly calls for the regulation of precursor pollutants, but the CAA also identifies circumstances when it may not be appropriate to regulate precursors and gives the Administrator discretion to determine how to address particular precursors under various programs required by the CAA. Due to the complexities associated with precursor emissions and their variability from location to location, we believe that in certain situations it may not be effective or appropriate to control a certain precursor under a particular regulatory program or for EPA to require similar control of a particular precursor in all areas of the country.

b. Final Rule

The final rule maintains the same legal basis for regulating precursors as was described in the proposal and in the background section above. We also include a clarification of the term ''significant contributor.''

In the proposal, when considering the impacts of the precursors NO_X, VOC and ammonia on ambient concentrations of particulate matter, we referred to the possibility of reversing the presumed approach for regulating or not regulating a precursor if it can be shown that the precursor in question is or is not a ''significant contributor'' to $PM_{2.5}$ concentrations within the specific nonattainment area. ''Significant contribution'' in this context is a different concept than that in Section 110(a)(2)(D). Section 110(a)(2)(D) prohibits States from emitting air pollutants in amounts which significantly contribute to nonattainment or other air quality problems in other states. Consistent with the discussion of sections 189(e) and 302(g) above, we are clarifying that the use in this implementation rule of the term ''significant contribution'' to the nonattainment area's $PM_{2.5}$ concentration means that a significant change in emissions of the precursor from sources in the state would be projected to provide a significant change in $PM_{2.5}$ concentrations in the nonattainment area. For example, if modeling indicates that a reduction in a state's NO_X emissions would reduce ambient $PM_{2.5}$ levels in the nonattainment area, but that a reduction in ammonia emissions would result in virtually no change in ambient $PM_{2.5}$ levels, this would suggest that NO_X is a significant contributor but that ammonia is not. The EPA in this rule is not establishing a quantitative test for determining whether $PM_{2.5}$ levels in a nonattainment area change significantly in response to reductions in precursor emissions in a state. However, in considering this question, it is relevant to consider that relatively small reductions in $PM_{2.5}$ levels are estimated to result in worthwhile public health benefits.

This approach to identifying a precursor for regulation reflects atmospheric chemistry conditions in the area and the magnitude of emissions of the precursor in the area or State. Assessments of which source categories are more cost effective or technically feasible to control should be part of the later RACT and RACM assessment, to

occur after the basic assessment of which precursors are to be regulated is completed.

In the proposed regulatory text, the provisions for reversing presumptions for NO_X, VOC and ammonia included consideration of whether the precursor would significantly contribute to ''other downwind air quality concerns.'' In the final rule we have removed that language to clarify that identification of attainment plan precursors involves evaluation of the impact on $PM_{2.5}$ levels in a nonattainment area of precursor emissions from sources within the state(s) where the nonattainment area is located. Other parts of the Act, notably section 110(a)(2)(D) and section 126, focus on interstate transport of pollutants.

c. Comments and Responses

Comment: The EPA received several comments supporting EPA's interpretation of 302(g) to determine the appropriate regulatory status of each precursor pollutant.

Response: The EPA agrees with the commenters. In establishing section 302(g), Congress intended that precursors to NAAQS pollutants be subject to the air quality planning and control requirements of the CAA. However, the CAA also recognizes that there may be circumstances where it is not appropriate to subject precursors to certain requirements of the CAA.

Comment: The EPA received several comments regarding the applicability of section 189(e), noting that it requires states to presumptively control sources of PM_{10} precursors except where the EPA ''determines that such sources [of precursors] do not significantly contribute to PM_{10} levels which exceed the standard in the area.'' Several commenters stated that EPA does not have the legal authority to regulate $PM_{2.5}$ precursors in a different manner. Several commenters maintained that all $PM_{2.5}$ precursors presumptively should be subject to regulation unless demonstrated by the State as not a significant contributor to $PM_{2.5}$ concentrations in a specific area.

Response: As stated above, EPA believes that section 302(g) allows the Administrator to presumptively not require certain precursors to be addressed in $PM_{2.5}$ implementation plans generally, while allowing the State or EPA to make a finding for a specific area to override the general presumption. In the following pollutant-specific sections of this preamble, EPA finds that at this time there is sufficient uncertainty regarding whether certain precursors significantly contribute to $PM_{2.5}$ concentrations in all nonattainment areas such that the policy set forth in this rule does not presumptively require certain precursors (ammonia, VOC) to be controlled in each area. However, the State or EPA may reverse the presumption and regulate a precursor if it provides a demonstration showing that the precursor is a significant contributor to $PM_{2.5}$ concentrations in the area. In addition, if in the State's SIP planning and adoption process a commenter provides additional information suggesting an alternative policy for regulating a particular precursor, the State will need to respond to this information in its rulemaking action.

3. Policy for Ammonia

[Section II.E.2 of November 1, 2005 proposed rule (70 FR 65999); sec. 51.1002 in draft and final regulatory text.]

a. Background

Ammonia (NH_3) is a gaseous pollutant that is emitted by natural and anthropogenic sources. Emissions inventories for ammonia are considered to be among the most uncertain of any species related to PM. Ammonia serves an important role in neutralizing acids in clouds, precipitation and particles. In particular, ammonia neutralizes sulfuric acid and nitric acid, the two key contributors to acid deposition (acid rain). Deposited ammonia also can contribute to problems of eutrophication in water bodies, and deposition of ammonium particles may effectively result in acidification of soil as ammonia is taken up by plants. The NARSTO Fine Particle Assessment [11] indicates that reducing ammonia emissions where sulfate concentrations are high may reduce $PM_{2.5}$ mass concentrations, but may also increase the acidity of particles and precipitation. An increase in particle acidity is suspected to be linked with human health effects and with an increase in the formation of secondary organic compounds. Based on the above information and further insights gained from the NARSTO Fine Particle Assessment, it is apparent that the formation of particles related to ammonia emissions is a complex, nonlinear process.

Though recent studies have improved our understanding of the role of ammonia in aerosol formation, ongoing research is required to better describe the relationships between ammonia emissions, particulate matter concentrations, and related impacts. The control techniques for ammonia and the analytical tools to quantify the impacts of reducing ammonia emissions on atmospheric aerosol formation are both evolving. Also, area-specific data are needed to evaluate the effectiveness of reducing ammonia emissions on reducing $PM_{2.5}$ concentrations in different areas, and to determine where ammonia decreases may increase the acidity of particles and precipitation.

The proposal showed consideration for the uncertainties about ammonia emissions inventories and about the potential efficacy of ammonia control measures by providing for a case-by-case approach. It was recommended that each State should evaluate whether reducing ammonia emissions would lead to $PM_{2.5}$ reductions in their specific $PM_{2.5}$ nonattainment areas. The proposed policy did not require States to address ammonia as a $PM_{2.5}$ attainment plan precursor, unless a technical demonstration by the State or EPA showed that ammonia emissions from sources in the State significantly contribute to $PM_{2.5}$ concentrations in a given nonattainment area or to other downwind air quality concerns. Where the State or EPA has determined that ammonia is a significant contributor to $PM_{2.5}$ formation in a nonattainment area, the State would be required to evaluate control measures for ammonia emissions in its nonattainment SIP due in 2008, in the implementation of the PM program, and in other associated programs in that area.

b. Final Rule

In the final rule, ammonia is presumed not to be a $PM_{2.5}$ attainment plan precursor, meaning that the State is not required to address ammonia in its attainment plan or evaluate sources of ammonia emissions for reduction measures. This presumption can be reversed based on an acceptable technical demonstration for a particular area by the State or EPA. If a technical demonstration by the State or EPA shows that ammonia emissions from sources in the State significantly contribute to $PM_{2.5}$ concentrations in a given nonattainment area, the State must then evaluate and consider control strategies for reducing ammonia emissions in its nonattainment SIP due in 2008, in the implementation of the $PM_{2.5}$ program. Technical demonstrations on ammonia should also consider the potential for atmospheric and particle acidity to increase with ammonia reductions. Further discussion about technical demonstrations to

[11] NARSTO (2004) (*Particulate Matter Assessment for Policy Makers:* A NARSTO Assessment. P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England. ISBN 0 52 184287 5.

support reversing a $PM_{2.5}$ precursor presumption is included in section II.A.8 below.

This approach was retained from the proposal because of continued uncertainties regarding ammonia emission inventories and the effects of ammonia emission reductions. Ammonia emission inventories are presently very uncertain in most areas, complicating the task of assessing potential impacts of ammonia emissions reductions. In addition, data necessary to understand the atmospheric composition and balance of ammonia and nitric acid in an area are not widely available across $PM_{2.5}$ nonattainment areas, making it difficult to predict the results of potential ammonia emission reductions. Ammonia reductions may be effective and appropriate for reducing $PM_{2.5}$ concentrations in selected locations, but in other locations such reductions may lead to minimal reductions in $PM_{2.5}$ concentrations and increased atmospheric acidity. Research projects continue to expand our collective understanding of these issues, but at this time EPA believes this case-by-case policy approach is appropriate. In light of these uncertainties, we encourage States to continue efforts to better understand the role of ammonia in its fine particle problem areas.

c. Comments and Responses

Comment: One commenter stated that scientific understanding of the complexities of PM formation from ammonia is limited. The commenter claimed that the reduction of ammonia will not reduce PM in many areas, and speciated PM data to investigate the potential decrease in PM from ammonia emissions reductions is not available in all areas.

Response: The final rule takes these uncertainties into consideration by allowing ammonia to be addressed on a case-by-case basis. For any area about which enough information is available to determine that ammonia emission reductions would lead to a beneficial reduction in $PM_{2.5}$, the State can develop a technical demonstration justifying the control of ammonia. If the State chooses to develop such a demonstration, preferably it should be completed as part of the SIP development process and prior to the adoption of control measures, in consultation with the appropriate EPA regional office.

Comment: Some commenters claimed that requiring no action on some precursors is counter to the requirement in sections 172(a)(2) and 188 to attain the NAAQS as expeditiously as practicable. They also asserted that presuming that ammonia is not a $PM_{2.5}$ attainment plan precursor violates 302(g) by improperly delegating authority to the States.

Response: In many areas, reducing ammonia emissions could have little effect on $PM_{2.5}$ concentrations and could lead to the potentially harmful effect of increased atmospheric acidity. While States are not required to take action on ammonia sources under this policy, States would be required to address information on ammonia brought to their attention during the planning and rule adoption process. Under this approach, States should assess whether ammonia reductions would lead to reduced $PM_{2.5}$ concentrations in specific nonattainment areas. If the State decides that ammonia reductions could yield beneficial reductions in $PM_{2.5}$, the State should complete a technical demonstration supporting a reversal of the presumption. The EPA does not believe that this approach improperly delegates authority to the States. It establishes a general presumption for all areas through this rulemaking process, and allows for the presumption to be modified by the State or EPA on a case-by-case basis. EPA still retains the ability to make a technical demonstration for any area if appropriate to reverse the presumption and require ammonia to be addressed in its attainment plan.

Comment: Some commenters stated that the results of a large study on air emissions from concentrated animal feeding operations (CAFOs) should be evaluated before requiring control of ammonia in areas where agriculture is alleged to be a major source.

Response: The $15 million national CAFO consent agreement study coordinated by Purdue University will greatly improve ammonia and VOC emissions inventories and our understanding of the impacts of agricultural emissions on particle formation. The EPA recognizes that the agricultural emissions study is expected to provide data for future planning purposes, and we expect that some of the results of the study will not be available in time to be considered in the development of $PM_{2.5}$ State Implementation Plans dues in April 2008. However, if a State believes it has sufficient technical information to warrant regulation of ammonia emissions in their 2008 implementation plans, it may include in its plan a demonstration to reverse the presumption as well as emission reduction measures. The EPA will review each submittal on a case-by-case basis.

Comment: A presumption to not address ammonia will impede certain states (*i.e.* those that have provisions requiring their regulations to be ''no stricter than Federal'' provisions) from regulating ammonia.

Response: This presumptive approach to ammonia will not restrict States from addressing ammonia in their $PM_{2.5}$ attainment plans. If a State has information indicating that reductions in ammonia emissions would cause beneficial reductions in $PM_{2.5}$ concentrations, the State can make a technical demonstration to reverse the presumption. In such cases, inclusion of ammonia as a $PM_{2.5}$ attainment plan precursor would not be considered stricter than Federal requirements. Under the policy in the final rule, the Federal government or the State may assess the impact of ammonia in a particular area and determine whether the presumption of insignificance is appropriate or whether ammonia is in fact a significant contributor to the $PM_{2.5}$ problem in the area.

4. Policy for VOC

[Section II.E.2 of November 1, 2005 proposed rule (70 FR 65999); sec. 51.1002 in draft and final regulatory text.]

a. Background

The VOC policy in this rule addresses volatile and semivolatile organic compounds, generally up to 24 carbon atoms. High molecular weight organic compounds (typically 25 carbon atoms or more) are emitted directly as primary organic particles and exist primarily in the condensed phase at ambient temperatures. Accordingly, high molecular weight organic compounds are to be regulated as primary $PM_{2.5}$ emissions for the purposes of the $PM_{2.5}$ implementation program.

The organic component of ambient particles is a complex mixture of hundreds or even thousands of organic compounds. These organic compounds are either emitted directly from sources (i.e. primary organic aerosol) or can be formed by reactions in the ambient air (i.e. secondary organic aerosol, or SOA). Volatile organic compounds are key precursors in the formation processes for both SOA and ozone. The relative importance of organic compounds in the formation of secondary organic particles varies from area to area, depending upon local emissions sources, atmospheric chemistry, and season of the year.

The lightest organic molecules (i.e., molecules with six or fewer carbon atoms) occur in the atmosphere mainly as vapors and typically do not directly

form organic particles at ambient temperatures due to the high vapor pressure of their products. However, they participate in atmospheric chemistry processes resulting in the formation of ozone and certain free radical compounds (such as the hydroxyl radical [OH]) which in turn participate in oxidation reactions to form secondary organic aerosols, sulfates, and nitrates. These VOCs include all alkanes with up to six carbon atoms (from methane to hexane isomers), all alkenes with up to six carbon atoms (from ethene to hexene isomers), benzene and many low-molecular weight carbonyls, chlorinated compounds, and oxygenated solvents.

Intermediate weight organic molecules (i.e., compounds with 7 to 24 carbon atoms) often exhibit a range of volatilities and can exist in both the gas and aerosol phase at ambient conditions. For this reason they are also referred to as semivolatile compounds. Semivolatile compounds react in the atmosphere to form secondary organic aerosols. These chemical reactions are accelerated in warmer temperatures, and studies show that SOA typically comprises a higher percentage of carbonaceous PM in the summer as opposed to the winter. The production of SOA from the atmospheric oxidation of a specific VOC depends on four factors: Its atmospheric abundance, its chemical reactivity, the availability of oxidants (O_3, OH, HNO_3), and the volatility of its products. In addition, recent work suggests that the presence of acidic aerosols may lead to an increased rate of SOA formation. Aromatic compounds such as toluene, xylene, and trimethyl benzene are considered to be the most significant anthropogenic SOA precursors and have been estimated to be responsible for 50 to 70 percent of total SOA in some airsheds. Man-made sources of aromatics gases include mobile sources, petrochemical manufacturing and solvents. Some of the biogenic hydrocarbons emitted by trees are also considered to be important precursors of secondary organic particulate matter. Terpenes (and b-pinene, limonene, carene, etc.) and the sesquiterpenes are expected to be major contributors to SOA in areas with significant vegetation cover, but isoprene is not. Terpenes are very prevalent in areas with pine forests, especially in the southeastern U.S. The rest of the anthropogenic hydrocarbons (higher alkanes, paraffins, etc.) have been estimated to contribute 5–20 percent to the SOA concentration depending on the area.

The contribution of the primary and secondary components of organic aerosol to the measured organic aerosol concentrations remains a complex issue. Most of the research performed to date has been done in southern California, and more recently in central California, while fewer studies have been completed on other parts of North America. Many studies suggest that the primary and secondary contributions to total organic aerosol concentrations are highly variable, even on short time scales. Studies of pollution episodes indicate that the contribution of SOA to the organic particulate matter can vary from 20 percent to 80 percent during the same day.

Despite significant advances in understanding the origins and properties of SOA, it remains probably the least understood component of $PM_{2.5}$. The reactions forming secondary organics are complex, and the number of intermediate and final compounds formed is voluminous. Some of the best efforts to unravel the chemical composition of ambient organic aerosol matter have been able to quantify the concentrations of hundreds of organic compounds representing only 10–20 percent of the total organic aerosol mass. For this reason, SOA continues to be a significant topic of research and investigation.

Current scientific and technical information clearly shows that carbonaceous material is a significant fraction of total $PM_{2.5}$ mass in most areas, that certain VOC emissions are precursors to the formation of secondary organic aerosol, and that a considerable fraction of the total carbonaceous material is likely from local as opposed to regional sources. However, while significant progress has been made in understanding the role of gaseous organic material in the formation of organic PM, this relationship remains complex. We recognize that further research and technical tools are needed to better characterize emissions inventories for specific VOC compounds, and to determine the extent of the contribution of specific VOC compounds to organic PM mass.

In light of these factors, the proposed rule did not require States to address VOCs as $PM_{2.5}$ attainment plan precursors and evaluate them for control measures, unless the State or EPA makes a finding that VOCs significantly contribute to a $PM_{2.5}$ nonattainment problem in the State or to other downwind air quality concerns. Many $PM_{2.5}$ nonattainment areas are also nonattainment areas for the 8-hour ozone standard; control measures for VOCs will be implemented in some of these areas, potentially providing a co-benefit for $PM_{2.5}$ concentrations.

b. Final Rule

The final rule maintains the same policy as proposed.[12] States are not required to address VOC in $PM_{2.5}$ implementation plans and evaluate control measures for such pollutants unless the State or EPA makes a technical demonstration that emissions of VOCs from sources in the State significantly contribute to $PM_{2.5}$ concentrations in a given nonattainment area. Technical demonstrations are discussed in section II.A.8 below. If a State chooses to make a technical demonstration, it should be developed in advance of the attainment demonstration.

c. Comments and Responses

Comment: One commenter stated that our understanding of the complexities of $PM_{2.5}$ formation from VOCs is limited, that speciated PM data are not available in all areas, and that VOC reductions will not reduce $PM_{2.5}$ in many areas.

Response: The EPA acknowledges the uncertainties regarding the role of VOC in secondary organic aerosol formation. For this reason the final rule does not presumptively include VOC as a regulated pollutant for PM planning. However, if available data demonstrates that control of VOC would reduce $PM_{2.5}$ concentrations in an area, the State or EPA may include VOC as an attainment plan precursor.

Comment: One commenter stated that the rationale that VOC should not be considered a $PM_{2.5}$ attainment plan precursor because most PM areas are also ozone areas is not appropriate because many ozone areas will attain soon and VOC reductions will still be needed for PM.

Response: The primary rationale for not including VOC as a $PM_{2.5}$ attainment plan precursor in every nonattainment area is the uncertainty regarding the contribution of anthropogenic VOCs to the formation of the organic carbon portion of fine particles. In certain areas, EPA expects that VOC control measures will have some co-benefits in the reduction of fine particulates. However, this reason should not be considered the principal reason for the policy in the final rule that VOCs presumptively should not be considered $PM_{2.5}$ attainment plan precursors. If a State or EPA determines that VOCs do contribute significantly to $PM_{2.5}$ concentrations in an area, the State will be required to evaluate control measures for VOC as a $PM_{2.5}$ attainment plan

[12] The policy is the same as proposed, with the clarification regarding downwind areas discussed above (Section A.2.b).

precursor for that area. This approach will provide for regulation of VOCs in locations where it is most appropriate.

Comment: One commenter suggested that EPA wait for the results of the pending agricultural emissions study before requiring control of VOCs in agricultural areas.

Response: The $15 million national CAFO consent agreement study coordinated by Purdue University will greatly improve ammonia and VOC emissions inventories and our understanding of the impacts of agricultural emissions on particle formation. The EPA recognizes that the agricultural emissions study is expected to provide data for future planning purposes, and we expect that some of the results of the study will not be available in time to be considered in the development of $PM_{2.5}$ State Implementation Plans dues in April 2008. However, if a State believes it has sufficient technical information to warrant regulation of VOC emissions in their 2008 implementation plans, it may include in its plan a demonstration to reverse the presumption as well as emission reduction measures. The EPA will review each submittal on a case-by-case basis.

5. Policy for NO_X

[Section II.E.2 of November 1, 2005 proposed rule (70 FR 65999); sec. 51.1002 in draft and final regulatory text.]

a. Background

The sources of NO_X are numerous and widespread. The combustion of fossil fuel in boilers for commercial and industrial power generation and in mobile source engines each account for approximately 30 percent of NO_X emissions in $PM_{2.5}$ nonattainment areas (based on 2001 emission inventory information). Nitrates are formed from the oxidation of oxides of nitrogen into nitric acid either during the daytime (reaction with OH) or during the night (reactions with ozone and water). Nitric acid continuously transfers between the gas and the condensed phases through condensation and evaporation processes in the atmosphere. However, unless it reacts with other species (such as ammonia, sea salt, or dust) to form a neutralized salt, it will volatilize and not be measured using standard $PM_{2.5}$ measurement techniques. The formation of aerosol ammonium nitrate is favored by the availability of ammonia, low temperatures, and high relative humidity. Because ammonium nitrate is semivolatile and not stable in higher temperatures, nitrate levels are typically lower in the summer months and higher in the winter months. The resulting ammonium nitrate is usually in the sub-micrometer particle size range. Reactions with sea salt and dust lead to the formation of nitrates in coarse particles. Nitric acid may be dissolved in ambient aerosol particles.

Based on a review of speciated monitoring data analyses, it is apparent that nitrate concentrations vary significantly across the country. For example, in some southeastern locations, annual average nitrate levels are in the range of 6 to 8 percent of total $PM_{2.5}$ mass, whereas nitrate comprises 40 percent or more of $PM_{2.5}$ mass in certain California locations. Nitrate formation is favored by the availability of ammonia, low temperatures, and high relative humidity. It is also dependent upon the relative degree of nearby SO_2 emissions because ammonia reacts preferentially with SO_2 over NO_X. NO_X reductions are expected to reduce $PM_{2.5}$ concentrations in most areas. However, it has been suggested that in a limited number of areas, NO_X control would result in increased $PM_{2.5}$ mass by disrupting the ozone cycle and leading to increased oxidation of SO_2 to form sulfate particles, which are heavier than nitrate particles. Because of the above factors, the proposed rule presumed that States must evaluate and implement reasonable controls on sources of NO_X in all nonattainment areas, but allowed for the State and EPA to develop a technical demonstration to reverse this presumption.

b. Final Rule

The EPA is retaining the proposed approach in the final rule.[13] Under this policy, States are required to address NO_X as a $PM_{2.5}$ attainment plan precursor and evaluate reasonable controls for NO_X in $PM_{2.5}$ attainment plans, unless the State and EPA make a finding that NO_X emissions from sources in the State do not significantly contribute to $PM_{2.5}$ concentrations in the relevant nonattainment area. This presumptive policy is consistent with other recent EPA regulations requiring NO_X reductions which will reduce fine particle pollution, such as the Clean Air Interstate Rule and a number of rules targeting onroad and nonroad engine emissions.

Technical demonstrations that would reverse the presumption should be developed in advance of the attainment demonstration and are discussed in section II.A.8 below.

[13] The policy is the same as proposed, with the clarification regarding downwind areas discussed above (Section A.2.b).

c. Comments and Responses

Comment: Most commenters generally agreed with the proposed inclusion of NO_X as a presumptive $PM_{2.5}$ attainment plan precursor.

Response: The EPA agrees with these commenters.

Comment: Some commenters requested guidance on what would constitute an acceptable demonstration to reverse the presumption that NO_X is a $PM_{2.5}$ attainment plan precursor.

Response: Guidance on technical demonstrations to reverse the presumptive inclusion of NO_X in all state implementation plans is discussed in section II.A.8 below.

Comment: One commenter raised concerns that the proposed policy for NO_X would allow a State to find NO_X to be an insignificant contributor to an area's $PM_{2.5}$ nonattainment problem and effectively keep the State from controlling the area's NO_X emissions for other purposes, such as to address interstate transport under section 110 of the CAA. Section 110 requires SIPs to prohibit emissions within the State that would contribute significantly to another State's nonattainment problem or interfere with another State's maintenance plan.

Response: The identification of precursors for regulation under this rule is for purposes of $PM_{2.5}$ nonattainment and maintenance plans under Part D of the CAA. The $PM_{2.5}$ implementation rule does not prevent a State from regulating NO_X sources under any other Federal or State rule, including interstate transport rules under Section 110.

6. Policy for SO_2

[Section II.E.2 of November 1, 2005 proposed rule (70 FR 65999); sec. 51.1002 in draft and final regulatory text.]

a. Background

Sulfur dioxide is emitted mostly from the combustion of fossil fuels in boilers operated by electric utilities and other industry. Less than 20 percent of SO_2 emissions nationwide are from other sources, mainly other industrial processes such as oil refining and pulp and paper production. The formation of sulfuric acid from the oxidation of SO_2 is an important process affecting most areas in North America. There are three different pathways for this transformation.

First, gaseous SO_2 can be oxidized by the hydroxyl radical (OH) to create sulfuric acid. This gaseous SO_2 oxidation reaction occurs slowly and only in the daytime. Second, SO_2 can

dissolve in cloud water (or fog or rain water), and there it can be oxidized to sulfuric acid by a variety of oxidants, or through catalysis by transition metals such as manganese or iron. If ammonia is present and taken up by the water droplet, then ammonium sulfate will form as a precipitate in the water droplet. After the cloud changes and the droplet evaporates, the sulfuric acid or ammonium sulfate remains in the atmosphere as a particle. This aqueous phase production process involving oxidants can be very fast; in some cases all the available SO_2 can be oxidized in less than an hour. Third, SO_2 can be oxidized in reactions in the particle-bound water in the aerosol particles themselves. This process takes place continuously, but only produces appreciable sulfate in alkaline (dust, sea salt) coarse particles. Oxidation of SO_2 has also been observed on the surfaces of black carbon and metal oxide particles. During the last 20 years, much progress has been made in understanding the first two major pathways, but some important questions still remain about the smaller third pathway. Models indicate that more than half of the sulfuric acid in the eastern United States and in the overall atmosphere is produced in clouds.

The sulfuric acid formed from the above pathways reacts readily with ammonia to form ammonium sulfate, $(NH_4)_2SO_4$. If there is not enough ammonia present to fully neutralize the produced sulfuric acid (one molecule of sulfuric acid requires two molecules of ammonia), part of it exists as ammonium bisulfate, NH_4HSO_4 (one molecule of sulfuric acid and one molecule of ammonia) and the particles are more acidic than ammonium sulfate. In certain situations (in the absence of sufficient ammonia for neutralization), sulfate can exist in particles as sulfuric acid, H_2SO_4. Sulfuric acid often exists in the plumes of stacks where SO_2, SO_3, and water vapor are in much higher concentrations than in the ambient atmosphere, but these concentrations become quite small as the plume is cooled and diluted by mixing.

Because sulfate is a significant contributor (e.g. ranging from 9 percent to 40 percent) to $PM_{2.5}$ concentrations in nonattainment areas and to other air quality problems in all regions of the country, EPA proposed that States would be required to address sulfur dioxide as a $PM_{2.5}$ attainment plan precursor in all areas.

b. Final Rule

The final rule includes the same policy for sulfur dioxide as in the proposal. States are required to address sulfur dioxide as a $PM_{2.5}$ attainment plan precursor and evaluate SO_2 for possible control measures in all areas. Sulfate is an important precursor to $PM_{2.5}$ formation in all areas, and has a strong regional impact on $PM_{2.5}$ concentrations. This policy is consistent with past EPA regulations, such as the CAIR, the Clean Air Visibility Rule, the Acid Rain rules, and the Regional Haze rule, that require SO_2 reductions to address fine particle pollution and related air quality problems.

Under the transportation conformity program, sulfur dioxide is not required to be addressed in transportation conformity determinations *before* a SIP is submitted unless either the state air agency or EPA regional office makes a finding that on-road emissions of sulfur dioxide are significant contributors to the area's $PM_{2.5}$ problem. Sulfur dioxide would be addressed *after* a $PM_{2.5}$ SIP is submitted if the area's SIP contains an adequate or approved motor vehicle emissions budget for sulfur dioxide. EPA based this decision on the *de minimis* level of sulfur dioxide emissions from on-road vehicles currently, and took into consideration the fact that sulfur dioxide emissions from on-road sources will decline in the future due to the implementation of requirements for low sulfur gasoline (which began in 2004) and for low sulfur diesel fuel (beginning in 2006). For more information, see the May 6, 2005 transportation conformity rule on $PM_{2.5}$ precursors at 70 FR 24283.

c. Comments and Responses

Comment: Most commenters agreed with the proposed policy for SO_2. One commenter stated, ''* * * requiring states to address sulfur dioxide in attainment planning in all areas is consistent with the science of $PM_{2.5}$ formation and essential to effective implementation of the $PM_{2.5}$ NAAQS.'' Another commenter concluded that EPA's proposal ''* * * is justified based on the fact that SO_2 has been found to be a significant contributor to $PM_{2.5}$ nonattainment in all areas.''

Response: The EPA agrees with these comments.

Comment: Some commenters believe States should be able to make a demonstration that SO_2 not be addressed as an attainment plan precursor. The commenters claim that the urban increment of sulfate is generally small, and SO_2 control will not matter in many areas. Commenters also note that a large percentage of the SO_2 emission inventory is being reduced and will be reduced further through existing programs, and that if attainment can be demonstrated without additional SO_2 controls, a State should be allowed to make that demonstration in its SIP. One commenter stated that whether SO_2 emissions from a given source located in a nonattainment area in fact contribute significantly to ambient concentrations of sulfate and $PM_{2.5}$ in that nonattainment area likely will depend on a range of factors, including source type, stack height, location, and meteorology. The commenter asserted that sulfate forms over significant geographic distances from the source of the SO_2 emissions and may not form significant concentrations of $PM_{2.5}$ in the local nonattainment area.

Response: As in the proposal, the final rule requires SO_2 to be considered a $PM_{2.5}$ attainment plan precursor in all cases. Sulfate is a significant fraction of $PM_{2.5}$ mass in all nonattainment areas currently, and although large SO_2 reductions are projected from electric generating units with the implementation of the CAIR program, sulfate is still projected to be a key contributor to $PM_{2.5}$ concentrations in the future. SO_2 emissions also lead to sulfate formation on both regional and local scales. The EPA agrees that the extent of the contribution from a particular source in a nonattainment area to $PM_{2.5}$ concentrations in the area will depend on a number of factors, and that at times the reaction of SO_2 emissions in the atmosphere to form sulfate particles may occur less rapidly and extend over a significant distance. However, at other times the conversion of SO_2 to sulfate can occur rapidly and local impacts from a particular source can be more significant. States are required to develop plans to attain as expeditiously as practicable through the identification of technically and economically feasible control measures from the full range of source categories contributing to $PM_{2.5}$ nonattainment areas. In developing these plans, each State will need to consider whether controls on local SO_2 sources would be cost-effective and would be needed to attain expeditiously.

7. Policy for Direct PM

[Section II.E.2 of November 1, 2005 proposed rule (70 FR 65999); sec. 51.1002 in draft and final regulatory text.]

a. Background

This section addresses inorganic and organic forms of directly emitted PM. Although these direct emissions are by definition not precursors to $PM_{2.5}$, this section is included to provide information on the full range of

components that commonly make up fine particulate matter.

The main anthropogenic sources of inorganic (or crustal) particles are: entrainment by vehicular traffic on unpaved or paved roads; mechanical disturbance of soil by highway, commercial, and residential construction; and agricultural field operations (tilling, planting and harvesting). Industrial processes such as quarries, minerals processing, and agricultural crop processing can also emit crustal materials. While much of these emissions are coarse PM, the size distribution can have a tail of particles smaller than $PM_{2.5}$.

In general, coarse PM is most important close to the source, and not generally a significant contributor to regional scale PM problems. Even so, during certain high wind events, fine crustal PM has been shown to be transported over very long distances.

Emission estimates of mechanically suspended crustal PM from sources within the U.S. are often quite high. However, this PM is often released very close to the ground, and with the exception of windblown dust events, thermal or turbulent forces sufficient to lift and transport these particles very far from their source are not usually present. Thus, crustal material is only a minor part of $PM_{2.5}$ annual average concentrations.

Primary carbonaceous particles are largely the result of incomplete combustion of fossil or biomass fuels. This incomplete combustion usually results in emissions of both black carbon and organic carbon particles. High molecular weight organic molecules (i.e., molecules with 25 or more carbon atoms) are either emitted as solid or liquid particles, or as gases that rapidly condense into particle form. These heavy organic molecules sometimes are referred to as volatile organic compounds, but because their characteristics are most like direct PM emissions, they will be considered to be primary emissions for the purposes of this regulation. Primary organic carbon also can be formed by condensation of semi-volatile compounds on the surface of other particles.

The main combustion sources emitting carbonaceous $PM_{2.5}$ are certain industrial processes, managed burning, wildland fires, open burning of waste, residential wood combustion, coal and oil-burning boilers (utility, commercial and industrial), and mobile sources (both onroad and nonroad). Certain organic particles also come from natural sources such as decomposition or crushing of plant detritus. Most combustion processes emit more organic particles than black carbon particles. A notable exception to this is diesel engines, which typically emit more black carbon particles than organic carbon. Because photochemistry is typically reduced in the cooler winter months for much of the country, studies indicate that the carbon fraction of PM mass in the winter months is likely dominated by direct PM emissions as opposed to secondarily formed organic aerosol.

Particles from the earth's crust may contain a combination of metallic oxides and biogenic organic matter. The combustion of surface debris will likely entrain some soil. Additionally, emissions from many processes and from the combustion of fossil fuels contain elements that are chemically similar to soil. Thus, a portion of the emissions from combustion activities may be classified as crustal in a compositional analysis of ambient $PM_{2.5}$. The proposed rule required that States address the direct emissions of particulate matter in their $PM_{2.5}$ attainment plans. During the comment period, EPA received several comments regarding the definition of what should be regulated as ''direct $PM_{2.5}$.''

b. Final Rule

This rule defines direct $PM_{2.5}$ emissions as ''air pollutant emissions of direct fine particulate matter, including organic carbon, elemental carbon, direct sulfate, direct nitrate, and miscellaneous inorganic material (i.e. crustal material).'' Development of attainment plans will include direct $PM_{2.5}$ emissions and specific $PM_{2.5}$ attainment plan precursors.

c. Comments and Responses

Comment: A few commenters noted that 40 CFR 51.1000 of the proposed rule includes definitions for both ''direct $PM_{2.5}$ emissions'' and for ''$PM_{2.5}$ direct emissions.'' They recommend including just one definition in the final rule.

Response: The EPA acknowledges this oversight and has included in the final rule a single definition for ''direct $PM_{2.5}$ emissions.'' It reads: ''Direct $PM_{2.5}$ emissions means solid particles emitted directly from an air emissions source or activity, or gaseous emissions or liquid droplets from an air emissions source or activity which condense to form particulate matter at ambient temperatures. Direct $PM_{2.5}$ emissions include elemental carbon, directly emitted organic carbon, directly emitted sulfate, directly emitted nitrate, and other inorganic particles (including but not limited to crustal material, metals, and sea salt).''

8. Optional Technical Demonstrations for NO_X, VOC, and Ammonia

[Section II.E.2 of November 1, 2005 proposed rule (70 FR 65999); sec. 51.1002 in draft and final regulatory text.]

a. Background

The proposed rule required States to evaluate and consider control strategies for sources of SO_2 and direct $PM_{2.5}$ emissions in all nonattainment areas. For the precursors NO_X, VOC, and ammonia, the proposed rule included presumptive policies that could be reversed with an acceptable technical demonstration by the State or EPA. (The policy in the proposal presumptively required that NO_X emissions must be addressed in all areas, and that VOC and ammonia emissions do not need to be addressed in all areas.) A number of commenters requested additional guidance on the criteria for an acceptable technical demonstration.

b. Final Rule

The final rule retains provisions for the State or EPA to conduct a technical demonstration to reverse the presumptive inclusion of NO_X or to reverse the presumptive exclusions of ammonia and VOC as $PM_{2.5}$ attainment plan precursors. Demonstrations to reverse the presumptions for ammonia, VOC, or NO_X are to be based on the weight of evidence of available information, and any demonstration by the State must be approved by EPA. The State must demonstrate that based on the sum of available technical and scientific information, it would be appropriate for a nonattainment area to reverse the presumptive approach for a particular precursor. The demonstration should include information from multiple sources, including results of speciation data analyses, air quality modeling studies, chemical tracer studies, emission inventories, or special intensive measurement studies to evaluate specific atmospheric chemistry in an area.

Because of the variation among nonattainment areas in terms of such factors as local emissions sources, growth patterns, topography, and severity of the nonattainment problem, EPA believes that it would not be appropriate to define a prescriptive set of analyses that must be included in all $PM_{2.5}$ precursor technical demonstrations. The key criterion is that any technical demonstration must fairly represent available information.

In developing the implementation plan for a nonattainment area, the State should use all relevant information

available (from EPA, the State, or other sources) to determine the scientifically most appropriate approach to regulating NO_X, ammonia, and VOC emissions in the area. As required under any State rulemaking process, the State must consider and provide a response in the record to any information or evidence brought forward by commenters during the SIP planning, development and review process which indicates that the presumption for a precursor should be reversed. In its review of the forthcoming State implementation plan submittal, EPA will review the State's proposed precursor policies in light of all currently available information. If information brought forward by commenters or the State in the SIP development process shows that the presumption in this rule for ammonia, VOC or NO_X is not technically justified for a particular nonattainment area, the State must conduct a technical demonstration to reverse the presumption. In the case of ammonia or VOC, the State then would evaluate control measures and implement those measures that are technically and economically feasible and that will contribute to expeditious attainment of the standards.

In the section below we suggest examples of the types of analyses that would be appropriate to use in developing such a demonstration. States are encouraged to consult with EPA in formulating appropriate technical demonstrations.

i. *Emission Inventory Information:* An analysis might show that a precursor composes a significant fraction of the emissions inventory in an area and therefore requires greater consideration.

Example: Several stationary sources emitting particular VOCs known to contribute to SOA formation make up a significant portion of the area's VOC inventory. This analysis may be useful in conjunction with other analyses included in a weight of evidence demonstration.

ii. *Speciation Data Information:* Analysis of data from speciation networks might lead a State to determine the relative importance of a precursor to seasonal or yearly average PM concentrations. Individual precursors require different approaches. Collection of new data could be used to understand the impacts of precursors in an area.

Example: Nitrate ion is a large portion of winter average $PM_{2.5}$ mass. Nitrate ion is a major portion of $PM_{2.5}$ mass on the 10 highest $PM_{2.5}$ days in winter in the past 3 years. The days with the highest mass concentrations might be indicative of inversion conditions and/or local impacts, rather than large-scale transport processes. For these reasons, nitrate should be addressed in the $PM_{2.5}$ attainment plan.

Example: Ammonium ion data combined with total calculated nitrate data indicates that reductions in ammonia would reduce PM concentrations without a sharp related increase in particle acidity. PM speciation data shows that PM in the area is generally within 10% of calculated neutralization. In places for which the needed atmospheric data are available to determine whether increased acidity is estimated to lead to negative environmental effects, analysis showing that increased acidity of particles and precipitation would likely result from ammonia reductions would support the presumption against ammonia regulation. Analysis showing that ammonia reductions would be unlikely to increase the acidity of particles and precipitation, and that potential reductions in ammonia would significantly reduce $PM_{2.5}$ levels, would support a technical demonstration to reverse the presumption.

iii. *Modeling Information:* Results of atmospheric modeling may help a State characterize the impacts of potential precursor emission reductions on $PM_{2.5}$ concentrations in an area.

Example: Modeling of SO_2, NO_X, and VOC emission reductions result in lower sulfate and nitrate levels but not lower secondary organic aerosol levels. This likely indicates that VOC reductions are not as vital as reductions of the other precursors.

Example: Modeled reductions of NO_X show a potential increase in sulfate formation through disruption of the ozone cycle. SO_2 reductions may be a better choice than NO_X reductions.

Example: Modeled ammonia reductions show a projected reduction in $PM_{2.5}$ concentrations in selected areas. Although dependant on good quality inventory data, this type of an analysis would indicate that the area is ammonia-limited and that ammonia reductions may be beneficial.

Example: Modeling shows that reductions in SO_2 in the absence of NO_X reductions in an area will not result in a significant $PM_{2.5}$ reduction because more nitrate particles form when less SO_2 is available for particle formation. However, $PM_{2.5}$ reductions are significant when both SO_2 and NO_X are reduced concurrently. This analysis would indicate that NO_X reductions should be included in the $PM_{2.5}$ attainment plan for the area.

iv. *Monitoring, Data Analysis, or Other Special Studies:* Could include monitoring of gases and compounds not typically monitored under the $PM_{2.5}$ speciation network, receptor modeling analysis, or special monitoring studies.

Example: Data from specialized monitoring studies can provide insights about concentrations of ammonia gas and nitric acid in an area and whether the area is ammonia-limited or not. Ammonia reductions in ammonia-limited areas typically yield reductions in $PM_{2.5}$ concentrations. Specialized monitoring and laboratory studies can also assess the relative concentrations of organic compounds and provide insights into the contributions of different anthropogenic and biogenic VOCs to secondary organic aerosol formation.

Example: Receptor modeling and statistical analysis $PM_{2.5}$ speciation monitoring data can indicate relative contributions to $PM_{2.5}$ mass from sources with different chemical ''fingerprints.''

Example: Additional analysis of organic compounds on filters collected through speciation monitoring may reveal insights about the relative degree of carbonaceous material considered to be from fossil fuel combustion as opposed to combustion of ''modern'' material (such as wood or biomass).

c. Comments and Responses

Comment: A number of commenters requested that the final rule include guidance on acceptable technical demonstrations.

Response: The above section includes examples designed to help States formulate appropriate demonstrations. Prescribing specific technical indicators to be used in all areas would ignore the scientific uncertainty inherent in the relationships between precursor emissions and the responses of atmospheric concentrations of $PM_{2.5}$. Therefore, States are encouraged to review available information and consult with EPA in formulating technical demonstrations appropriate to a particular area.

B. No Classification System

1. No Classification System

a. Background

Section 172 of subpart 1 contains the general requirements for SIPs for all nonattainment areas. Section 172(a)(1) states that on or after the date of designation, the Administrator may classify an area for the purpose of applying an attainment date or for some other purpose. Thus, a classification system is allowed under section 172 of the CAA, but is not required for the purposes of implementing a national ambient air quality standard. The CAA also states that EPA may consider certain factors in making a decision concerning classification for areas, such as the severity of nonattainment in such areas, and the availability and feasibility of the pollution control measures that may be needed to achieve attainment. In the proposed rule, EPA provided two implementation approaches for classifying $PM_{2.5}$ nonattainment areas. Under the first approach, there would be no classification system. Under the second approach, a two-tiered classification system would apply, with areas classified as either ''moderate'' or ''serious'' based on specific criteria.

For example, the two classification tiers could be based on the severity of nonattainment (e.g., serious areas would be those with a design value above a specific threshold), or on the attainment date for the area (e.g., serious areas would be those with attainment dates after April 2010). However, any moderate area that needs an attainment date longer than 5 years would be reclassified as serious. This would ensure that areas with a more persistent $PM_{2.5}$ problem are subject to more stringent requirements, even if they are not one of the areas with the highest current design values. For such areas, the State would be required to request reclassification for an area and ensure that the 2008 attainment SIP submission for the area includes all measures needed to meet the serious area requirements. Under the two tiered classification approach, we proposed that serious $PM_{2.5}$ nonattainment areas would be required to meet the more stringent requirements than moderate areas that would be defined in this rulemaking action (e.g., lower thresholds for RACT, fixed percentage reduction for RFP, etc.). For serious areas, the attainment date would be as expeditious as practicable, but no later than 10 years after designation, depending on the year in which the area would be projected to attain considering existing control requirements and the effect of RACM, RACT and RFP.

b. Final Rule

The EPA believes that in the case of $PM_{2.5}$, the no-classification approach is the most appropriate approach. An advantage of this approach is that it provides a relatively simple implementation structure for State implementation of the $PM_{2.5}$ standards, and avoids the need to define a classification system and determine classifications for each area. Without classifications, this rule still requires that that SIPs include all reasonable measures that contribute to achieving attainment as expeditiously as practicable. (Further detail is provided in sections D. and F. below.) Because of differences in the nature and sources of the $PM_{2.5}$ problem in different parts of the country, EPA did not find it appropriate to establish a tiered classification system with increasing control measure requirements. The no-classifications approach provides States with greater flexibility to determine the control strategies that will be most effective and efficient in bringing specific areas into attainment as expeditiously as practicable. In addition, EPA believes that States requesting additional time to attain the standard beyond the initial 5 year attainment date, provided for under Subpart I, will need to adopt additional or more stringent measures to meet their obligations for RACT, RACM and attainment that is as expeditious as practicable. We believe that this addresses the main concerns of those commenters who contend that a two tiered classification system should be implemented.

c. Comments and Responses

Comment: The majority of the commenters who commented on this issue stated that they agreed with EPA's preferred no classification approach. These commenters generally stated that they believed that EPA has the authority not to establish a classification system for $PM_{2.5}$ nonattainment areas. Some commenters stated that it would also be unreasonable, at this point in the process, for EPA to implement a classification scheme for the $PM_{2.5}$ standard. Many commenters support the no classification approach because it provides for a simple implementation structure and/or allows greater implementation flexibility to States, including flexibility to address specific problems related to individual nonattainment areas in the most cost-effective and expeditious manner, rather than through a one size fits all approach. Other commenters stated that they believe that a classification system is not needed because nonattainment areas in the Eastern United States are likely to attain the standard within a timeframe that is consistent with the timeframe established under Subpart 1.

Response: The EPA agrees with these commenters.

Comment: Several commenters disagreed with EPA's preferred approach and agreed with the two tiered classification approach featuring a ''moderate'' and a ''serious'' area classification. These commenters also stated that the threat of reclassification or ''bump up'' to a higher classification was a powerful incentive for areas to attain as expeditiously as practicable. Commenters also indicated that areas needing more time to attain the standard should be required to implement more stringent measures or mandatory measures.

Response: The EPA agrees that areas with more severe nonattainment problems will need to implement more stringent measures to attain. However, EPA does not believe that a classification system is needed to ensure that such measures are implemented. The EPA believes that on balance the no classification approach is the most appropriate classification option for the implementation of the $PM_{2.5}$ standard because of the difference in contributing sources from area to area.

Comment: Several commenters stated that under EPA's preferred approach, each State would be required to submit an attainment demonstration proposing an attainment date that is ''as expeditious as practicable'' for each area. They asserted that to allow States to propose their own attainment dates would invite delay in the process of cleaning up fine particle pollution. These commenters further stated that States would have no incentive to set an attainment date earlier than the outer limit set by EPA, even if it would be practicable to attain the NAAQS sooner.

Response: Section 172 of the CAA requires SIPs to demonstrate attainment as expeditiously as practicable regardless of whether there is a classification system, and under this rule states must justify that their attainment date is as expeditious as practicable considering all reasonable measures. As noted above, EPA believes that States requesting additional time to attain the standard beyond the initial 5 year attainment date will need to adopt additional or more stringent measures to meet their obligations for RACT and RACM and to attain as expeditiously as practicable. More details on the analytical process required for an attainment demonstration is included in section II.F.

Comment: Several commenters stated that the CAA requires regulation of the $PM_{2.5}$ standard under Subpart 4 of Part D. These commenters state that EPA takes the position that it must regulate $PM_{2.5}$ under Subpart 1 of the CAA, which applies to nonattainment areas in general. The commenters state that section 7513, in Subpart 4 of Part D of the CAA, contains specific provisions for classification of particulate matter nonattainment areas, and that EPA must therefore regulate $PM_{2.5}$ under Subpart 4, which requires a moderate and serious area classification system. Other commenters argued that implementation of the $PM_{2.5}$ standard must proceed under Subpart 1 of Part D of Title I of the CAA and cannot be governed by Subpart 4 of Part D, which addresses the implementation of the PM_{10} standard which is a different pollutant than $PM_{2.5}$.

Response: The EPA finds that the $PM_{2.5}$ standard should be implemented under subpart I of the CAA, which is the general provision of the CAA related to NAAQS implementation. Part D of Title I of the CAA sets forth the requirements for SIPs needed to attain the national ambient air quality standards. Part D also includes a general provision under

Subpart I which applies to all NAAQS for which a specific subpart does not exist. Because the $PM_{2.5}$ standards were not established until 1997, the plan provisions found in section 172 of subpart 1 pertaining to plans for nonattainment areas apply. The EPA further agrees with comments stating that subpart 4 on its face applies only to the PM_{10} standard. In general, the emphasis in subpart 4 on reducing PM_{10} concentrations from certain sources of direct $PM_{2.5}$ emissions can be somewhat effective in certain $PM_{2.5}$ nonattainment areas but not in all. Contributions to $PM_{2.5}$ concentrations are typically from a complex mix of sources of primary emissions and sources of precursor emissions which form particles through reactions in the atmosphere. $PM_{2.5}$ also differs from PM_{10} in terms of atmospheric dispersion characteristics, chemical composition, and contribution from regional transport.

2. Rural Transport Classification Option

a. Background

The 8-hour ozone implementation program includes a ''rural transport classification'' for subpart 1 nonattainment areas. In the proposal for this rule we discussed whether an area classification of this type would be appropriate for the $PM_{2.5}$ implementation program in light of the fact that no currently designated $PM_{2.5}$ nonattainment area met the criteria similar to those that apply to rural transport areas under the ozone implementation program.

As addressed in the proposal, a $PM_{2.5}$ nonattainment area would qualify for the ''rural transport'' classification if it met criteria similar to those specified for rural transport areas for the 1-hour ozone standard under section 182(h). Section 182(h) defines ''rural transport'' areas as those areas that do not include, and are not adjacent to, any part of a Metropolitan Statistical Area (MSA) or, where one exists, a Consolidated Metropolitan Statistical Area (CMSA). Section 182(h) further limits the category to those areas whose own emissions do not make a significant contribution to pollutant concentrations in those areas, or in other areas.

As discussed in the preamble to the proposed rule, potential criteria for a State to identify an area for a rural transport classification under the $PM_{2.5}$ program could be similar to the criteria used in the ozone implementation program: A State with a $PM_{2.5}$ ''rural transport'' area would need to (1) demonstrate that the area meets the above criteria, (2) demonstrate using EPA approved attainment modeling that the nonattainment problem in the area is due to the ''overwhelming transport'' of emissions from outside the area, and (3) demonstrate that sources of $PM_{2.5}$ and its precursor emissions within the boundaries of the area do not contribute significantly to $PM_{2.5}$ concentrations that are measured in the area or in other areas.

An area which qualifies for the ''rural transport'' classification would only be required to adopt local control measures sufficient to demonstrate that the area would attain the standard by its attainment date ''but for'' the overwhelming transport of emissions emanating from upwind States. RFP requirements under subpart 1 would still apply to these areas. As with other nonattainment areas, rural transport nonattainment areas would be subject to NSR, transportation conformity, and general conformity requirements. In the proposal we solicited comments on whether it would be appropriate to establish less burdensome NSR requirements in the event that a classification for rural transport areas is adopted in the final rule. The EPA requested comment on whether this type of classification option is needed at all under the $PM_{2.5}$ implementation program.

b. Final Rule

The final rule does not include a rural transport classification. This type of classification was included in the CAA for purposes of implementing the ozone standards because of the phenomenon of the formation of high ozone levels far downwind in very rural locations, including on high elevation mountain peaks. In reviewing the currently designated $PM_{2.5}$ nonattainment areas, it appears that all areas but one are within or adjacent to a metropolitan area (*i.e.* core-based statistical area or consolidated statistical area), and thus would not meet the criteria discussed above. Although $PM_{2.5}$ concentrations are greatly affected by long-range transport of air pollution, it appears that nonattainment areas typically are located in urban areas and include significant local pollutant sources.

c. Comments and Responses

Comment: Several commenters stated that they do not support the adoption of a rural transport classification because it is not needed. Commenters stated that given the criteria for the rural transport classification, which greatly limits its applicability, few if any $PM_{2.5}$ nonattainment areas can qualify for the option. One commenter stated that EPA modeled the rural transport classification after the ''rural transport areas'' provision contained in subpart 2 of the CAA, which applies only to the ozone standard. The commenter further states that neither Subpart 1 nor 4 contain any statutory authority for such a classification.

Response: The EPA believes that it has sufficient statutory authority under the CAA to establish a rural transport classification, but we do not believe that such a classification is needed.

Comment: One commenter generally supported the rural transport concept and the proposed associated requirements, with the addition that data analysis be included as appropriate in the required technical demonstrations in addition to modeling. While no $PM_{2.5}$ area currently meets the requirements for the rural transport classification option, several commenters recommended that it be maintained for potential cases in which the $PM_{2.5}$ standards are made more stringent, or measured air quality in areas change in such a way that areas would qualify for the rural transport classification at a later date.

Response: The EPA does not agree that a rural transport classification is needed. The EPA will re-evaluate the need for such a classification as appropriate.

C. Due Dates and Basic Requirements for Attainment Demonstrations

a. Background

Part D of Title I of the CAA sets forth the requirements for SIPs needed to attain the national ambient air quality standards. Part D includes a general subpart 1 which applies to all NAAQS for which a specific subpart does not exist. The 1990 CAA Amendments do not include any subpart for $PM_{2.5}$ because the $PM_{2.5}$ standards were not yet established. The EPA has determined that for $PM_{2.5}$, the nonattainment area plan provisions found in section 172 of subpart 1 apply.

Section 172(b) of the CAA requires that at the time the Agency promulgates nonattainment area designations, the EPA must also establish a schedule for States to submit SIPs meeting the applicable requirements of section 172(c) and of section 110(a)(2) of the CAA. Nonattainment area designations were finalized in December 2004, and a supplemental notice was issued in April 2005. Consistent with section 172(b) of the CAA, 40 CFR 51.1002 of the proposed rule requires the State to submit its attainment demonstration and SIP revision within 3 years, or by April 2008.

Section 51.1006 of the proposed rule addresses the situation in which an area

is initially designated as attainment/unclassifiable but is later designated as nonattainment based on air quality data after the 2001–2003 period. Under such circumstances, the SIP submittal date would be 3 years from the effective date of the redesignation, and the attainment date would be as expeditiously as practicable but no later than 5 years from the effective date of the redesignation.

The section 172(c) requirements that States are to address under section 172(c) (including RACT, RACM, RFP, contingency measures, emission inventory requirements, and NSR) are discussed in later sections of this document. Section 110(a)(2) of the CAA requires all States to develop and maintain a solid air quality management infrastructure, including enforceable emission limitations, an ambient monitoring program, an enforcement program, air quality modeling, and adequate personnel, resources, and legal authority. Section 110(a)(2)(D) also requires State plans to prohibit emissions from within the State which contribute significantly to nonattainment or maintenance areas in any other State, or which interfere with programs under part C to prevent significant deterioration of air quality or to achieve reasonable progress toward the national visibility goal for Federal class I areas (national parks and wilderness areas). In order to assist States in addressing their obligations regarding regionally transported pollution, EPA has finalized the CAIR to reduce SO_2 and nitrogen oxide emissions from large electric generating units.[14]

To date, few states have submitted a SIP revision addressing the section 110(a)(2) requirements for the purposes of implementing the $PM_{2.5}$ standards. The EPA recognizes that this situation is due in part to the fact that there were a series of legal challenges to the PM standards which were not resolved until March 2002, at which time the standards and EPA's decision process were upheld (see section I.B. for further discussion of past legal challenges to the standards). To address the States' continuing obligation to address the requirements of section 110(a), 40 CFR 51.1002 of the proposed rule also required each State to address the required elements of section 110(a)(2) of the CAA as part of the SIP revision adopting its attainment plan, if it has not already done so. On March 10, 2005, EPA entered into a consent decree with Environmental Defense and American Lung Association concerning EPA's failure to find that States failed to submit SIPs to address the section 110(a)(2) requirements. As a part of that consent decree, by no later than October 8, 2008, EPA is required to publish a notice in the **Federal Register** related to its determinations of whether each State has submitted SIPs for $PM_{2.5}$ that meet the requirements as stated under section 110(a)(2) of the CAA.

b. Final Rule

The final rule maintains the regulatory approach described above.

c. Comments and Responses

There were no comments on this portion of the proposal.

D. Attainment Dates

1. Background on Statutory Requirements

Establishing attainment dates. Section 172(a)(2) states that an area's attainment date ''shall be the date by which attainment can be achieved as expeditiously as practicable, but no later than 5 years from the date such area was designated nonattainment * * *, except that the Administrator may extend the attainment date to the extent the Administrator determines appropriate, for a period no greater than 10 years from the date of designation as nonattainment considering the severity of nonattainment and the availability and feasibility of pollution control measures.''

Since $PM_{2.5}$ designations have an effective date of April 5, 2005, the initial 5-year attainment date for $PM_{2.5}$ areas would be no later than April 5, 2010. For an area with an attainment date of April 5, 2010, EPA would determine whether it had attained the standard by evaluating air quality data from the three previous calendar years (i.e. 2007, 2008, and 2009).

For any areas that are granted the full 5 year attainment date extension under section 172, the attainment date would be no later than April 5, 2015. For such areas, EPA would determine whether they have attained the standard by evaluating air quality data from 2012, 2013, and 2014. Section 51.1004 of the proposed regulations addressed the attainment date requirement. Section 51.1004(b) provided that in their attainment demonstrations, States would propose an attainment date representing attainment as expeditiously as practicable based upon implementation of existing Federal and State measures, and all new reasonable local and intrastate measures. The EPA would approve a particular attainment date based on its review of the attainment demonstration.

Determining Whether an Area Has Attained. The EPA has the responsibility for determining whether a nonattainment area has attained the standard by its applicable attainment date. Section 179(c)(1) of the Act requires EPA to make determinations of attainment no later than 6 months following the attainment date for the area. Under section 179(c)(2), EPA must publish a notice in the **Federal Register** identifying those areas which failed to attain by the applicable attainment date. The statute further provides that EPA may revise or supplement its determination of attainment for the affected areas based upon more complete information or analysis concerning the air quality for the area as of the area's attainment date.

Section 179(c)(1) of the Act provides that the attainment determination for an area is to be based upon an area's ''air quality data as of the attainment date.'' The EPA will make the determination of whether an area's air quality is meeting the $PM_{2.5}$ NAAQS by the applicable attainment date primarily based upon data gathered from the air quality monitoring sites which have been entered into EPA's Air Quality System (AQS) database. No special or additional SIP submittal will be required from the State for this determination.

A $PM_{2.5}$ nonattainment area's air quality status is determined in accordance with appendix N of 40 CFR part 50. To show attainment of the 24-hour and annual standards for $PM_{2.5}$, the most recent three consecutive years of data prior to the area's attainment date must show that $PM_{2.5}$ concentrations over a three-year period are at or below the levels of the standards. A complete year of air quality data, as described in part 50, Appendix N, comprises of all 4 calendar quarters with each quarter containing data from at least 75 percent of the scheduled sampling days. The annual standard for $PM_{2.5}$ is attained when the 3-year average annual mean concentration is less than or equal to 15.05 $\mu g/m^3$. The 24-hour standard for $PM_{2.5}$ is met when the average of 98th percentile values for three consecutive calendar years at each monitoring site is less than or equal to 65.5 $\mu g/m^3$.

The EPA will begin processing and analyzing data related to the attainment of $PM_{2.5}$ areas immediately after the applicable attainment date for the affected areas. Current EPA policy, under 40 CFR part 58, sets the deadline for submittal of air quality data into the AQS database for no later than 90 days after the end of the calendar year.

[14] More information on the Clean Air Interstate Rule (CAIR) is available at: *http://www.epa.gov/cair.*

While EPA may determine that an area's air quality data indicates that an area may be meeting the $PM_{2.5}$ NAAQS for a specified period of time, this does not eliminate the State's responsibility under the Act to adopt and implement an approvable SIP. If EPA determines that an area has attained the standard as of its attainment date, the area will remain classified as nonattainment until the State has requested, and EPA has approved, redesignation to attainment for the area.

In order for an area to be redesignated as attainment, the State must comply with the five requirements listed under section 107(d)(3)(E) of the Act. This section requires that:

—EPA has determined that the area has met the $PM_{2.5}$ NAAQS;
—EPA has fully approved the state's implementation plan;
—The improvement in air quality is due to permanent and enforceable reductions in emissions;
—EPA has fully approved a maintenance plan for the area;
—The State(s) containing the area have met all applicable requirements under section 110 and part D.

2. Establishing Attainment Dates

a. Background

The EPA proposed rule language on attainment dates that closely tracks the statutory language. In the preamble, EPA noted that the attainment date that is as expeditious as practicable should reflect the projected impact of existing national and State programs (e.g. partial implementation of the CAIR rule, final Acid Rain Program, motor vehicle tier II standards and heavy-duty diesel engine standards, NO_X SIP call, State legislation such as Clean Smokestacks bill in North Carolina) as well as additional reasonable measures required for the $PM_{2.5}$ nonattainment SIP.

With respect to its authority to extend an area's date beyond 5 years, EPA stated in the preamble that the State can submit a SIP demonstrating that it is impracticable to attain by the 5-year attainment date: ''As stated previously, under section 172(a)(2)(A), EPA may grant an area an extension of the initial attainment date for a period of one to 5 years. States that request an extension of the attainment date under this provision of the CAA must submit a SIP by April 5, 2008 that includes, among other things, an attainment demonstration showing that attainment within 5 years of the designation date is impracticable. It must also show that the area will attain the standard by an alternative date that is as expeditious as practicable, but in no case later than 10 years after the designation date for the area (i.e. by April 5, 2015 for an area with an effective designation date of April 5, 2005). An appropriate extension in some cases may be only 1 or 2 years—a 5-year extension is not automatic upon request.

The attainment demonstration must provide sufficient information to show that attainment by the initial attainment date is impracticable due the severity of the nonattainment problem in the area, the lack of available control measures, and any other pertinent information related to these statutory criteria. States requesting an extension of the attainment date must also demonstrate that all local control measures that are reasonably available and technically feasible for the area are currently being implemented to bring about expeditious attainment of the standard by the alternative attainment date for the area. The State's plan will need to project the emissions reductions expected due to Federally enforceable national standards, State regulations, and local measures such as RACT and RACM, and then conduct modeling to project the level of air quality improvement in accordance with EPA's modeling guidance. The EPA will not grant an extension of the attainment date beyond the initial 5 years required by section 172(a)(2)(A) for an area if the State has not considered the implementation of all RACM and RACT local control measures for the area (see section III.I for a more detailed discussion of RACT and RACM). The EPA also will examine whether the State has adequately considered measures to address intrastate transport of pollution from sources within its jurisdiction. In attainment planning, States have the obligation and authority to address the transport of pollution from one area of the State to another. Any decision made by EPA to extend the attainment date for an area beyond its original attainment date will be based on facts specific to the nonattainment area at issue and will only be made after providing notice in the **Federal Register** and an opportunity for the public to comment.''

b. Final Rule

We are adopting the approach described above from the proposed rule. We also wish to clarify language that was in the preamble to the proposed rule regarding the criteria for an extension. The preamble stated that attainment date extensions would be based on the two statutory extension criteria—''the severity of nonattainment, and the availability and feasibility of pollution control measures,''—as well as ''other pertinent information which shows that additional time is required for the area to attain the standard.'' The CAA does not include this third clause and the regulatory text for the final rule does not include this third clause. The intent of this language in the preamble to the proposal was that States could include ''other pertinent information'' related to the two statutory criteria.

c. Comments and Responses

Comment: Some commenters expressed concern that EPA's preamble language appeared to assert a new basis for granting extensions not provided by the statute. They said EPA has authority to extend the attainment date under Section 7502(a)(2) based solely on consideration of two enumerated factors: the severity of nonattainment, and the availability and feasibility of control measures.

Response: The EPA agrees that extensions must be based upon the two factors in the statute, which are quite broad. A clarification of the preamble phrase cited by the commenter is provided above. The phrase in question—''any other pertinent information which shows that additional time is required for the area to attain the standard''—refers to information that relates to the two statutory factors.

Comment: One commenter stated that an area should qualify for an extension only if the area will implement stringent local controls, yet still cannot practicably attain by the five-year deadline. The commenter stated that at a minimum, EPA must require states to adopt RACM for both mobile and stationary sources before granting an extension. Another commenter said that given the difficulty many areas will have in meeting the five-year deadline for attainment of the $PM_{2.5}$ NAAQS (and especially in light of the fact that the deadline occurs only 2 years after states are to submit attainment SIPs), EPA should provide maximum flexibility in allowing extensions to the full 10-year period.

Response: The EPA agrees that extensions should be granted only if an area cannot practicably attain within 5 years despite application of all reasonable measures, including RACM. Although some measures can be implemented within a year or two, many measures require a longer period for installation of controls or full program implementation. In light of the limited time period between the SIP submittal deadline and the 5-year date, EPA believes that a significant number of areas may warrant extensions ranging from one to 5 years, with the length of

extension depending on the factors described above.

Comment: One commenter advocated that EPA include in this final rule a determination of those areas for which attainment within 5 years is impracticable. Another commenter advocated that EPA establish guidance based on EPA national modeling conducted last year to establish 2015 as constituting expeditious attainment for certain areas.

Response: The EPA is not determining in this rulemaking the areas that should receive extensions or should receive the maximum 10-year attainment date, for several reasons. First, EPA did not propose such an approach. Therefore, the public has not had the opportunity to comment on the approach or on the technical information on which EPA would make such judgments.

Second, EPA believes that modeling being conducted by the states, with updated inventories and finer grids, will generally provide a more reliable basis for projecting future $PM_{2.5}$ base case levels than national modeling conducted by EPA with older information. State modeling of future year $PM_{2.5}$ levels that has been conducted to date indicates that some areas will start closer or farther from the standard than EPA had projected.

Third, the SIP process provides a forum for states to identify reasonable controls and conduct analyses to determine the appropriate attainment date for an area. This process provides for input from expert stakeholders, the general public, other states which may share the same multi-State nonattainment area, and EPA on decisions regarding controls and attainment dates. At this time, EPA does not have the benefit of this process to inform a judgment as to when areas can practicably attain. States are responsible for developing RACM demonstrations; at this time, EPA lacks the information to conduct a credible RACM demonstration for all $PM_{2.5}$ nonattainment areas.

Fourth, no State commenter advocated that EPA attempt to make these judgments on attainment dates in advance of the State SIP process. The statute gives the states the lead in developing State implementation plans.

Comment: Another commenter recommends that an area should receive an attainment date extension when collectively the following conditions have been met:

- It is proven through modeling that the region is adversely effected by transport of $PM_{2.5}$ emissions from up wind sources beyond that State's control;
- A State has submitted and committed to implementing all Federal $PM_{2.5}$ emission reduction requirements in a timely manner; and,
- The extension concept is approved through the State air agency or through the MPO Interagency Consultation Process at the MPO level if applicable.

Response: This commenter advocates for attainment date extensions without any consideration of reasonable local measures. As stated above, EPA believes that extensions should be granted only if an area cannot practicably attain within 5 years despite application of all reasonable measures, including RACM. Although some measures can be implemented within a year or two, many measures may require a longer period for installation of controls or full program implementation. In light of the limited time period between the SIP submittal deadline and the 5-year date, EPA believes that a significant number of areas may warrant extensions ranging from one to 5 years, with the length of extension depending on the factors described above.

3. Attainment Dates: 1-Year Extensions

a. Background

Subpart 1 provides for States to request two 1-year extensions of the attainment date for a nonattainment area under limited circumstances. Section 172(a)(2)(C) of the CAA provides that EPA initially may extend an area's attainment date for 1 year, provided that the State has complied with all the requirements and commitments pertaining to the area in the applicable implementation plan, and provided that the area has had no more than a minimal number of ''exceedances'' of the relevant standard in the preceding year. Because the $PM_{2.5}$ standards do not have exceedance-based forms but are based on 3-year averaging periods, we interpret the air quality test in 40 CFR 51.1005 to mean that the area would need to have ''clean data'' for the third of the 3 years that are to be evaluated to determine attainment.[15] By this we mean that for the third year, the air quality for all monitors in the area as analyzed in accordance with Appendix N to 40 CFR part 50 each must have an annual average of 15.0 $\mu g/m^3$ or less, and a 98th percentile of 24-hour monitoring values of 65 $\mu g/m^3$ or less in order to qualify for a 1-year extension. (Given the rounding provisions specified in 40 CFR part 50, Appendix N, these criteria would be satisfied if the concentrations before final rounding are less than an annual average of 15.05 $\mu g/m^3$ and a 24-hour value of 65.5 $\mu g/m^3$.)

For example, suppose an area in violation of the annual standard has an attainment date of April 2010, and its annual average for 2007 was 15.8 and for 2008 was 15.6. If the annual average for the area in 2009 is 14.9, then the 3-year average would be 15.4, and it would not have attained the standard. We interpret section 172(a)(2)(C) as allowing the area to submit a request to EPA for a 1-year extension of its attainment date to 2011 (provided the State has also complied with its requirements and commitments) since the 14.9 ambient air quality value in the third year (2009) met the test of being at or below 15.0. Section 51.1005(a) of the proposed regulation addresses the initial 1-year attainment date extension.

The air quality measured in 2010 in conjunction with prior data will determine if the area attains the standard, qualifies for a second 1-year extension, or does not attain the standard. For example, if the area's annual average for 2010 is 14.3, then its 3-year average for 2008–2010 would be 14.9 and it would have met the annual standard.

If the area's annual average for 2010 is 14.9, however, then its 3-year average for 2008–2010 would be 15.1. In this situation the area would not have attained the standard, but the area would meet the air quality test for the second of the 1-year extensions allowed under section 172(a)(2)(C), because the 2010 annual average was at or below 15.0. Section 51.1005(b) of the proposed rule addresses the second 1-year attainment date extension. After obtaining a second 1-year extension, the State would evaluate whether the air quality values in 2011, in conjunction with 2009 and 2010 data, bring the area into attainment.

Pursuant to section 172(a)(2)(C), States must submit additional information to EPA to demonstrate that they have complied with applicable requirements, commitments, and milestones in the implementation plan. This information is needed in order for EPA to make a decision on whether to grant a 1-year attainment date extension. The EPA will not be inclined to grant a 1-year attainment date extension to an area unless the State can demonstrate that it has met important requirements contained in the area's implementation plan. States must demonstrate that: (1) Control measures have been submitted in the form of a SIP revision and substantially implemented to satisfy the requirements of RACT and RACM for the area, (2) the area has made emissions reductions progress that

[15] See section 51.1005 of the proposed regulation.

represents reasonable further progress (RFP) toward attainment of the NAAQS, and (3) trends related to recent air quality data for the area indicate that the area is in fact making progress toward attainment of the standard. Any decision made by EPA to extend the attainment date for an area will be based on facts specific to the nonattainment area at issue, and will only be made after providing notice in the **Federal Register** and an opportunity for the public to comment.

If an area fails to attain the standard by the attainment date, EPA would publish a finding to this effect in accordance with section 179 of the CAA. The area then would be required, within 1 year of publication of this finding, to develop a revised SIP containing additional emission reduction measures needed to attain the standard as expeditiously as practicable.

b. Final Rule

The final rule retains the proposed criteria for states to receive a 1-year attainment date extension for a nonattainment area.

c. Comments and Responses

Comment: A number of commenters supported EPA's ability to grant a 1-year attainment date extension if monitoring data indicate that the $PM_{2.5}$ levels during the most recent year were below 15.05 $\mu g/m^3$.

Response: The EPA agrees with these comments.

Comment: Some commenters recommended that a 1-year extension be provided if the trend line of the area's emissions levels or air quality data projects attainment in the extension year.

Response: The EPA believes that 1-year extensions should be based on air quality data, which can be assessed quickly after the end of the year. Basing such extensions solely on emissions trends would be impractical due to the longer turnaround time needed to evaluate emissions changes affecting a monitor.

Comment: One commenter believes the current requirement is overly stringent and inconsistent with the statute. The commenter believes that EPA's proposed approach incorrectly defines the statutory language referring to a ''minimal number of exceedances'' of the standard in the previous year as ''zero'' exceedances. Alternatively, the commenter suggests EPA could withdraw this provision and provide more detailed guidance giving the Agency and states some flexibility to demonstrate that exceedances were minimal in a given case since nothing in the statute requires the rigid definition of minimal that EPA proposes.

Response: The EPA believes the policy in the final rule is a reasonable application of the statutory language to a standard not based on exceedances. The EPA does not believe it would be appropriate to provide a 1-year extension to an area with air quality data showing it violating the standard over the 3 years prior to the attainment year.

4. Achieving ''Clean Data''

a. Background

Section III.D of the preamble to the proposed rule describes the incentives for attaining the standards prior to April 2008, when SIP submittals are due, or prior to an area's approved attainment date. Areas with design values just over the level of the standard may be able to achieve reductions in the local area or in the State so that, when their effect is considered in combination with reductions achieved under national programs, they may be sufficient to attain the standards before SIPs are due in 2008. For example, if monitoring in a nonattainment area shows that the air quality for 2004–2006 meets the standards, then the area may be subject to reduced regulatory requirements and be redesignated as ''attainment.''

The EPA issued a ''Clean Data'' policy memorandum in December 2004 describing possible reduced regulatory requirements for areas that attain the standards, but have not yet been redesignated as attainment.[16]

b. Final Rule

In the proposed rule, EPA indicated that it had issued this ''Clean Data'' policy to apply for purposes of the $PM_{2.5}$ standards. In this action EPA is finalizing as a rule the statutory interpretation that is embodied in the policy. Section 51.1004(c). The text of the final rule encapsulates the statutory interpretation set forth in the policy. Determinations as to whether individual areas have attained the $PM_{2.5}$ standard and thus qualify for application of the new clean data rule will be made in the context of rulemakings for those individual areas.

The preamble to the proposed rule mistakenly stated that if an area achieved ''clean data,'' it would be ''relieved of the requirements to implement the nonattainment NSR program otherwise required for nonattainment areas, and instead would implement the PSD program.'' The EPA wishes to clarify that the Clean Data Policy does not provide for suspension of the requirements for NSR nor for RACT. The provisions at issue in the Clean Data Policy include the requirements for an attainment demonstration and other related requirements, reasonable further progress, and contingency measures.

c. Comments and Responses

Comment: One commenter stated that EPA has absolutely no authority to waive NSR or any of the CAA's other requirements for nonattainment areas merely because a nonattainment area has 3 years of clean data, nor does EPA have authority to waive mandatory requirements of the CAA such as NSR, RACT, and RFP merely because EPA or the State claims they are not needed for attainment. The commenter believes that the only way that a nonattainment area can cease implementing controls and requirements mandated for such areas is to seek and obtain redesignation to attainment, and demonstrate in the process that the controls and requirements are not needed for maintenance of standards. The CAA has explicit procedures and prerequisites for redesignating nonattainment areas to attainment (CAA sections 107(d)(3)(E) and 175A). The EPA's ''clean data'' proposal would illegally circumvent those requirements.

Response: The Clean Data policy does not waive requirements for NSR nor for RACT. However, EPA believes that ''clean data'' policies for the ozone and fine particle programs are based on a reasonable interpretation of the CAA. The Clean Data Policy is the subject of two EPA memoranda setting forth our interpretation of the provisions of the Act as they apply to areas that have attained the relevant NAAQS. The EPA also finalized the statutory interpretation set forth in the policy in a final rule, 40 CFR 51.918, as part of its Final Rule to Implement the 8-Hour Ozone National Ambient Air Quality Standard—Phase 2 (Phase 2 Final Rule). See discussion in the preamble to the rule at 70 FR 71645–71646 (November 29, 2005). The legal rationale for the Clean Data policy is explained in our Phase 2 Final Rule, in our December 14, 2004 memorandum from Stephen D. Page entitled ''Clean Data Policy for the Fine Particle National Ambient Air Quality Standards'' (Page Memo), and in our May 10, 1995 memorandum from John S. Seitz, entitled ''Reasonable Further Progress, Attainment

[16] Memorandum of December 14, 2004, from Steve Page, Director, EPA Office of Air Quality Planning and Standards to EPA Air Division Directors, ''Clean Data Policy for the Fine Particle National Ambient Air Quality Standards.'' This document is available at: *http://www.epa.gov/pmdesignations/guidance.htm.*

Demonstration, and Related Requirements for Ozone Nonattainment Areas Meeting the Ozone National Ambient Air Quality Standard'' (Seitz memo). We adopt and reiterate those explications here.

The EPA has also explained its rationale for applying the Clean Data policy in rulemaking actions associated with nonattainment areas for the PM_{10} and 1-hour ozone standards. For rulemaking actions applying the Clean Data policy to the PM_{10} standards, see 71 FR 27440 (May 11, 2006) (Weirton, WVA), 71 FR 13021 (March 14, 2006) (Yuma, AZ), 71 FR 6352 (February 8, 2006) (Ajo, AZ). For a discussion of the legal rationale supporting rulemaking actions applying the Clean Data policy to the 1-hour ozone standards, see, for example, 67 FR 49600 (July 31, 2002); 65 FR 37879 (June 19, 2000) Cincinnati-Hamilton, Ohio-Kentucky); 61 FR 20458 (May 7, 1996) (Cleveland Akron-Lorain, Ohio); 66 FR 53094 (October 19, 2001) (Pittsburgh-Beaver Valley, Pennsylvania); 61 FR 31832 (June 21, 1996 (Grand Rapids, Michigan); 60 FR 36723 (July 18, 1995) (Salt Lake and Davis Counties, Utah); 68 FR 25418 (May 12, 2003) (St Louis, Missouri); 69 FR 21717 (April 22, 2004) (San Francisco Bay Area).

The EPA has further elaborated on its legal rationale for the Clean Data Policy in briefs filed in the 10th, 7th, and 9th Circuits, and hereby incorporates those briefs insofar as relevant here. See *Sierra Club* v. *EPA,* No. 95–9541 (10th Cir.), *Sierra Club* v. *EPA,* No. 03–2839, 03–3329 (7th Cir.), *Our Children's Earth Foundation* v. *EPA,* No. 04–73032 (9th Cir.). As stated in the policy, the attainment demonstration, RFP requirements, and contingency measure requirement are designed to bring an area into attainment. Once this goal has been achieved, it is appropriate to suspend the obligation that States submit plans to meet these goals, so long as the area continues to attain the relevant standard. The Tenth, Seventh and Ninth Circuits have all upheld EPA rulemakings applying the Clean Data Policy. See *Sierra Club* v. *EPA,* 99 F. 3d 1551 (10th Cir. 1996); *Sierra Club* v. *EPA,* 375 F. 3d 537 (7th Cir. 2004); *Our Children's Earth Foundation* v. *EPA,* No. 04–73032 (9th Cir. June 28, 2005 (Memorandum Opinion).

The EPA has explained in its memoranda on the Clean Data Policy for $PM_{2.5}$ and for ozone that it is reasonable to interpret the provisions regarding RFP and attainment demonstrations, along with certain other related provisions, as not requiring further submissions to achieve attainment for so long as the area is in fact attaining the standard. Under the policy, EPA is not granting an exemption from any applicable requirement under Part D. Rather, EPA has interpreted these requirements as not applying for so long as the area remains in attainment with the standard. This is not a waiver of requirements that by their terms apply; it is a determination that certain requirements are written so as to be operative only if the area is not attaining the standard.

CAA section 172(c)(2) provides that SIP provisions in nonattainment areas must require ''reasonable further progress.'' The term ''reasonable further progress'' is defined in section 171(1) as ''such annual incremental reductions in emissions of the relevant air pollutant as are required by this part or may reasonably be required by the Administrator for the purpose of ensuring attainment of the applicable NAAQS by the applicable date.'' Thus, by definition, the ''reasonable further progress'' provision requires only such reductions in emissions as are necessary to attain the NAAQS. If an area has attained the NAAQS, the purpose of the RFP requirement will have been fulfilled, and since the area has already attained, showing that the State will make RFP towards attainment will ''have no meaning at that point.'' The EPA's General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990 (General Preamble) 57 FR 13498, 13564 (April 16, 1992).

CAA section 172(c)(1), the requirement for an attainment demonstration, provides in relevant part that SIPs ''shall provide for attainment of the [NAAQS].'' The EPA has interpreted this requirement as not applying to areas that have reached attainment. If an area has attained the standard, there is no need to submit a plan demonstrating how the area will reach attainment. In the General Preamble (57 FR 13564), EPA stated that no other measures to provide for attainment would be needed by areas seeking redesignation to attainment since ''attainment will have been reached.'' See also Memorandum from John Calcagni, ''Procedures for Processing Requests to Redesignate Areas to Attainment,'' September 4, 1992, at page 6.

CAA section 172(c)(9) provides that SIPs in nonattainment areas ''[S]hall provide for the implementation of specific measures to be undertaken if the area fails to make reasonable further progress, or to attain the [NAAQS] by the attainment date applicable under this part. Such measures shall be included in the plan revision as contingency measures to take effect in any such case without further action by the State or [EPA].''

This contingency measure requirement is inextricably tied to the reasonable further progress and attainment demonstration requirements. Contingency measures are implemented if reasonable further progress targets are not achieved, or if attainment is not realized by the attainment date. Where an area has already achieved attainment by the attainment date, it has no need to rely on contingency measures to come into attainment or to make further progress to attainment. As EPA stated in the General Preamble:

> ''The section 172(c)(9) requirements for contingency measures are directed at ensuring RFP and attainment by the applicable date.'' 57 FR 13564. Thus these requirements no longer apply when an area has attained the standard.

It is important to note that should an area attain the $PM_{2.5}$ standards based on three years of data, its obligation to submit an attainment demonstration is not waived but is only suspended. If the area then has air quality concentrations in the following year such that the area exceeds the standard for years 2 through 4, then the area's obligation to submit an attainment demonstration is back in effect.

The determination of attainment contemplated by the Clean Data Policy does not purport to be a redesignation, and thus the requirements for redesignation under section 107(d) are not applicable. Nor does the Clean Data Policy avoid or illegally circumvent the redesignation requirements of section 107 of the CAA. All of the requirements for redesignation remain in effect and must be satisfied for an area to be redesignated. *Sierra Club* v. *EPA*, 99 F.3d at 1557–1558. The Clean Data Policy is simply an interpretation of certain provisions of the CAA, whose express purpose is to achieve attainment of the standard, as not requiring SIP revisions to be made by the State for so long as the area continues to attain the standard. The policy does not purport to exempt areas from requirements that are inapplicable only if an area is redesignated to attainment. It interprets certain provisions which are written in such a way as to impose requirements only upon areas that are not attaining the NAAQS, regardless of whether they have been redesignated to attainment. The EPA has not provided for any waiver from statutory requirements that was not provided by Congress. The area at issue remains designated nonattainment, and is subject to the risk that if a violation occurs it will have to

adopt and implement reasonable further progress requirements, contingency measures, and an attainment demonstration, unless it is redesignated to attainment. In order to be redesignated to attainment, however, the area will have to satisfy all of the requirements of section 107(d)(3)(E), including the requirement for a long-term maintenance plan.

While a determination of attainment is not equivalent to a redesignation to attainment, nothing in the Act compels EPA to wait until an area meets all the requirements for redesignation before EPA makes a determination that the area is in attainment with the standard, thereby suspending the requirements for certain provisions related to attainment. Indeed, section 179(c) of the Act requires EPA to make an attainment determination within six months after an area's applicable attainment date whether or not the EPA has made a finding with respect to redesignation. The EPA's interpretation of the Act's provisions not to require, once attainment has been reached, certain plan submissions whose purpose is to assure attainment, is not at odds with the requirements for redesignation. Nor does EPA's construction of the statute adversely impact planning for maintenance. An area that is monitoring attainment, but is still designated as a nonattainment area, retains strong incentives to seek redesignation to attainment, and remains subject to the requirement to demonstrate maintenance in order to be redesignated. For a detailed discussion of the relationship of redesignation requirements and attainment determinations, see the discussions in the EPA briefs in *Our Children's Earth Foundation* v. *EPA*, supra at pp. 43–60., *Sierra Club* v. *EPA* No. 95–9541 (10th Cir.) at 29–43, and *Sierra Club* v. *EPA* Nos. 03–2839, 03–3329 (7th Cir.) at 33–44 which are contained in the docket for this rulemaking.

Comment: A commenter noted that EPA's proposal suggested that areas attaining the standard would be subject to reduced regulatory requirements. The commenter believed that EPA's interpretation should be codified in regulatory form, in order to assure that areas legally meeting the current $PM_{2.5}$ standard and those requesting redesignation be enabled to be redesignated and to benefit from the interpretation through regulation, rather than by guidance or policy.

Response: The EPA has adopted the commenter's suggested approach of codifying its Clean Data Policy interpretation for $PM_{2.5}$ in regulatory form. Section 51.1004(c). As it did for ozone in its Phase II Ozone Implementation Rule, EPA is including in this rulemaking a regulation that encapsulates the statutory interpretation that is embodied in its Clean Data Policy for $PM_{2.5}$, set forth above. As noted in the response to comment above, determinations as to whether individual areas have attained the $PM_{2.5}$ standard and thus qualify for application of the rule will be made in the context of rulemakings for those individual areas. The EPA believes, however, that encapsulating its interpretation in regulatory form will lend clarity and consistency to the process of applying its interpretation.

E. Modeling and Attainment Demonstrations

1. Background

[Section III.F.1 of November 1, 2005 proposed rule (70 FR 66007); sec 51.1007 in draft and final regulatory text]

As noted in the proposal, Section 172(c) requires States with nonattainment areas to submit an attainment demonstration. An attainment demonstration consists of: (1) Technical analyses that locate, identify, and quantify sources of emissions that are contributing to violations of the $PM_{2.5}$ NAAQS; (2) analyses of future year emissions reductions and air quality improvement resulting from already-adopted national and local programs, and from potential new local measures to meet the RACT, RACM, and RFP requirements in the area; (3) adopted emission reduction measures with schedules for implementation; and (4) contingency measures required under section 172(c)(9) of the CAA.

a. Final Rule

The requirements from the proposal are unchanged. Each State with a nonattainment area will be required to submit a SIP with an attainment demonstration that includes analyses supporting the State's proposed attainment date. States must show that the area will attain the standards as expeditiously as practicable and it must include an analysis of whether implementation of reasonably available measures will advance the attainment date.

2. Areas That Need To Conduct Modeling

[Section III.F.2 of November 1, 2005 proposed rule (70 FR 66007)]

a. Background

All nonattainment areas need to submit an attainment demonstration, but in some cases, States may not need new, local-scale modeling analyses. In the proposed rule, EPA proposed that States may use in a $PM_{2.5}$ attainment demonstration certain local, regional and/or national modeling analyses that have been developed to support Federal or local emission reduction programs, provided the modeling meets the attainment modeling criteria set forth in EPA's modeling guidance. The proposal also stated that nonattainment areas for which local, regional, or national scale modeling demonstrates the area will not attain the standard within 5 years of designation would be required to submit an attainment demonstration SIP that includes new modeling showing attainment of the standards as expeditiously as practicable.

b. Final Rule

In the final rule, EPA is reaffirming the potential use of national and/or regional modeling as part of an attainment demonstration. We are also clarifying the types of modeling analyses that may be useful as a ''primary'' modeling analysis and as a ''supplemental'' analysis. The proposal suggested that it may be appropriate, in certain circumstances, for a State to submit regional or national modeling as the sole (primary) modeling analysis in its attainment demonstration. This implies that the State would not need to conduct local modeling analyses. We wish to further define the differences between ''national'', ''regional'', and ''local'' modeling analyses. In this context, national analyses are generally those conducted by EPA in support of national or regional rules. Regional and local modeling analyses are generally those conducted by the RPOs and/or States for the purpose of developing State Implementation Plans (SIPs). EPA has conducted national scale modeling for a variety of rules and analyses. Additionally, the RPOs and many States are conducting regional and/or local scale modeling of $PM_{2.5}$ and regional haze across the country. The national scale of the EPA modeling analyses requires basic assumptions concerning local model inputs. Compared to regional or local modeling done by the States and/or RPOs, EPA modeling may, in some cases, use coarser grid resolution, use inventories that are not as refined, and model performance may be highly variable from area to area. For these reasons, national scale modeling may not always be appropriate for local area attainment demonstrations.

Therefore, we believe that regional or local modeling conducted by the States or RPOs is best suited as the primary modeling analysis for a modeled

attainment demonstration. The local modeling is more likely to meet the recommendations contained in EPA's modeling guidance. However, some areas having design values close to the standard may be projected to come into attainment within five years based on modeling analyses of national and regional emission control measures (e.g. CAIR) that are scheduled to occur through 2009. Regional scale modeling for national rules such as the Tier II motor vehicle standards, the Heavy-duty Engine standards, the Nonroad Engine standards, and CAIR indicate major reductions in $PM_{2.5}$ by 2010. A portion of these benefits will occur in the 2006–2009 $PM_{2.5}$ attainment timeframe.

Experience with past ozone attainment demonstrations has shown that the process of performing detailed photochemical grid modeling to develop an attainment demonstration can be very resource intensive for States. The EPA believes that it would be appropriate for States to leverage resources by collaborating on modeling analyses to support SIP submittals, or by making use of recent modeling analyses that are completed prior to the SIP submittal date. For this reason, EPA recognizes that States may use in a $PM_{2.5}$ attainment demonstration certain local, regional and/or national modeling analyses that have been developed to support Federal or local emission reduction programs, provided the modeling meets the attainment modeling criteria set forth in EPA's modeling guidance (described below). As with all SIPs under subpart 1, the State must demonstrate that the area will attain the $PM_{2.5}$ standards as expeditiously as practicable. The judgment of whether the modeling is appropriate for an area should be made by the State(s) and their respective EPA regional office on a case-by-case basis.

c. Comments and Responses

Comment: There were many commenters that agreed that States should be able to use EPA modeling or other national or regional modeling as a modeled attainment demonstration. One commenter recommended that the final rule require States to show that the existing modeling incorporates realistic assumptions, accurately reflects local emissions and trends, and provides adequate model performance for the local nonattainment area.

Response: We agree that national and regional modeling may be used as part of an attainment demonstration as long as it is shown to be applicable to the local area. This is consistent with the proposal where we said that existing modeling should ''meet the attainment modeling criteria set forth in EPA's modeling guidance.'' Part of the analysis to determine if existing modeling meets the criteria in the modeling guidance is to assess whether the modeling incorporates realistic assumptions, accurately reflects local emissions and trends, and provides adequate model performance for the local nonattainment area.

Comment: Some commenters thought States should be able to use EPA modeling in the absence of an analysis of the applicability of the modeling for a local nonattainment area. One commenter said that EPA should determine that States should not have to do any additional modeling analyses if the CAIR modeling showed they were expected to attain the NAAQS by 2010.

Response: While we acknowledge there may be some circumstances in which national or regional modeling would be appropriate to use without local modeling and allow for such use, we disagree that national modeling should be used in support of an attainment demonstration without further analysis of the modeling assumptions for a particular area. National scale modeling may not always be appropriate for local areas. Most often, national scale EPA modeling is best suited for use as a supplemental analysis or as part of a ''weight of evidence'' demonstration. The modeling guidance recommends supplemental analyses for all attainment demonstrations. The guidance specifically recommends the examination of other modeling studies as a supplemental analysis. The EPA modeling as well as other ''non-local'' modeling can be used for this purpose. The ''weight'' of this alternative modeling in an attainment demonstration should be guided by how well the modeling system is suited for the local nonattainment area. States should consult with their EPA regional offices for further guidance and recommendations. As such, we do not believe it to be appropriate to determine a priori that CAIR or any other modeling analyses are appropriate to use in a local attainment demonstration for any or all nonattainment areas.

Comment: Several commenters believe that States should be able to use existing EPA modeling (such as CAIR), as the basis for an extension of the area's attainment date, if it shows that the nonattainment area may not be able to attain the NAAQS by 2010. They believe that the State should not have to do additional modeling to show that they need an attainment date extension.

Response: We disagree with this comment. The CAIR modeling included national controls that are expected to be in place by 2010 (including the CAIR rule itself), as well as existing state and local controls reflected in the inventory used in the CAIR analysis. It did not include any additional local controls that could be implemented under RACT and RACM requirements for the 1997 standards that may bring the area into attainment sooner. Nonattainment areas are required to attain the NAAQS as expeditiously as practicable. Therefore, updated modeling of existing controls as well as additional local controls is needed before an attainment date extension can be granted. Additional information on attainment dates and extensions is contained in the preamble to the final rule, section II.D., and additional information on RACT and RACM requirements is contained in section II.F.

Comment: Several commenters noted an apparent inconsistency in the language concerning who would be required to perform ''new'' local-scale modeling. First, there are potentially conflicting statements in the proposal when EPA states that areas with an attainment date of 2010 will need to conduct local-scale modeling to project the estimated level of air quality improvement in accordance with EPA's modeling guidance. This conflicts with the proposed ability for States to use existing national or regional modeling as their modeled attainment demonstration. Second, a portion of a sentence was removed from the **Federal Register** version of the notice which differs from the pre-**Federal Register** version. The published version implies that all nonattainment areas would be required to submit new modeling.

Response: We agree that there are inconsistencies in the proposal preamble text. To clarify, new local-scale modeling is required for areas that are not expected to come into attainment by 2010. For other areas, there may be national or regional modeling which may be applicable to the area which shows they are likely to come into attainment. As noted earlier, national scale modeling is best suited for use as a supplemental analysis, but in some cases may be acceptable evidence that an area will attain by 2010.

Additionally, the preamble language in the **Federal Register** contained an error. A portion of a sentence was mistakenly removed, which led to some confusion. The language in the FR notice (FR page 66008) stated ''Nonattainment areas would be required to submit an attainment demonstration SIP that includes new modeling showing attainment of the

standards as expeditiously as practicable. The new modeling will need to include additional emissions controls or measures in order to demonstrate attainment.'' The language should have read, ''Nonattainment areas *for which local, regional, or national scale modeling demonstrates the area will not be in attainment of the NAAQS within 5 years of designation* would be required to submit an attainment demonstration SIP that includes new modeling showing attainment of the standards as expeditiously as practicable. The new modeling will need to include additional emissions controls or measures in order to demonstrate attainment.'' This should clarify that States that cannot show attainment within 5 years will need to develop new modeling analyses which contain additional control strategies which show how and when they expect to attain the $PM_{2.5}$ NAAQS.

Comment: One commenter maintained that relying on large-scale regional modeling alone may allow for $PM_{2.5}$ hot spots (i.e. small unmonitored areas projected to exceed the standard) to exist past the attainment date.

Response: We agree that nonattainment areas with potential hotspot issues (relatively high concentrations and/or gradients of primary $PM_{2.5}$) should not rely exclusively on regional modeling. The EPA's attainment demonstration modeling guidance attempts to address several aspects of hotspot issues in both monitored and unmonitored areas [17]. The modeled attainment tests contained in EPA's modeling guidance are primarily monitor based tests. Ambient data is combined with the model predicted relative change in PM components to determine if attainment of the standards is likely in the future. There are several aspects of the attainment test. In most cases, States will run a photochemical grid model to determine the future year predicted $PM_{2.5}$ concentrations at monitors. The modeling guidance generally recommends that for urban scale $PM_{2.5}$ modeling, the State performs modeling analyses at 12 kilometer grid resolution or finer. There is an additional component to the attainment test for areas that have measured relatively high concentrations and/or gradients of primary $PM_{2.5}$ at monitors. In these cases, we recommend running a Gaussian dispersion model for potential primary PM sources, to determine the local impact of changes in primary PM emissions (from the modeled sources) on predicted concentrations at the monitor(s).

In addition, we describe an ''unmonitored area analysis'' which uses interpolated ambient data combined with gridded model outputs to examine whether potential violations of the NAAQS may occur in unmonitored areas. If potential violations are indicated, we recommend further analysis of the problem through additional local modeling. Options for State action to address such a situation could include imposition of reasonably available control technology to reduce emissions, or the deployment of an air quality monitor to further characterize the problem.

We believe that the combination of these model-based tests will adequately determine whether attainment of the standards is likely by the attainment date. We also believe that these tests address the issue of hotspots by recommending a combination of photochemical modeling, dispersion modeling of local sources, and additional monitoring and/or emissions controls.

3. Modeling Guidance

[Section III.F.3 of November 1, 2005 proposed rule (70 FR 66008)]

a. Background

Section 110(a)(2)(K)(i) states that SIPs must contain air quality modeling as prescribed by the Administrator for the purpose of predicting the effect of emissions on ambient air quality. The procedures for modeling $PM_{2.5}$ as part of an attainment SIP are contained in EPA's ''Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze.'' The proposal summarized several of the chapters in a draft version of the modeling guidance.

b. Final Rule

A draft of the $PM_{2.5}$ attainment demonstration and regional haze modeling guidance has now been revised (September 2006) and is available at *http://www.epa.gov/ttn/scram/guidance_sip.htm*. The draft $PM_{2.5}$ attainment demonstration and regional haze guidance has been incorporated into the ozone modeling guidance and is now called ''Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for the 8-Hour Ozone and $PM_{2.5}$ NAAQS and Regional Haze''. The final version of the modeling guidance will be available at the same location in the near future.

The revised draft $PM_{2.5}$ modeling guidance document is very similar to the previous draft version, although there were several changes and updates. Among them are new methods in treating $PM_{2.5}$ species components as part of the $PM_{2.5}$ attainment test; new methods for determining potential future year violations in unmonitored areas; new procedures for handling potential $PM_{2.5}$ ''hotspots''; and an increased reliance on supplemental analyses, including ''weight of evidence'' analyses. The EPA notes that the $PM_{2.5}$ attainment demonstration modeling guidance that we have released is separate from the Agency's future hot-spot modeling guidance for transportation conformity purposes.[18]

The modeling guidance describes how to estimate whether a control strategy to reduce emissions of particulate matter and its precursors will lead to attainment of the annual and 24-hour $PM_{2.5}$ NAAQS. Part I of the guidance describes a ''modeled attainment test'' for the annual and 24-hour $PM_{2.5}$ NAAQS. Both tests are similar. The output of each is an estimated future design value consistent with the respective forms of the NAAQS. If the future design value does not exceed the concentration of $PM_{2.5}$ specified in the NAAQS, then the primary modeled test is passed. The modeled attainment test applies to locations with monitored data.

A separate test is recommended to examine projected future year $PM_{2.5}$ concentrations in unmonitored locations.[19] Interpolated $PM_{2.5}$ ambient data, combined with modeling data, is used to predict $PM_{2.5}$ concentrations in unmonitored areas. The goal of this analysis is to identify areas without monitors that may be violating the $PM_{2.5}$ NAAQS, often due to high levels of primary $PM_{2.5}$ (both now and in the future). The details of the analysis are contained in the final modeling guidance.

The guidance also discusses modeling $PM_{2.5}$ at monitors where high concentrations of primary $PM_{2.5}$ are measured. In these cases, it may be beneficial to model the primary component of the $PM_{2.5}$ with a Gaussian dispersion model. Dispersion models are better able to capture the influence

[17] The recommendations contained in the modeled attainment demonstration guidance are separate from the Agency's future hot-spot modeling guidance for transportation conformity purposes.

[18] In the March 10, 2006, final transportation conformity rule (71 FR 12468), EPA committed to develop $PM_{2.5}$ and PM_{10} quantitative hot-spot modeling guidance for transportation conformity determinations for highway and transit projects of local air quality concern.

[19] Application of the unmonitored area analysis is limited to locations which are appropriate to allow the comparison of predicted $PM_{2.5}$ concentrations to the NAAQS, based on $PM_{2.5}$ monitor siting requirements and recommendations.

of primary PM sources where large concentration gradients may exist. Grid models spread out the PM emissions to the size of the grid (typically 4 or 12 km). This makes it difficult to judge the benefits of control strategies that may affect primary PM sources. The final modeling guidance recommends procedures for applying dispersion models in these situations.

The guidance also recommends the submittal of supplemental analyses as part of all attainment demonstrations. Supplemental analyses are modeling, emissions, and/or ambient data analyses that are submitted as part of a SIP, in addition to the primary modeled attainment test. The evaluation of supplemental analyses when the predicted concentrations in the primary attainment test are close to the NAAQS (slightly above or slightly below) is called a weight-of-evidence (WOE) analysis. This is simply a collection of evidence that aims to show that attainment of the standard is likely. The final version of the modeling guidance puts more emphasis on the submittal of supplemental analyses than in previous versions.

Part II of the guidance describes how to apply air quality models to generate results needed by the modeled tests for attainment. This includes developing a conceptual description of the problem to be addressed; developing a modeling/analysis protocol; selecting an appropriate model to support the demonstration; selecting appropriate meteorological episodes or time periods to model; choosing an appropriate area to model with appropriate horizontal/vertical resolution; generating meteorological and air quality inputs to the air quality model; generating emissions inputs to the air quality model; evaluating performance of the air quality model; and performing diagnostic tests. After these steps are completed, the model is used to simulate the effects of candidate control strategies.

Comment: Several commenters were supportive of the weight of evidence concept. They said that $PM_{2.5}$ modeling is inherently more uncertain than previous ozone modeling and the modeling guidance should reflect that. One commenter noted that weight of evidence demonstrations should be ''unbiased'', meaning that States should use all relevant analyses and not only information that helps their case.

Response: The EPA agrees with these comments. The final modeling guidance recommends supplemental analyses (including weight of evidence) for all attainment demonstrations. All States should submit modeling, ambient data, and emissions analyses in addition to the primary modeling demonstration. A weight of evidence analysis is needed if the predicted future year $PM_{2.5}$ concentrations are slightly higher or slightly lower than the NAAQS.

We also agree that a weight of evidence demonstration should include all relevant information, including analyses which support attainment and those that do not. The idea of the analysis is to ''weigh'' the evidence, both good and bad. That cannot be fairly done if some evidence is not presented.

Comment: Several commenters suggested that a modeled attainment demonstration should not be specifically required. Instead they suggest that all demonstrations should be weight of evidence demonstrations. This would include different analyses of ambient data, trends, and modeling. But due to the uncertainties in the current $PM_{2.5}$ models and emissions data, modeling would be but one part of a broader weight of evidence approach.

Response: We disagree with this comment. Model results should be the primary analysis of an attainment demonstration. Regardless of current uncertainties in the $PM_{2.5}$ models and emissions, models are the only tool that can predict future concentrations of $PM_{2.5}$. The uncertainties in the model inputs and formulation should be taken into account when evaluating the results. We agree that a broad analysis of modeling, ambient data and emissions trends should be part of the attainment demonstration. This is reflected in the final modeling guidance.

4. Modeled Attainment Test

[Section III.F.4 of November 1, 2005 proposed rule (70 FR 66008)]

a. Background

The proposal described the nature of the attainment tests for the annual average and 24-hour average $PM_{2.5}$ NAAQS contained within the modeling guidance. Both tests use monitored data to estimate current air quality. The attainment test for a given standard is applied at each monitor location within or near a designated nonattainment area for that standard. There is also an additional attainment test to be performed in unmonitored areas. Models are used in a relative sense to estimate the response of measured air quality to future changes in emissions. Future air quality is estimated by multiplying current monitored values times modeled responses to changes in emissions. Because $PM_{2.5}$ is a mixture of chemical components, the guidance recommends using current observations and modeled responses of major components of $PM_{2.5}$ to estimate future concentrations of each component. The predicted future concentration of $PM_{2.5}$ is the sum of the predicted component concentrations.

b. Final Rule

The nature of the $PM_{2.5}$ attainment tests is unchanged. The final modeling guidance recommends refinements to the test and discusses the treatment of individual $PM_{2.5}$ species. The speciated modeled attainment test (SMAT) that was used to estimate future $PM_{2.5}$ concentrations for CAIR has been (mostly) implemented in the final guidance. Among the new recommendations is to better account for the known differences between the $PM_{2.5}$ Federal Reference Method (FRM) measurements and the $PM_{2.5}$ speciation measurements. For example, it is recommended to account for the volatilization of nitrate from the FRM filters and to account for uncertainties in organic carbon measurements by employing an ''organic carbon by mass balance'' technique. This assumes that all remaining mass not accounted for by other species is organic carbon mass. Additional details are contained in the modeling guidance.

The guidance also recommends, where necessary, to spatially interpolate $PM_{2.5}$ species data to estimate the species concentrations at FRM sites. It is necessary to estimate species concentrations when there are no species measurements at FRM sites. Several techniques can be used to estimate species concentrations. Spatial interpolation techniques may be useful in many areas. In other cases, it may be adequate to assume that data from a speciation monitor may be representative of multiple FRM monitors. It is particularly important to develop credible techniques to estimate species concentrations at the locations of the highest FRM monitors.

The guidance lists several techniques that can be used. The EPA will provide software which will apply the modeled attainment test, using ambient data and model outputs. Additionally, the software will interpolate the $PM_{2.5}$ species data to allow application of SMAT for all FRM monitors. The software will be available at the same location as the final modeling guidance (*http://www.epa.gov/scram001/guidance_sip.htm*).

Ultimately, it is up to the States to determine the best method to represent the $PM_{2.5}$ species concentrations, subject to EPA's review and approval. These estimates are needed to perform the modeled attainment test.

c. Comments and Responses

Comment: Several commenters were concerned that interpolation of $PM_{2.5}$ species concentrations may not be appropriate in certain areas or situations. The concentrations can vary significantly between urban and rural areas and even between nearby urban areas. One commenter suggested that it might be useful to use older field study measurements to derive current species concentrations. Another commenter suggested that it might be reasonable to assume that speciation measurements were representative of nearby FRM sites.

Response: We agree that interpolations of species data may not always be the best way to estimate species concentrations at FRM sites. The modeling guidance lists several different possible techniques. States should review their data and situation and choose the most reasonable methodology to estimate species concentrations. Nonattainment areas that don't have speciation measurements at the highest FRM site(s) need to be especially careful. The result of the speciated attainment test can be heavily influenced by the assumed species concentrations at the highest FRM sites. The attainment test will be more straightforward in areas with speciation monitors at the highest FRM sites. States are also encouraged to place speciation monitors at the highest FRM sites. This will aid in future assessments of attainment and ambient trends.

5. Multi-Pollutant Assessments

[Section III.F.5 of November 1, 2005 proposed rule (70 FR 66009)]

a. Background

The formation and transport of $PM_{2.5}$ is in many cases closely related to the formation of both regional haze and ozone. There is often a positive correlation between measured ozone and secondary particulate matter. Many of the same factors affecting concentrations of ozone also affect concentrations of secondary particulate matter. For example, similarities exist in sources of precursors for ozone and secondary particulate matter. Emissions of NO_X may lead to formation of nitrates as well as ozone. Sources of VOC may be sources or precursors for both ozone and organic particles. Presence of ozone itself may be an important factor affecting secondary particulate formation. The proposal recommended multi-pollutant assessments for $PM_{2.5}$ attainment demonstrations. A multi-pollutant assessment, or one-atmosphere modeling, is conducted with a single air quality model that is capable of simulating transport and formation of multiple pollutants simultaneously. This type of model simulates the formation and deposition of $PM_{2.5}$, ozone, and regional haze components, and it includes algorithms simulating gas phase chemistry, aqueous phase chemistry, aerosol formation, and acid deposition.

b. Final Rule

The recommendation to conduct multi-pollutant assessments remains unchanged. It is recommended to model the impacts of future year control strategies on $PM_{2.5}$, ozone, and regional haze. It may not always be possible or convenient to do so, but it can be beneficial to the strategy development process.

$PM_{2.5}$ control strategies will have an impact on regional haze, and will possibly impact ozone. Even if high ozone and high $PM_{2.5}$ concentrations don't typically occur during the same time of the year, controls that affect precursors to $PM_{2.5}$ may also affect ozone (e.g. NO_X). The SIP submittal dates for $PM_{2.5}$, ozone, and regional haze do not currently line up. The $PM_{2.5}$ SIPs are due almost 1 year later than ozone. But States can still do modeling analyses that can provide information for multiple pollutants. States can use one-atmosphere models that are capable of simulating both ozone and $PM_{2.5}$. They can also try to use consistent meteorological fields and emissions inventories so that the same control strategies are relatively easy to evaluate for both ozone and $PM_{2.5}$. Modeling the same future year(s) for $PM_{2.5}$ and ozone can also make it easier to evaluate the impacts of controls on both pollutants.

It should be noted that there are no specific modeling requirements other than the recommendation to try to harmonize the ozone, $PM_{2.5}$, and regional haze analyses whenever possible.

c. Comments and Responses

Comment: One commenter suggests that multi-pollutant assessments may not be beneficial because their area experiences winter $PM_{2.5}$ exceedances and summer ozone exceedances.

Response: We disagree with the comment. Even in situations where high $PM_{2.5}$ and ozone don't occur during the same time of year, multi-pollutant assessments may be helpful. NO_X controls that may be needed to reduce nitrates in the winter are likely to have an impact on ozone in the summer. As well, changes in VOCs may have an impact on both $PM_{2.5}$ and ozone. Running potential control strategies through the same modeling platform for ozone, $PM_{2.5}$, and regional haze may allow the development of optimized strategies.

6. Which Future Year(s) Should Be Modeled?

[Section III.F.6 of November 1, 2005 proposed rule (70 FR 66009)]

a. Background

Modeling analyses consist of base year modeling and future year modeling. The attainment test examines the change in air quality between the base and future years. The proposal recommended, where possible, future modeling years should be coordinated so that a single year can be used for both $PM_{2.5}$ and ozone modeling. This coordination will help to reduce resources expended for individual modeling applications for $PM_{2.5}$ and ozone and will facilitate simultaneous evaluation of ozone and PM impacts.

Although there is some flexibility in choosing the future year modeling time periods, unless the State believes it cannot attain the standards within 5 years of the date of designation and must request an attainment date extension, the choice of modeling years for $PM_{2.5}$ cannot go beyond the initial 5 attainment period. Attainment date extensions will only be granted under certain circumstances. Among other things, the State must submit an attainment demonstration showing that attainment within 5 years of the designation date is impracticable.

b. Final Rule

Further information is now known concerning the modeling years for ozone. Moderate nonattainment areas are presumed to be modeling 2009. This is consistent with the last year of the 5 year period allowed under Subpart I for $PM_{2.5}$. Therefore, it is logical to presume that areas that are able to attain the $PM_{2.5}$ NAAQS within 5 years will model a future year of 2009. Areas that won't be able to attain the standard in 5 years will need to request an attainment date extension (of up to 5 additional years).

The NAAQS must be attained as expeditiously as practicable. Therefore, attainment date extensions must contain modeling analyses to justify the extension. Details of the required analyses are contained in the RACT and RACM sections of the final rule. See section F for more details.

F. Reasonably Available Control Technology and Reasonably Available Control Measures

This section of the preamble discusses the final rule requirements for RACT and RACM. In order to explain EPA's

approach in the final rule more clearly, we first discuss the statutory and regulatory background for the RACT and RACM requirements, and we then explain the key options and interpretations upon which we took comment in the proposal. Thereafter, we discuss significant comments we received on the proposal and provide brief responses to those comments. [Additional comments and responses appear in the RTC for this final rule located in the docket.] Most of the comments received on this topic addressed the three options EPA proposed for the RACT requirement, the relationship between the RACT requirement and EPA's Clean Air Interstate Rule (CAIR), and the control measures to be required or considered for RACT and RACM.

1. Background on Statutory Requirements for RACT and RACM

Subpart 1 of Part D of the CAA (sections 171–179B) applies to all designated nonattainment areas. Section 172 of this subpart includes general requirements for all attainment plans.

Notably, Congress provided EPA and States a great deal of deference for determining what measures to include in an attainment plan. Specifically, Section 172(c)(1) requires that each attainment plan ''provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology), and shall provide for attainment of the national primary ambient air quality standards.'' By including language in Section 172(c)(1) that only ''reasonably available'' measures be considered for RACT/RACM, and that implementation of these measures need be applied only ''as expeditiously as practicable,'' Congress clearly intended that the RACT/RACM requirement be driven by an overall requirement that the measure be ''reasonable.'' Thus, the rule of ''reason'' drives the decisions on what controls to apply, what should be controlled, by when emissions must be reduced, and finally, the rigor required in a State's RACT/RACM analysis. For example, we previously stated that the Act ''does not require measures that are absurd, unenforceable, or impractical'' or result in ''severely disruptive socioeconomic impacts'' 55 FR 38327. Moreover, we interpret the term ''reasonably available'' to allow States to consider both the costs and benefits of applying the measure, and whether the measure can be readily and effectively implemented without undue administrative burden. 66 FR 26969.

We also interpret the ''reasonably available control measures'' in these provisions as referring to measures of any type that may be applicable to a wide range of sources, whereas the parenthetical reference to ''reasonably available control technology'' refers to measures applicable to stationary sources. RACM can apply to mobile sources, areas sources and stationary sources not already subject to $PM_{2.5}$ RACT requirements. Thus, RACT is a type of RACM specifically designed for stationary sources. As noted above, States are required to implement RACM and RACT ''as expeditiously as practicable'' as part of attainment plans designed to attain the standards.[20]

Section 172 does not include any specific applicability thresholds to identify the size of sources that States and EPA must consider in the RACT and RACM analysis. Nor, does Section 172 specifically indicate which pollutant(s) or precursor(s) must be subject to RACM or RACT measures to attain the NAAQS. Other pollutant-specific provisions of the CAA do include applicability thresholds pertaining to attainment plan requirements for NAAQS and precursor pollutants. For example, subpart 2 of part D, which establishes additional requirements for ozone nonattainment areas, establishes thresholds ranging from 100 to 10 tons per year for requirements applicable to ''major sources'' or ''major stationary sources,'' depending on the area's classification or level of nonattainment. Subpart 4 of part D, which provides additional plan requirements for PM_{10} nonattainment areas, establishes thresholds of 100 and 70 tons per year for requirements applicable to a ''major source'' or ''major stationary source.''

Moreover, subpart 1, unlike subparts 2 and 4, does not identify specific source categories for which EPA must issue control technology documents or guidelines, or identify specific source categories for State and EPA evaluation during attainment plan development. For ozone, subpart 2 contains a list of specific requirements for control techniques guidelines (CTGs) and alternative control techniques (ACT) documents. For PM_{10}, section 190 of the CAA (in subpart 4) places particular emphasis on specific sources of area emissions, but does not identify specific stationary source categories for which RACT guidance must be issued. Section 190 requires EPA to develop RACM guidance documents for residential wood combustion, silvacultural and agricultural burning, and for urban fugitive dust control.

2. What Is the Overall Approach To Implementing RACT and RACM in the Final Rule?

a. Background for RACT

Since the 1970s, EPA has interpreted RACT to mean ''the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' as well as other considerations.[21] Presumptive RACT has been described as the norm achievable by the source category.[22]

Section 110 of the 1970 Clean Air Act required States to develop SIPs providing for attainment of the NAAQS by 1975 or 1977. A number of areas were having difficulty with developing attainment plans, particularly for the ozone standard. In response to the implementation needs of this time period, EPA introduced the term ''RACT'' in a 1976 memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management to Regional Administrators, ''Guidance for Determining Acceptability of SIP Regulations in Non-attainment Areas'' (Dec. 9, 1976). In this early guidance relating to the acceptability of SIP regulations, we indicated that our overriding concern in approving SIPs was attaining the particular NAAQS as expeditiously as practicable through reasonably available control technology and other reasonably available control measures. ''The basis for fully approving state-submitted SIP regulations continues to be demonstrated attainment and maintenance of all national ambient air quality standards as expeditiously as practicable,'' the memo stated.

The 1977 Clean Air Act amendments added Part D to Title I of the Act, and for the first time the Act specifically called for EPA to designate nonattainment areas and for SIPs to require RACT and RACM in those nonattainment areas. In a 1979 **Federal**

[20] Under the Tribal Air Rule (TAR), requirements for RACT and RACM may be considered to be severable elements of implementation plan requirements for Tribes.

[21] See, 44 FR 53782, September 17, 1979, and 1976 memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management to Regional Administrators, ''Guidance for Determining Acceptability of SIP Regulations in Non-attainment Areas'' (Dec. 9, 1976).

[22] See e.g. Workshop on Requirements for Non-attainment Area Plans—Compilation of Presentations (OAQPS No. 1.2–103, revised edition April 1978).

Register notice, EPA noted its view that Congress adopted EPA's pre-existing conception of RACT in the 1977 amendments. (44 FR 53782, September 17, 1979). Also during the late 1970s, EPA developed a number of new control techniques guideline (CTG) documents as directed in the 1977 amendments. These CTGs provided States with information on controls for a number of categories of sources emitting VOCs, and recommended a ''presumptive norm'' for State RACT determinations based on the control levels achievable by sources in a given industry. CTGs reduced the burden on States by eliminating the need for each State to develop its own technical support for implementing the RACT requirement. Since the CTG-recommended controls were based on general capabilities of an industry, EPA in the 1979 guidance (44 FR 53782) urged States in setting RACT to judge the feasibility of the recommended controls on particular sources, and to adjust accordingly.

As noted above, EPA's early guidance related to the RACT requirement indicated that our overriding concern in approving State RACT requirements was attaining the particular NAAQS. We initially required States to apply RACT to qualify for attainment extensions, and in some cases, for plans that could not demonstrate attainment.

During the 1980s, EPA implemented the RACT requirements with a number of CTGs and guidance documents. These materials were aimed at addressing the attainment deadlines of 1982 and 1987 under the 1977 Clean Air Act amendments. During this time, EPA, for pollutants other than ozone, considered RACT to be dependent upon reductions needed for attainment as expeditiously as practicable. For ozone, where the State performed photochemical grid modeling, the approach was the same, but where the State used less sophisticated tools, we considered RACT to be independent of whether the controls were needed to reach attainment as expeditiously as practicable. We took this alternate approach because of concerns related to the precision of modeling techniques. In other words, in those cases, we required that a stationary source of the requisite type and size be subject to RACT, whether or not such controls were actually demonstrated to be necessary for the area to attain by its specified date. (44 FR 20375–20376, April 4, 1979)

Congress followed a similar approach in the 1990 amendments to the CAA for purposes of the ozone NAAQS in the subpart 2 provisions added at that time. For example, section 182(b)(2) requires the imposition of RACT controls for all VOC source categories covered by a CTG and for all other major stationary sources of VOC located within certain nonattainment areas. Thus, Congress required these controls without allowing for an area-specific demonstration by the State that the area needed the controls for attainment as expeditiously as practicable. Extensive discussion of this requirement appeared in the 1992 general preamble (57 FR 13541), in which EPA provided guidance for implementation of the ozone NAAQS.

Notably, Congress did not significantly amend the generally applicable provisions for nonattainment areas that appear in subpart 1 of Part D in 1990. This indicates that Congress intended that the Agency retain the authority to interpret the generally applicable nonattainment area plan requirements of section 172(c), including the RACT and RACM requirements, in the way that is most appropriate for new NAAQS that are subject to subpart 1. As discussed below, EPA has determined that an approach to the RACT requirement in which RACT varies in different nonattainment areas based on the reductions needed for attainment as expeditiously as practicable, is appropriate for implementation of the $PM_{2.5}$ NAAQS. We believe that the improved ability to model air quality impacts of emissions controls allows for this approach.

b. Proposed Options for RACT

The EPA proposed and requested comment on three alternative approaches for interpretation of the RACT requirement of section 172(c)(1) for implementation of the $PM_{2.5}$ NAAQS. The EPA proposed these approaches in order to evaluate which method would best ensure that States consider and adopt RACT measures for stationary sources in a way that is consistent with the overarching requirement to attain the standards as expeditiously as practicable, while providing flexibility for States to focus regulatory resources on those sources of emissions that contribute most to local $PM_{2.5}$ nonattainment.

Under the first proposed alternative, EPA would require States to conduct a RACT analysis and to identify and require reasonably available controls for all affected stationary sources in the nonattainment area, comparable to the implementation of RACT provided in subpart 2 governing implementation of the 1-hour ozone NAAQS. Under this option, covered sources would be required to apply reasonable available controls considering technical and economic feasibility, and there would be no opportunity for States to excuse stationary sources from control on the basis that the emissions reductions from those controls would not be necessary to meet RFP requirements or to reach attainment. Under this alternative, EPA proposed to limit the universe of sources for which States must conduct a RACT analysis and impose RACT controls, by providing an applicability threshold based upon the amount of emissions potentially emitted by the sources. Under this first option, EPA requested comment on a number of alternative emissions applicability thresholds.

Under the second proposed alternative, EPA would require States to conduct a RACT analysis and to identify reasonably available controls for all affected stationary sources. Under this option, however, States could thereafter determine that RACT does not include controls that would not otherwise be necessary to meet RFP requirements or to attain the $PM_{2.5}$ NAAQS as expeditiously as practicable.[23] Under this approach, RACT would be determined as part of the broader RACM analysis and identification of all measures—for stationary, mobile, and area sources—that are technically and economically feasible, and that would collectively contribute to advancing the attainment date.[24] Because RACT and RACM are considered together under this alternative, we did not propose emissions threshold options for evaluation of stationary source RACT. In addition, consistent with existing policies, States would be required to evaluate the combined effect of reasonably available measures to determine whether application of such measures could advance the attainment date by at least one year.[25]

The third proposed alternative, EPA's preferred option in the proposal, combined the first two options and is similar to the RACT approach adopted in the final implementation rule for the 8-hour ozone program. Under the third option, EPA would require States to conduct a RACT analysis and to require reasonably available controls for all affected stationary sources in

[23] Under the Tribal Air Rule (TAR), requirements for RACT and RACM may be considered to be severable elements of implementation plan requirements for Tribes.

[24] In *Sierra Club* v. *EPA*, 294 F.3d 155 (D.C. Cir. 2002), the court stated in upholding EPA's statutory interpretation of RACM that the Act does not compel a state to consider a measure without regard to whether it would expedite attainment.

[25] In this notice, where we use the shorthand phrase ''advance the attainment date,'' it means ''advance the attainment date by one year or more.''

nonattainment areas with attainment dates more than 5 years from the date of designation. For areas with an attainment date within 5 years of designation (e.g. by April 5, 2010 for areas with an effective date for designation of April 5, 2005), EPA would require RACT as under the second proposed alternative, in which RACT would be determined as part of the broader RACM analysis. For these areas, States could determine that RACT does not include controls that would not otherwise be necessary to meet RFP requirements or to attain the $PM_{2.5}$ NAAQS as expeditiously as practicable. The same proposed suboptions with respect to the size of sources for consideration under the first alternative were also included under this alternative.

c. Proposed Approach for RACM

The EPA proposed and asked for comment on one approach for interpreting the RACM requirement for $PM_{2.5}$. The EPA based the proposal on the approach that we adopted for other NAAQS implementation programs. Under this approach, a State provides a demonstration in its SIP that it adopted all reasonably available measures needed to meet RFP requirements and to attain the standard as expeditiously as practicable and that no reasonably available additional measures would advance the advance the attainment date by at least 1 year or would be necessary to meet the RFP requirement for the area.[26]

Under section 172(a)(2), the state implementation plan must provide for a nonattainment area to attain as expeditiously as practicable, but no later than 5 years after the effective date of designation of the area (e.g., no later than April 2010 for the final designations effective April 2005). The statute thus creates a presumption for attainment within 5 years of designation unless certain statutory criteria are met for an extension of the attainment date. Under the proposed approach to RACM for $PM_{2.5}$, each State would evaluate available measures for sources of $PM_{2.5}$ or its regulatory precursors in the area to determine if reasonable measures were needed to meet the RFP requirement or to achieve attainment as expeditiously as practicable. If modeling of all RACM and other state, regional and federal measures indicates that the State will not be able to demonstrate attainment within 5 years after designation based upon the severity of nonattainment in that area or the availability or feasibility of implementing controls in that area, then the State may request an attainment date extension. We proposed that under these circumstances, the EPA could extend the attainment date for a period of 1 to 5 years, when the State shows that it will implement all RACT and RACM as expeditiously as practicable, has met its obligation to address intrastate pollution transport from sources within its jurisdiction, and still needs additional time to attain.

In the proposed rule, the EPA also took comment on the following overall steps for implementing the statutory requirement for RACM.

(1) *Identification of measures.* The State would begin the process of determining RACM by identifying all available control measures for all sources of $PM_{2.5}$ and its precursors in the nonattainment area. The RACM can apply to mobile sources, area sources, and stationary sources.

(2) *Evaluation of measures.* After the State identifies the universe of available measures for the sources in the area, the State would evaluate them to determine whether implementation of such measures is technically and economically feasible, and whether the measure will contribute to advancing the attainment date.

(3) *Adoption of measures.* The State would adopt all reasonably available measures for the area consistent with meeting the applicable RFP requirements and attaining the NAAQS as expeditiously as practicable, in accordance with applicable policy and guidance for attainment demonstrations. We would then approve or disapprove the State's plan through notice and comment rulemaking. We also noted that in reviewing the State's selection of measures for RACM, or determining that certain measures are not RACM, EPA may independently supplement the rationale of the State or provide an alternative reason for reaching the same conclusion as the State.

c. Final Rule

The EPA carefully considered our interpretation of section 172(c)(1) for the $PM_{2.5}$ NAAQS. Because of the variable nature of the $PM_{2.5}$ problem in different nonattainment areas, which may require States to develop attainment plans that address widely disparate circumstances (e.g., different source types and mixes, different precursors and mixes of precursors, and different meteorological conditions), we determined that the regulations implementing the $PM_{2.5}$ NAAQS should provide for a great degree of flexibility with respect to the RACT and RACM controls.

Selected approach to RACT and RACM. The final rule reflects EPA's decision to select option 2 for RACT and to require a combined approach to RACT and RACM. Under this approach, RACT and RACM are those measures that a State finds are both reasonably available and contribute to attainment as expeditiously as practical in the specific nonattainment area.

By definition, measures that are not necessary either to meet the RFP requirement, or to help the area attain the NAAQS as expeditiously as practicable, are not required RACT or RACM for such area. The EPA believes that this approach provides the greatest flexibility to a State to tailor its SIP control strategy to the needs of a particular $PM_{2.5}$ nonattainment area, but it may require the State to conduct a more detailed analysis to identify the most effective RACT/RACM strategy to attain the NAAQS.

During the comment period, commenters raised concerns that this approach may be overly burdensome on States because of the number of potential control measures a State would need to consider. Today, we clarify that although the State must conduct a thorough analysis of reasonably available measures, States need not analyze every conceivable measure, as explained in the guidance below. Instead, ''reason'' should drive States identification of potential measures, but States should remain mindful of the public health risks of $PM_{2.5}$. As long as a State's analysis is sufficiently robust in considering potential measures to ensure selection of all appropriate RACT and RACM, and the State provides a reasoned justification for its analytical approach, we will consider approving that State's RACT/RACM strategy.

Guidance on State analysis to identify RACT, RACM and appropriate attainment date. A State must consider RACT and RACM for all of its nonattainment areas. However, EPA believes that if the State projects that an area will attain the standard within 5 years of designation as a result of existing national measures (i.e. projected to have a design value of 14.5 or lower), then the State may conduct a limited RACT and RACM analysis that does not involve additional air quality modeling. A limited analysis of this type would involve the review of reasonably available measures, the estimation of potential emissions

[26] In the context of the PM_{10} NAAQS, EPA has concluded that ''advancement of the attainment date'' should mean an advancement of at least one calendar year. *See* State Implementation Plans; General Preamble for the Implementation of Title I of the CAA Amendments of 1990, 57 FR 12498 (April 16, 1992). *See also Sierra Club* v. *EPA,* 294 F.3d 155 (D.C. Cir. 2002).

reductions, and the evaluation of the time needed to implement these measures. If the State could not achieve significant emissions reductions during 2008 due to time needed to implement the potential measures or other relevant factors, then the State and EPA could conclude that there are no further reasonably available control measures for that area that would advance the attainment date by one year or more relative to the presumptive outer limit for attainment dates, i.e., 5 years from designation. In lieu of conducting air quality modeling to assess the impact of potential RACT and RACM measures, States may consider existing modeling information to determine the magnitude of emissions reductions that could significantly affect air quality and potentially result in attaining prior to 2010 (e.g. in 2009 based on 2006–8 air quality data). If the State, in consultation with EPA, determines from this initial, limited RACT and RACM analysis that the area may be able to advance its attainment date through implementation of reasonable measures, then the State would conduct a more detailed RACT and RACM analysis, including appropriate air quality modeling analyses, to assess whether it can advance the attainment date.

In general, the combined approach to RACT and RACM in the final rule includes the following steps: (1) Identification of potential measures that are reasonable; (2) modeling to identify the attainment date that is as expeditious as practicable; and (3) selection of RACT and RACM.

Identification of potential measures. The State's review of potential measures must be sufficient to identify all appropriate RACT and RACM. As stated previously, inherent to RACT/RACM is the basic requirement that the measure be ''reasonable.'' A State need not evaluate measures in its RACM/RACT analysis that it determines are unreasonable such as measures that are ''absurd, unenforceable, or impractical'' or that would cause ''severely disruptive socioeconomic impacts, (e.g. gas rationing and mandatory source shutdowns); such measures are not required by the Act. 55 FR 38327.

As we also stated earlier, a State's RACT/RACM analysis not only involves an assessment about what emissions sources to control and to what level, but also a judgment as to when it is reasonable to require a sector to comply with a given measure. Accordingly, if the State or Federal rules already heavily regulate a given sector, it is reasonable for the State to first look to unregulated parts of the sector for RACT/RACM measures, especially, in light of costs already realized by the regulated sector. A State may conclude that it is unreasonable to further regulate the industry, or that it is only reasonable to impose measures in the latter years of the attainment plan.

Finally, the State should use reason in the extent of its efforts to identify potential control measures. For example, if a review of monitoring data and modeling studies indicates that reductions in SO_2 are much more effective in reducing ambient $PM_{2.5}$ than reductions in other pollutants, we expect that the State will more vigorously identify RACT/RACM measures for SO_2 than for other pollutants. Conversely, if reductions in a given pollutant, even in large quantities, would have trivial impacts on $PM_{2.5}$, less rigor is needed in the State's assessment of controls for that pollutant, because such controls could not contribute to advancing the attainment date. Likewise, where reducing emissions of a pollutant is effective in reducing ambient $PM_{2.5}$, if the emissions inventory for that pollutant is dominated by a given type of emissions source, then it would be appropriate to focus the analysis on measures for that segment of the inventory. No RACT/RACM analysis is needed for pollutants that are not attainment plan precursors for a particular $PM_{2.5}$ nonattainment area.

As supporting information for identification of RACT and RACM, the State ordinarily provides data on technologically feasible control measures:

—A list of all emissions source categories, sources and activities in the nonattainment area (for multi-State nonattainment areas, this would include source categories, sources and activities from all states which make up the area)

—For each source category, source, or activity, an inventory of direct $PM_{2.5}$ and precursor emissions;

—For each source category, source, or activity, a list of technologically feasible emission control technologies and/or measures [27]

—For each technologically feasible emission control technology or measure, the State should provide the following information: (1) The control efficiency by pollutant; (2) the possible emission reductions by pollutant; (3) the estimated cost per ton of pollutant reduced; and (4) the date by which the technology or measure could be reasonably implemented.

Based on this and other relevant information, the State will identify the reasonable measures (potential RACT and RACM) to be included in air quality modeling. (At its option, the State may prefer not to make a judgment on whether certain measures are technically and economically feasible, if it believes they will not contribute to earlier attainment. In that case, the State could include those measures in the modeling, and later exclude them from RACT and RACM by showing that all the excluded measures together would not advance the attainment date by at least 1 year.) As previously mentioned, in determining the attainment date that is as expeditious as practicable, the State should consider impacts on the nonattainment area of intrastate transport of pollution from sources within its jurisdiction, and potential reasonable measures to reduce emissions from those sources.

Modeling to determine the attainment date that is as expeditious as practicable. Second, for purposes of determining the attainment date that is as expeditious as practicable, the State will need to conduct modeling to show the combined air quality impact of all of the potential measures identified in the first step with a modeling analysis for the year 2009. A base case scenario for the year 2009 would project future air quality given implementation of existing measures (Federal, State and local). If this base case scenario demonstrates attainment by 2010, then the State must demonstrate why attainment could not be achieved in an earlier year. (As noted above, given the April 2008 due date for SIP submissions, it may be difficult to achieve earlier attainment in many cases).

If the base case scenario does not demonstrate attainment, then a control case scenario (described below) is needed to examine whether the reasonable, technically and economically feasible measures identified by the State would result in attainment in 2009. The control case scenario would add potential SIP measures—e.g. potential RACT/RACM, plus any candidate intrastate transport measures that the State has identified

[27] The EPA believes that it is not necessary to identify every possible variation of every type of control measure, or all possible combinations of technologies and measures that would apply to a given source or activity if the State has properly characterized the potentially available emissions reductions and their costs. For example, EPA believes that the State can conduct a thorough analysis of VMT reduction measures without including every possible level or stringency of implementation of certain possible measures or combinations of measures for reducing VMT, so long as those measures would not affect the overall assessment of VMT reduction capabilities and the associated costs.

and would be feasible to implement by that year. States in multi-State nonattainment areas are strongly encouraged to collaborate on their modeling analyses. This modeling, along with other information known as weight of evidence considerations, would inform a judgment as to whether reasonable measures could lead to attainment of the standards within 5 years after designation. If the analysis does not demonstrate attainment by April 2010 (2009 analysis year), then the analysis would serve as the technical basis for the State to seek an extension of the attainment date for that area. Further analysis would then be necessary and is required to identify the specific attainment date.

The choice of future years to model beyond 2010 may vary from area to area. Often, modeling potential controls in two different future years may be necessary to support a judgment that a projected attainment year is as expeditious as practicable. If the area is projected to remain over the standard in the early projection year (e.g., 2009) despite the emission reductions from the modeled control measures, but is projected to be well below the standard in the later projection year (e.g., 2012), interpolation and emission inventory analysis could identify an intermediate year as the appropriate attainment date. There may be cases in which modeling a single year is sufficient because modeling of all technically and economically feasible controls results in attainment by a narrow margin in that year.

For many areas, EPA modeling analysis for CAIR and other modeling analyses that have been performed suggest a number of nonattainment areas will have a modest amount (in some cases only a few tenths of a microgram) of needed reductions in ambient levels after 2010 to reach attainment. For any such area, and for areas otherwise expected to attain relatively soon after 2010 (for example, due to substantial reductions in a dominant local source), EPA believes that this analysis should be for a year no later than 2012. A later date (e.g., 2014) may be appropriate for areas with very high $PM_{2.5}$ levels that face difficulty attaining within 10 years.

The EPA believes that it is not reasonable to require States to model each and every year between 2009 and 2014 to determine the appropriate attainment date. Modeling future year inventories is a time consuming and resource intensive process. Multiple models and pre-processors are needed in order to generate year specific emissions for the various emissions sectors (e.g. mobile, non-road, non-EGU point, EGU point, etc.). Because it is not reasonable to model every year, a logical choice often may be to model a year in the middle of the period. As such, we recommend modeling an emissions year no later than 2012 as the initial extension date (which translates to a 2013 attainment date). If this modeling indicates that the area can reach attainment by 2012, then the State can further analyze emissions and strategies to determine if the attainment date can be advanced to an earlier year. If the modeling indicates that the area cannot reach attainment by 2012, then the modeling will serve as further justification for granting a longer attainment date extension (e.g., attainment date of 2015 with modeling for 2014). In that case, additional modeling of 2014 with further emissions controls would be required in order to show attainment. Again, the State should then further analyze emissions and strategies to determine if the attainment date can be advanced to an earlier year between 2012 and 2015.

Additionally, in the discussion of air quality modeling issues in section II.E above, we discuss the benefits of addressing control strategies for multiple pollutants. Part of the challenge of multi-pollutant modeling is coordinating the future modeling years for different pollutants in order to minimize the number of required future year model runs. As part of the requirements of the 8-hour ozone implementation rule, States are currently working on modeling analyses for 2009 and in some cases for 2012 (serious nonattainment areas). For an area that cannot attain the $PM_{2.5}$ NAAQS by 2010, this may be reason to select 2012 as the year to model, so that the State could conduct the modeling for both ozone and $PM_{2.5}$ in tandem. This would, in some cases, allow the pooling of resources (e.g., inventories, model runs, etc.) and provide for faster development of a $PM_{2.5}$ attainment demonstration.

It may also be possible for the State to look at 2009 and 2014 only. In this instance, the State may find sufficient data to interpolate results for the years in between based on estimated changes in emissions.

We emphasize that when a State models later years, that this analysis must take into account potential controls that the State may have determined would not be RACT or RACM for an earlier year. For example, some measures that are impractical to implement by 2009 could be reasonable if implemented by 2010, 2011 or 2012. Thus, when the State models later years, the list of potential controls should be expanded to include technically and economically feasible measures that can be implemented by the analysis year.

Selection of RACT & RACM. Based on this analysis, the State should make decisions on RACT, RACM, intrastate measures, and the attainment date that is as expeditious as practicable. Because EPA is defining RACT and RACM as only those reasonable, technically and economically feasible measures that are necessary for attainment as expeditiously as practicable, the State need not adopt all feasible, reasonable measures. The State may exclude those reasonable measures that, considered collectively, would not advance the attainment date.

Comments and Responses

Comment: A number of commenters generally supported EPA's second proposed alternative to RACT (option 2). Most of these commenters expressed concern that the other options would require the imposition of controls whether or not they were needed to attain the $PM_{2.5}$ standards as expeditiously as practicable. Some State and local commenters also urged EPA to select option 2 as the best interpretation of the RACT requirement for $PM_{2.5}$ because they believe that it will be the most appropriate approach for designing attainment strategies for their particular nonattainment area or areas.

Response: The EPA agrees that these two points are important considerations. After carefully considering the options, we concluded that Option 2 was the most suitable approach for the $PM_{2.5}$ NAAQS. Options 1 and 3 do not reduce the States' burden to analyze potential control measures as the States would still be required to look beyond the mandated RACT for reasonably available control measures (RACM). Moreover, Options 1 and 3 could require imposition of controls on some sources that would not strictly be necessary to attain the NAAQS as expeditiously as practicable. Given the nature of the $PM_{2.5}$ nonattainment problem, EPA concluded that an interpretation that provides the maximum flexibility is a better approach.

Comment: Some commenters recommended that EPA modify proposed option 2 to include a tons-per-year threshold. Under such an approach, the States and EPA would only require RACT for sources whose emissions were above the threshold. Most of these comments recommended a RACT threshold of 100 tons per year. These commenters expressed concern that if option 2 were implemented

without such a threshold, States would be burdened with conducting RACT analyses for very small sources or source categories with low emissions.

Response: The EPA believes that under the approach chosen for the final rule in which RACT is considered to be a part of the overall RACM process, it would be difficult to define a threshold that would apply for all types of sources and for all types of control measures in all nonattainment areas. It has not been common practice under past EPA policy to establish or use an emissions threshold when considering sources for possible emission reductions as part of a RACM analysis to show attainment as expeditiously as practicable. Indeed, many of the control technique guidelines for VOC RACT do not recommend an emissions threshold. A state needing significant emission reductions to attain the standards in a given area even by 2015 would likely conclude that controls should be considered on smaller sources. In contrast, a State with an area that exceeds the standard by only a few tenths of a microgram per cubic meter may not need to consider controls on smaller source to reach attainment as expeditiously as practicable. The EPA has selected option 2 for interpretation of the RACT requirement for $PM_{2.5}$, in part, specifically because that approach contemplates that States will conduct an appropriate analysis of the spectrum of source categories and potential controls available. To cut off such analysis at a set emissions-based cut point for all sources and all areas would undermine one of the key benefits of the approach. Accordingly, EPA disagrees with comments that option 2 should include a nationally-defined threshold for the size of sources or source categories that require RACT analyses.

Comment: A number of commenters supported EPA's first and third proposed alternative approaches to RACT (option 1 and option 3). Commenters supporting these two options used similar reasoning. Commenters cited the statutory language in section 172(c)(1) requiring that the attainment plan provide for ''at a minimum'' the adoption of RACT. Accordingly, these commenters argued that RACT is an independent, minimum requirement of attainment plans irrespective of the attainment demonstration and that option 2, which would not require the adoption of RACT for all sources, has no policy or legal justification. Other commenters noted that option 1 would be much easier to implement, because RACT would be defined according to technical reasonableness and would not hinge on complicated determinations involving attainment demonstrations. Some commenters argued that option 1 provides for greater equity, because similar measures would be required for similar sources for all nonattainment areas. Finally, some commenters believed that it is inherently inconsistent to assert that plans have met the requirement for attainment ''as expeditiously as practicable'' without applying RACT to all major sources.

Response: The EPA disagrees with these comments. The EPA believes that option 2 is fully consistent with section 172(c)(1). Section 172(c)(1) requires that attainment plans must provide for the implementation of RACM as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of RACT). Contrary to the commenters' assertions, this language does not demonstrate that RACT is required for all sources, independent of RACM and attainment demonstrations. Moreover, this provision does not require RACT whether or not imposition of technology would advance the attainment date. Instead, section 172(c)(1) explicitly provides that RACT is included within the definition of RACM, and EPA has previously determined that the CAA only requires such RACM as will provide for attainment as expeditiously as practicable. (See 57 FR 13498, 13560). The courts have deferred to this interpretation and concluded that EPA interprets RACM as a collection of reasonable measures that would advance the attainment date. See *Sierra Club* v. *EPA*, 294 F.3d 155, 162 (D.C. Cir. 2002); see also *Sierra Club* v. *EPA*, 314 F.3d 735, 744 (5th Cir. 2002). The CAA does not ''compel [ ] a State to consider whether any measure is 'reasonably available' without regard to whether it would expedite attainment in the relevant area.'' *Sierra Club* v. *EPA*, 294 F.3d at 162. The EPA concludes that because section 172(c)(1) establishes that RACT is a part of RACM, EPA is reasonably applying the same interpretation to the RACT requirement for $PM_{2.5}$. The RACT is a part of the collection of measures that are necessary to reach attainment as expeditiously as practicable. It is thus directly related to what a specific area needs to attain the NAAQS, and States need not implement reasonably available measures that would not advance the attainment date as part of the $PM_{2.5}$ RACT requirement.

The EPA also finds that option 2 is consistent with the statutory language providing that a State must apply RACT to existing sources, ''at a minimum,'' to meet its requirement to apply RACM. We interpret the ''at a minimum'' clause to mean that when a State determines that control of a specified existing stationary source(s) is necessary to attain, the State must apply RACT to that source. Further, EPA believes this requirement for RACT applies to stationary sources as a group, and not to each stationary source.

The EPA finds sound policy reasons for choosing option 2. While an approach that provided for application of the same controls in all areas would provide for more equity across areas, EPA emphasizes that equity is only one of many factors considered by EPA when deciding between options 1, 2 and 3. The EPA believes that it is also important to ensure that control strategies focus on the most effective measures with the greatest possibility for significant air quality improvements. In addition, while EPA agrees that options 1 and 3 could provide for greater ease of implementation, this is also only one of the factors EPA considered when deciding between the proposed options. Under option 2, States have a greater burden and responsibility to identify the local strategy that is tailored to their particular air quality problem. At the same time, the States have the ability to identify the sources with the greatest impact on nonattainment and to identify a sound strategy that achieves attainment in the most sensible manner. The EPA believes that approaching RACT and RACM in this manner is consistent with the overall philosophy imbedded in the SIP program since its inception in the late 1960s and early 1970s.

Comment: Some commenters believed that the proposed RACM requirement was too broad. These commenters believed that the requirement to analyze the entire ''universe'' of possible measures was too burdensome for States. Commenters felt this was especially true in light of the lack of federally issued CTG and ACT documents for $PM_{2.5}$ and its precursors for all potential source categories.

Response: As explained earlier, States should apply ''reason'' in identifying measures to evaluate as potential RACM/RACT. We recognize that States are implementing the $PM_{2.5}$ standard for the first time, and do not have the long history and experience in implementing $PM_{2.5}$ as they have in implementing the PM_{10} and ozone standards. Accordingly, we expect that both the States and EPA will expend extra effort in developing and evaluating attainment plans that contain appropriate controls. A number

of resources exist to provide States with information on potential control measure costs and emissions reductions. We intend to facilitate the sharing of information through a control measure website and other efforts, and expect that States will develop screening methods to reduce the burden of analysis.

Comment: One commenter asserted that EPA should not require the analysis for, or implementation of, RACT and RACM for sources throughout the entire nonattainment area, and should permit States to focus only on sources located in smaller specific ''problem areas'' within the nonattainment area.

Response: The EPA designated areas nonattainment based upon analysis of the geographic area with sources that ''contribute'' to the violation of the NAAQS in the area, in accordance with section 107(d). These designations are based upon, among other things, a network of monitors that the State and EPA previously agreed represented the ambient air concentrations throughout the area. Additional analysis of information during the designation process indicated those areas that contributed to the violations at the violating monitor because of, among other things, the amount of emissions in such adjoining areas. Accordingly, the State in which a nonattainment area is located must evaluate the full range of sources of $PM_{2.5}$ and its precursors throughout the designated nonattainment area during the development of the SIP. The EPA agrees that there are some nonattainment areas where one or a few large emissions sources may be causing localized concentrations at a monitor that are much higher than those within the remainder of the nonattainment area. For such areas, the nonattainment strategy will likely not succeed without addressing those sources. The EPA does not, however, believe it is acceptable that the nonattainment strategy focus only on those sources, because additional reductions within the nonattainment area would still have the potential to advance the attainment date. Exempting portions of the nonattainment area could expose a portion of the public residing downwind in the area to exposure to levels of $PM_{2.5}$ that exceed the NAAQS for longer than necessary, and the health detriments from such exposure, merely to minimize the impact of having to impose control strategies on sources upwind. Moreover, to the extent that monitoring in one portion of a nonattainment area indicates violations in multiple portions of the area, a strategy that solely focused upon the sources in the immediate vicinity of the monitor might fail to assure that the NAAQS is achieved throughout the area. Because NAAQS violations generally reflect a combination of regional scale, metropolitan scale, and local scale impacts, and all three scales must be addressed, EPA requires RACT/RACM submittals to address sources throughout the nonattainment area.

Comment: Some commenters agreed with EPA's view that State's RACM analysis must address those measures that a State declines to adopt and must show whether the combined measures would cumulatively advance the attainment date by at least 1 year. One commenter questioned the legal basis for EPA's determination that the only controls necessary to attain the $PM_{2.5}$ NAAQS as expeditiously as practicable are those that would cumulatively advance an area's projected attainment date by at least one calendar year. The commenter suggested that control measures that would advance attainment by a smaller increment ''would meet the criteria endorsed in Sierra Club [Sierra Club v. EPA, 294 F.3d 155 (D.C. Cir 2002)] by 'expedit[ing] attainment in the relevant area.' ''

Response: The EPA has consistently interpreted RACM as a collection of measures that would advance the attainment date by at least 1 year, and the courts have determined that the statutory RACM requirement is ambiguous and deferred to EPA's interpretation of the requirement. See *Sierra Club* v. *EPA*, 314 F.3d 735, 744 (5th Cir. 2002); see also *Sierra Club* v. *EPA*, 294 F.3d, 155 162 (D.C. Cir. 2002). Contrary to the commenter's suggestion, the court in *Sierra Club* v. *EPA*, did not endorse specific criteria for identifying control measures that expedite attainment, but instead deferred to EPA's interpretation of an ambiguous statutory term. The courts deferred to EPA's interpretation after reviewing EPA's approval of State SIP submissions. The EPA conducts such reviews consistent with its determination that the CAA only requires such RACM as will provide for attainment as expeditiously as practicable, and its belief that it would be unreasonable to require implementation of measures that would not in fact advance attainment. See 57 FR 13498, 13560 (April 15, 1992); see also 44 FR 20372, 20374 (April 4, 1979). In considering whether a collection of measures would advance the attainment date of an area, EPA has previously interpreted the phrase ''advance the attainment date'' as meaning that the attainment date would be advanced by at least 1 year. See e.g., 66 FR 57160, 57182 (Nov. 14, 2001) (approval of Houston SIP); 66 FR 586 (Jan 3. 2001) (approval of DC area SIP). Further, EPA's use of a one-year increment in determining whether a collection of measures would advance the attainment date is reasonable and consistent with the fact that all areas will be designing attainment demonstrations for the annual $PM_{2.5}$ standard. Section 172(a)(2)(C) statute uses 1 year as the increment by which attainment date extensions can be granted. Thus, requiring evaluation of whether control measures would advance attainment by an increment of 1 year is a reasonable approach for the $PM_{2.5}$ NAAQS.

Comment: Some commenters recommended that EPA consider not requiring a RACM analysis for areas projected to attain the standards within 5 years of designation, i.e., by April 2010 for the areas currently designated nonattainment. One commenter suggested that practical considerations would make it impossible for any State projected to attain by 2010 to advance the attainment date by a year. This commenter noted that because measures to provide for attainment by 2010 must be implemented by the beginning of 2009, and SIPs are not submitted until April 2008, it would impossible to advance the implementation of measures by 1 year (that is, the beginning of 2008).

Response: The EPA generally agrees that given the time constraints it will be difficult for States with areas currently designated nonattainment to devise, adopt, and implement RACM measures to advance the attainment date before 2010. At the same time, however, we note that nothing precludes States from taking early action and we encourage States to take actions to reduce $PM_{2.5}$ concentrations where feasible even before the SIPs are submitted. RACM is required by the CAA and thus EPA cannot waive the requirement for the analysis. At the same time, EPA recognizes that a streamlined analysis may be appropriate given the short time periods involved.

3. Observations and Considerations in Determining RACT and RACM

a. Background

The preamble to the proposed rule included a discussion of general considerations for RACT (70 FR 66020 and 66021, latter part of section III.I.6) and RACM (70 FR 66028, section III.1.15). The preamble to the final rule retains this discussion with some modifications and restructuring to

reflect the combined approach to RACT and RACM

b. Final Rule

General considerations. Once the State has identified measures and technologies that are available for implementation in the nonattainment area, then it must evaluate those measures to determine whether implementation of such measures are reasonable, and would collectively advance attainment. Many of the factors that the State should take into consideration in determining whether a measure is ''reasonable'' are related to the measure's technical and economic feasibility. Since RACM applies to area and mobile sources as well as stationary sources, the State should consider other factors as well in conducting its RACM analysis. For example, in many cases obtaining emissions reductions from area and mobile sources is achieved not by adding control technology to a specific emissions source, but by reducing the level of activity of a fleet of vehicles or by modifying a type of commercial process. In these situations, the State should also consider local circumstances such as infrastructure, population, or workforce and the time needed to implement the measure in light of the attainment date.

The EPA believes that while areas projected to attain within 5 years of designation as a result of existing national measures should still be required to conduct a RACT and RACM analysis, such areas may be able to conduct a limited RACT and RACM analysis that does not involve additional air quality modeling. A limited analysis of this type could involve the review of available reasonable measures, the estimation of potential emissions reductions, and the evaluation of the time needed to implement these measures. If the State could not achieve significant emissions reductions by the beginning of 2008 due to time needed to implement reasonable measures or other factors, then it could be concluded that reasonably available local measures would not advance the attainment date. In lieu of conducting air quality modeling to assess the impact of potential RACT and RACM measures, existing modeling information could be considered in determining the magnitude of emissions reductions that could significantly affect air quality and potentially result in earlier attainment. If the State, in consultation with EPA, determines from this initial, more limited RACT and RACM analysis that the area may be able to advance its attainment date through implementation of reasonable measures, then the State would conduct a more detailed RACT and RACM analysis.

Observations on control opportunities. The implementation of the $PM_{2.5}$ NAAQS is in its initial stages, and many of the designated $PM_{2.5}$ nonattainment areas are not current or former PM_{10} nonattainment areas. Thus, some existing stationary sources in these areas may currently be uncontrolled or undercontrolled for $PM_{2.5}$ or $PM_{2.5}$ precursors. Further, to this point in time, emissions controls for existing sources in these areas may have focused primarily on particulate matter that is filterable at stack temperatures and thus may not adequately control condensable emissions. In addition, States should bear in mind that the controlled sources may have installed emission controls 15 years ago or more, and there may now be cost-effective opportunities available to reduce emissions further through more comprehensive and improved emissions control technologies, or through production process changes that are inherently lower in emissions.

Moreover, improved monitoring methods may enhance the ability of sources to maintain the effectiveness of installed emissions controls and to reduce emissions by detecting equipment failures more quickly. For example, State imposition of requirements for more frequent monitoring (e.g., continuous opacity monitors, PM continuous emissions monitors, etc.) may provide greater assurance of source compliance and quicker correction of inadvertent upset emissions conditions than existing approaches.

Even in former or current PM_{10} nonattainment areas, existing requirements for controlling direct PM emissions (e.g., with a baghouse or electrostatic precipitator) may not have been revised significantly since the 1970's. When EPA established the PM_{10} standards in 1987, we stated in the preamble that it was reasonable to assume that control technology that represented RACT and RACM for total suspended particulates (TSP) should satisfy the requirement for RACT and RACM for PM_{10}. 52 FR 24672 (July 1, 1987). The basis for EPA's belief was that controls for PM_{10} and TSP would both focus on reducing coarse particulate matter, and specifically that fraction of particulate matter that is solid (rather than gaseous or condensable) at typical stack temperatures. However, emission controls to capture coarse particles in some cases may be less effective in controlling $PM_{2.5}$. For this reason, there may be significant opportunities for sources to upgrade existing control technologies [28] and compliance monitoring methods to address direct PM emissions contributing to fine particulate matter levels with technologies that have advanced significantly over the past 15 years.

Precursor Controls. It will be important for States to conduct RACT and RACM determinations for stationary sources of $PM_{2.5}$ precursors as well as direct $PM_{2.5}$ emissions although, as noted above, the known atmospheric chemistry of the area may dictate the necessary rigor of this analysis. A significant fraction of $PM_{2.5}$ mass in most areas violating the standards is attributed to secondarily-formed components such as sulfate, nitrate, and some organic PM, and EPA believes that certain stationary sources of precursors of these components in nonattainment areas currently may be poorly controlled. Accordingly, to address these precursors, States should review existing sources for emission controls or process changes that could be reasonably implemented to reduce emissions from activities such as fuel combustion, industrial processes, and solvent usage.

Multi-State Nonattainment Areas. States in multi-State nonattainment areas will need to consult with each other on appropriate level of RACT and RACM for that area. We anticipate that States may decide upon RACT and RACM controls that differ from State to State, based upon the State's determination of the most effective strategies given the relevant mixture of sources and potential controls in the relevant nonattainment areas. So long as each State can adequately demonstrate that its chosen RACT and RACM approach will provide for meeting RFP requirements and for attainment of the NAAQS as expeditiously as practicable for the nonattainment area at issue, we anticipate approving plans that may elect to control a somewhat different mix of sources or to implement somewhat different controls as RACT and RACM. Nevertheless, States should consider RACT and RACM measures developed for other areas or other States. EPA may consider such measures in assessing the approvability of a State's SIP.

c. Comments and Responses

Comment: In the proposed rule, EPA indicated that States could consider the ''social acceptability'' of measures as a

[28] For example, see past EPA guidance on $PM_{2.5}$ control technologies: Stationary Source Control Techniques Document for Fine Particulate Matter (EPA–452/R–97–001), EPA Office of Air Quality Planning and Standards, October 1998.

factor in the determination of what constitutes RACM in a given area. A number of commenters recommended that EPA eliminate use of this factor. Some commenters questioned whether States or EPA had the legal authority to exclude measures from consideration based on social acceptability or popularity, if the measures are technically and economically available, and are needed to attain the NAAQS for protection of public health. Others expressed concerns that inclusion of such a factor would inevitably result in the elimination of controls for area and mobile sources and for this reason would unfairly focus emissions reduction strategies on industrial sources of $PM_{2.5}$ and precursors.

Response: The EPA believes that in developing RACM measures, it is important that States not rely unduly on measures that would be very difficult to enforce in practice. We discourage States from relying on measures that on paper may seem reasonably available but in practice might fail to achieve benefits due to the problems and costs of effectively enforcing these measures. However, we recognize that the CAA does not identify ''social acceptability'' as a factor in the definition of what may constitute RACT or RACM, and more generally the CAA does not establish a preference for measures that affect industrial sources instead of the general public and are therefore more likely to be ''socially acceptable.'' Therefore, given the concerns raised by commenters that establishment of ''social acceptability'' as a factor in the RACM analysis is without basis in the CAA and might result in inappropriate skewing of control strategies, we have removed this term from the final rule. We reiterate, however, that capability of effective implementation and enforcement are relevant considerations in the RACM analysis, even though public ''unpopularity'' is not. Moreover, in assessing the efficacy of measures and the credit they should be given in the context of attainment demonstrations or RFP calculations, EPA believes that such considerations are important.

4. What Factors Should States Consider in Determining Whether an Available Control Technology or Measure Is Technically Feasible?

a. Background

The following provides guidance for States to consider in determining whether an available control technology is technologically feasible.

b. Final Rule

The technological feasibility of applying an emission reduction method to a particular source should consider factors such as the source's process and operating procedures, raw materials, physical plant layout, and any other environmental impacts such as water pollution, waste disposal, and energy requirements. For example, the process, operating procedures, and raw materials used by a source can affect the feasibility of implementing process changes that reduce emissions and the selection of add-on emission control equipment. The operation and longevity of control equipment can be significantly influenced by the raw materials used and the process to which it is applied. The feasibility of modifying processes or applying control equipment also can be influenced by the physical layout of the particular plant. The space available in which to implement such changes may limit the choices and will also affect the costs of control.

Reducing air emissions may not justify adversely affecting other resources by increasing pollution in bodies of water, creating additional solid waste disposal problems or creating excessive energy demands. An otherwise available control technology may not be reasonable if these other environmental impacts cannot reasonably be mitigated. For analytic purposes, a State may consider a $PM_{2.5}$ control measure technologically infeasible if, considering the availability (and cost) of mitigating adverse impacts of that control on other pollution media, the control would not, in the State's reasoned judgment, provide a net benefit to public health and the environment. However, in many past situations, States and owners of existing sources have adopted $PM_{2.5}$ control technologies with known energy penalties and some adverse effects on other media, based on the reasoned judgment that installation of such technology would result in a net benefit to public health and the environment. States should consider this in determining technical feasibility. The costs of preventing adverse water, solid waste and energy impacts should be included in assessing the economic feasibility of the $PM_{2.5}$ control technology.

One particular cross-media issue relates to concentrated animal feeding operations (CAFOs). Should a State determine that reductions of direct $PM_{2.5}$ or $PM_{2.5}$ precursors from CAFOs are necessary for attainment in a nonattainment area, EPA strongly suggests that the State address these reductions from a cross-media perspective. Since 2003, EPA and many stakeholders have been interested in developing a framework to enable CAFOs to pursue superior environmental performance across all media. We are aware that today some CAFOs voluntarily conduct whole-farm audits to evaluate releases of pollutants to all media through Environmental Management Systems, self-assessment tools, performance track, ISO 14001 certification, and State-approved trade offs in meeting regulatory thresholds between air and water that accomplish the best overall level of environmental protection given State and local conditions. The EPA continues to believe the development of new and emerging technologies offers the potential to achieve equivalent or greater pollutant reductions than achieved solely by effluent guidelines and standards. Many of these are superior from a multimedia perspective, and EPA would like to encourage superior multimedia solutions. SIPs which need to address ammonia may provide a unique opportunity to encourage multimedia approaches at CAFOs. For example, the addition of animal by-products provides a valuable source of nutrients for crops, improves soil structure which enhances soil permeability, and adds valuable organic matter that improves soil health. However, inappropriate application can lead to air and water quality concerns or the improvement of one media at the cost of another. Optimal application technologies and rates reduce potential air and water quality standards violations. The EPA does not want to discourage approaches that are superior from a cross media perspective.

The EPA recommends that States evaluate alternative approaches to reducing emissions of particulate matter by reviewing existing EPA guidance [29] and other sources of control technology information. The EPA's 1998 guidance presents information on topics such as the design, operation and maintenance of general particulate matter control systems such as electrostatic precipitators, fabric filters, and wet scrubbers. The filterable particulate matter collection efficiency of each system is discussed as a function of particle size. The guidance document also provides information concerning

[29] Stationary Source Control Techniques Document for Fine Particulate Matter (EPA–452/R–97–001), EPA Office of Air Quality Planning and Standards, October 1998. See also: Controlling SO_2 Emissions: A Review of Technologies (EPA/600/R–00/093), EPA Office of Research and Development, November 2000.

other relevant considerations such as energy and environmental considerations, procedures for estimating costs of particulate matter control equipment, and evaluation of secondary environmental impacts. Because control technologies and monitoring approaches are constantly being improved, the State should also consider more updated or advanced technologies not referenced in this 1998 guidance when conducting a RACT determination. Emissions reductions may also be achieved through the application of monitoring and maintenance programs that use critical process and control parameters to verify that emission controls are operated and maintained so that they more continuously achieve the level of control that they were designed to achieve.[30]

c. Comments and Responses

Comment: One commenter noted that the guidance for ''technical feasibility'' implies that States look at individual sources with a BACT-like case-by-case analysis. The commenter recommended that source owners conduct such a site-specific analysis and submit the analysis to the State through the permitting process.

Response: While the analytical analysis to identify RACT is similar to BACT, as noted above, EPA in the past has issued CTGs that describe the presumptive norm for RACT controls for a given industry, but that allow for case-by-case considerations for a given source. Where States wished to require source owners to conduct such a site-specific analysis as part of the control technology review, EPA supports this type of process. On the other hand, EPA does not believe it would be appropriate to require all RACT-eligible sources to conduct such an analysis, given that States have the primary responsibility for identifying and analyzing measures for such sources.

5. What Factors Should States Consider in Determining Whether an Available Control Technology or Measure Is Economically Feasible?

a. Background

The follow provides guidance for States to consider in determining whether an available control technology is economically feasible for purposes of identifying reasonably available control measures. This guidance is slightly modified from our proposal.

[30] See EPA's Web site for more information: *http://www.epa.gov/ttn/emc/monitor.html.*

b. Final Rule

Economic feasibility encompasses considerations such as whether the cost of a potential measure is reasonable considering attainment needs of the area and the costs of other measures, and whether the cost of a measure is reasonable for the regulated entity to bear, in light of benefits.

While many States generally establish RACT requirements for a category of sources, the Act does not require the same level of control on all sources in a category, nor does the Act require that each source be controlled individually. Similar sources may have different marginal costs, profit margins and abilities to pass costs through to the consumer. These factors are appropriate to consider in determining whether a given level of control is appropriate for an individual source or category of sources. Accordingly, there is no presumption that a given source must bear a cost similar to any other source.

States should consider the capital costs, annualized costs, cost effectiveness of an emissions reduction technology, and effects on the local economy in determining whether a potential control measure is reasonable for an area or State. One available reference for calculating costs is the EPA Air Pollution Control Cost Manual,[31] which describes the procedures EPA uses for determining these costs for stationary sources. The above costs should be determined for all technologically feasible emission reduction options if such measure is inherently ''reasonably available'' (e.g., not absurd or clearly impractical). States may give substantial weight to cost effectiveness in evaluating the economic feasibility of an emission reduction technology. The cost effectiveness of a technology is its annualized cost ($/year) divided by the emissions reduced (i.e., tons/year) which yields a cost per amount of emission reduction ($/ton). Cost effectiveness provides a value for each emission reduction option that is comparable with other options and other facilities. Where multiple control options exist for a given source or source category, States should consider both the cost effectiveness (dollars per ton) of each option, and the incremental cost effectiveness per ton between the options (incremental increase in cost between options divided by the incremental tons reduced).

In determining whether a given measure is reasonable, States may consider costs per ton of other measures previously employed to reduce that pollutant, but similar costs are not conclusive. As discussed above, States may evaluate equity considerations in weighing the economic feasibility of imposing a measure on a given source or source category.

We anticipate that States may decide upon RACT and RACM controls that differ from State to State, based on the State's determination of the most effective strategies given the relevant mixture of sources and potential controls in the relevant nonattainment areas, and differences in the difficulty of reaching attainment.

In considering what level of control is reasonable, EPA is not proposing a fixed dollar per ton cost threshold for RACT, consistent with the views of multiple commenters. Areas with more serious air quality problems typically will need to obtain greater levels of emissions reductions from local sources than areas with less serious problems. Where essential reductions are more difficult to achieve (e.g., because many sources are already controlled), the cost per ton of control may necessarily be higher.

It is not appropriate to assume that the same cost per ton range is reasonable for direct $PM_{2.5}$ and different precursors, because an equal amount of emission reduction in different pollutants has a different impact on $PM_{2.5}$ ambient levels. For example, in a given nonattainment area, reductions of direct $PM_{2.5}$ emissions may prove more expensive than reductions of NO_X emissions, but the resulting benefits of reductions of direct $PM_{2.5}$ might warrant the higher costs. A State should consider this differential impact on ambient $PM_{2.5}$ in considering RACT for controlling different pollutants. During the SIP process, States and regional planning organizations typically conduct sensitivity modeling that can provide this information. Also, the PM NAAQS RIA provides information on the differential impact of $PM_{2.5}$ and PM precursor reductions on ambient $PM_{2.5}$ levels in various areas.[32]

One of the factors that could affect estimated compliance costs of an emission reduction measure is the timing of its implementation. Hypothetically, if a short compliance period were contemplated for a set of sources, and if the short compliance

[31] *EPA Air Pollution Control Cost Manual—Sixth Edition* (EPA 452/B–02–001), EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC, Jan 2002.

[32] See: U.S. EPA 2006. *Regulatory Impact Analysis for the Particulate Matter National Ambient Air Quality Standards.* Air Benefits and Cost Group, Office of Air Quality Planning and Standards, Research Triangle Park, NC, October 6, 2006. Appendix A provides an analysis of estimated benefits and costs of attaining the 1997 PM NAAQS standards in 2015.

period resulted in high demand for a limited supply of labor or other resources, compliance costs could be higher than if the same measure were implemented by a later compliance date. In such a case it may be reasonable for the State to find that the measure is reasonable only if implemented by the later date.

If a source contends that a source-specific RACT level should be established because it cannot afford the technology that appears to be RACT for other sources in its source category, the source can support its claim with such information as:

—Fixed and variable production costs ($/unit)
—Product supply and demand elasticity,
—Product prices (cost absorption vs. cost pass-through),
—Expected costs incurred by competitors,
—Company profits once the technology or measure is in operation (considering the annualized costs and the marginal costs of alternative technologies and measures),
—Employment costs, and
—Any other unique factor(s) particular to the individual source.

Finally, the EPA clarifies that if the State demonstrates through economic analysis that the imposition of the measure would cause unacceptable economic disruption for the local economy, that is, a plant shutdown or a severe curtailment in plant employment or output, a State may reject the measure as not reasonable to reach attainment as expeditiously as practicable.

c. Comments and Responses

Comment: Some commenters agreed with EPA's proposal not to establish presumptive cost-effectiveness thresholds.

Response: The EPA agrees with the commenters.

Comment: A number of commenters expressed concerns over the references to health benefits as a consideration in whether measures are technically or economically available. Some commenters believed this is a consideration not authorized by the CAA. Others believed that consideration of benefits, in combination with EPA's estimates of benefits per ton, would have the effect of converting RACT to more stringent LAER levels. Some commenters expressed concerns whether States had the resources or expertise to conduct cost-benefit analyses for this purpose.

Response: The EPA wishes to clarify that the reference to health benefits does not mean that a cost-benefit, or a detailed health benefits assessment, is a necessary part of a control strategy demonstration. We also wish to clarify that EPA is not requiring that the costs of all technologies and measures for $PM_{2.5}$ and precursors be deemed acceptable at any dollar/ton levels at or below the calculated monetized benefits per ton of reduction. We do, however, continue to believe that the significant benefits associated with $PM_{2.5}$ ambient reductions is a relevant consideration in control strategy development. The EPA disagrees that this limited consideration of benefits would convert the RACT process to the equivalent of LAER.

Comment: One commenter objected to EPA's proposed requirement that States consider competitive factors such as production costs, demand elasticity, product prices, and cost incurred by competitors in the determination of RACT. The commenter believed that this information is generally not accessible to States or industrial facility owners, and is not necessary for a RACT determination.

Response: The EPA generally disagrees that this type of information is unavailable. For example, EPA calculates or reviews this type of data on a regular basis as part of our work on MACT, NSPS, and other emissions standards. A document that describes these types of analyses and the data used to prepare them is the OAQPS Economic Resource Manual found at *http://www.epa.gov/ttn/ecas/analguid.html.* EPA believes that this issue is most relevant to category-wide RACT rules where a source seeks a case-by-case exemption. Further, EPA believes most RACT determinations will be developed through case-by-case analyses rather than rules affecting entire source categories. Accordingly, this analysis likely will be relevant in few cases.

6. What Specific Source Categories and Control Measures Should a State Evaluate When Determining RACT and RACM for a Nonattainment Area?

a. Background

Section 172 does not provide a specific list of source categories and control measures that must be evaluated for RACT and RACM for $PM_{2.5}$. However, section 172(c)(3) indicates that the attainment plan must include a ''comprehensive, accurate, current, inventory of actual emissions from all sources of the relevant pollutant.'' This indicates that States should look broadly at the different types of sources in the nonattainment area. We recognize that $PM_{2.5}$ is a new NAAQS without a long history of implementation as with ozone. Therefore, we included a list of potential RACM measures in the preamble to the proposed rule, based upon a review of information about the contribution of various sources to emissions inventories and a review of potential control measures for such sources. We requested comment on the specific sources and potential control measures recommended for RACM analysis on this list. Based on comments received and additional information available to EPA since the proposal, we have made some changes to the list. We also refer to this list of potential ''RACT and RACM'' measures for the combined approach to RACT and RACM in the final rule.

In the preamble to the proposed rule, EPA indicated that due to the short time available, it does not plan to develop new control techniques guidance (CTG) or ACT documents specifically for purposes of $PM_{2.5}$ implementation. The EPA indicated that other information was available on control technologies, and EPA also indicated its intention to maintain an updated list of references for new $PM_{2.5}$ control technology information.

b. Final Rule

Emission reduction measures constituting RACM should be determined on an area-by-area basis. We believe that a State should consider each of the measures listed in this section to determine if each measure is reasonably available in the applicable nonattainment area. However, we do not presume that each of these measures is reasonably available in each nonattainment area.

We recommend that each State use the list of source categories in this section as a starting point for identifying potentially available control strategies (regulatory and voluntary) for a nonattainment area. States are encouraged and expected to add other potentially available measures to the list based on its knowledge of the particular universe of emissions sources in the area and comments from the general public. We expect that, depending on the potential measure being analyzed, the State's degree of evaluation will vary as appropriate. Detailed information on emission control technologies is available from a number of sources.[33] The EPA intends to maintain a website with links to sources of information for

[33] There are a number of sources of information on technologies for reducing emissions of $PM_{2.5}$ and its precursors. Links are provided to a number of national, state and local air quality agency sites from EPA's $PM_{2.5}$ Web site: *http://www.epa.gov/pm/measures.html.*

controlling emissions of direct particulate matter and PM precursors.

As discussed in section II.J.5. above, EPA recognizes that control technology guidance for certain source categories has not been updated for many years. Section 183(c) of the CAA, which addresses control technologies to address ozone nonattainment problems, requires EPA to ''revise and update such documents as the Administrator determines necessary.'' As new or updated information becomes available States should consider the new information in their RACT determinations. A State should consider the new information in any RACT determinations or certifications that have not been issued by the State as of the time such updated information becomes available.

Stationary Source Measures

—Stationary diesel engine retrofit, rebuild or replacement, with catalyzed particle filter

—New or upgraded emission control requirements for direct $PM_{2.5}$ emissions at stationary sources (e.g., installation or improved performance of control devices such as a baghouse or electrostatic precipitator; revised opacity standard; improved compliance monitoring methods)

—Improved capture of particulate emissions to increase the amount of $PM_{2.5}$ ducted to control devices, and to minimize the amount of $PM_{2.5}$ emitted to the atmosphere, for example, through roof monitors

—New or upgraded emission controls for $PM_{2.5}$ precursors at stationary sources (e.g., SO_2 controls such as wet or dry scrubbers, or reduced sulfur content in fuel; desulfurization of coke oven gas at coke ovens; improved sulfur recovery at refineries; increasing the recovery efficiency at sulfuric acid plants)

—Energy efficiency measures to reduce fuel consumption and associated pollutant emissions (either from local sources or distant power providers)

—Measures to reduce fugitive dust from industrial sites

Mobile Source Measures

—Onroad diesel engine retrofits for school buses,[34] trucks and transit buses using EPA-verified technologies

—Nonroad diesel engine retrofit, rebuild or replacement, with catalyzed particle filter [35]

—Diesel idling programs for trucks, locomotive, and other mobile sources [36]

—Transportation control measures (including those listed in section 108(f) of the CAA as well as other TCMs), as well as other transportation demand management and transportation systems management strategies [37]

—Programs to reduce emissions or accelerate retirement of high emitting vehicles, boats, and lawn and garden equipment

—Emissions testing and repair/maintenance programs for onroad vehicles

—Emissions testing and repair/maintenance programs for nonroad heavy-duty vehicles and equipment [38]

—Programs to expand use of clean burning fuels [39]

—Low emissions specifications for equipment or fuel used for large construction contracts, industrial facilities, ship yards, airports, and public or private vehicle fleets

—Opacity or other emissions standards for ''gross-emitting'' diesel equipment or vessels

Area Source Measures

—New open burning regulations and/or measures to improve program effectiveness such as programs to reduce or eliminate burning of land clearing vegetation

—Programs to reduce emissions from woodstoves and fireplaces including outreach programs, curtailments during days with expected high ambient levels of $PM_{2.5}$, and programs to encourage replacement of woodstoves when houses are sold

—Controls on emissions from charbroiling or other commercial cooking operations

—Reduced solvent usage or solvent substitution (particularly for organic compounds with 7 carbon atoms or more, such as toluene, xylene, and trimethyl benzene)

Category-Specific Guidelines on innovative approaches. The EPA has issued a number of category specific guidelines on approaches to taking into account innovative approaches to emissions reductions for purposes of SIPs. Categories currently covered by these guidelines include: (1) Electric-sector Energy Efficiency and Renewable Energy Measures; (2) Long Duration Switch Yard Locomotive Idling; (3) Long Duration Truck Idling; (4) Clean Diesel Combustion Technology; and (5) Commuter Choice Programs. See *http://www.epa.gov/ttn/airinnovations/measure_specific.html.*

c. Comments and Responses

Comment: Some commenters recommended that EPA provide new CTGs or other control technology review documents for purposes of assisting States to address $PM_{2.5}$ and its precursors, because the information in some current documents is out-dated.

Response: The EPA recognizes that issuance of new or updated CTGs specifically tailored for $PM_{2.5}$ would be useful. Unfortunately, limitations on time and resources preclude EPA from developing such CTGs in advance of the SIP submission date. The EPA cannot delay the statutorily specified outer date for SIP submission. However, EPA believes that there are already many sources of information and guidance on key source categories. To the extent that States need to examine potential control measures for sources never addressed before in any area or other context for a previous NAAQS, EPA anticipates that it will work closely with States during the process of plan development and approval to ensure an appropriate approach.

Comment: A number of commenters expressed concerns with references to the STAPPA and ALAPCO *Menu of Options* document. Some commenters believed that this document must be subject to formal review and comment to ensure appropriate stakeholder input.

Response: The language in the final preamble has been changed to refer to a Web site EPA maintains that provides access to a variety of information sources regarding control technologies that may be useful to States to consider in developing their $PM_{2.5}$ SIPs. These links include evaluations developed by government and nongovernment organizations. One such source with potentially useful information is the STAPPA and ALAPCO *Menu of Options.* However, EPA is not specifically endorsing any of the specific evaluations as being appropriate in any specific situation. Rather, we think documents such as the

[34] See Clean School Bus USA program at *http://www.epa.gov/cleanschoolbus/.* See also: ''What You Should Know About Diesel Exhaust and School Bus Idling,'' (June 2003, EPA420–F–03–021) at *http://www.epa.gov/otaq/retrofit/documents/f03021.pdf.*

[35] See EPA's voluntary diesel retrofit program Web site at *http://www.epa.gov/otaq/retrofit/overfleetowner.htm.*

[36] See EPA's voluntary diesel retrofit program Web site at *http://www.epa.gov/otaq/retrofit/idling.htm.*

[37] See EPA's Web site on transportation control measures at *http://www.epa.gov/otaq/transp/traqtcms.htm.*

[38] See EPA's Web site on nonroad engines, equipment, and vehicles at *http://www.epa.gov/otaq/nonroad.htm.*

[39] Fuels adopted in SIPs must be consistent with the Energy Policy Act of 2005 and EPA guidance on SIP-approved boutique fuels at 71 FR 78192 (December 28, 2006).

Menu of Options provide potentially useful ideas. Specifically, States would need to assess which items on the menu are applicable in their areas, and will have to assess the costs of applying controls locally. Accordingly, there would be ample opportunity for public review of the State's analysis of the local cost and air quality impacts of any measure listed in the document which is included in a State's SIP. The EPA is not requiring that States adhere to the list of measures in the *Menu of Options.* The EPA does not in any way mean to imply that the measures in the *Menu of Options* are presumed to be RACM, merely that they are potential controls for areas to consider. The *Menu of Options* has no regulatory significance and thus need not be issued through notice-and-comment rulemaking. The EPA notes, however, that the *Menu of Options* does provide a broad list of potential sources and measures that can help inform States in the development of their plans. Similarly, our own list of potential measures is not intended to be a categorical list of measures which States must adopt, rather it is intended to provide guidance about the types of sources and measures that States can consider in constructing their attainment plans. The EPA emphasizes that whether a source category or potential measure is or is not on this list is simply not conclusive as to whether a given measure is appropriate to consider in the RACT and RACM analysis. That can be determined only through the State's development of the attainment plan, and EPA's evaluation of such plan.

Comment: A commenter representing the paper industry interpreted the proposed rule as requiring electrostatic precipitator and tighter sulfur-in-fuel requirements for the forest products industry. The commenter believed that EPA was creating limits for such sources without adequate rulemaking process.

Response: The EPA disagrees that the listing of control technologies in the table in the rule creates a ''rebuttable presumption.'' Rather, the table identifies potential opportunities for emissions reductions which should be reviewed in light of technical and economic feasibility, and which a State should consider in a list of possible RACT and RACM measures for purposes of attaining the standards as expeditiously as practicable. The EPA is currently conducting a sector-based approach to the paper industry. One of the goals of the sector initiative on pulp and paper is to work with the industry to identify reductions in SO_2 and $PM_{2.5}$ that will assist us in meeting the NAAQS, considering facility locations, magnitude of emissions, emission stream characteristics, and cost effectiveness of controls.

Comment: A number of commenters believed that EPA should develop not only a list of measures to consider for RACM, but should develop a list of mandatory measures that States should include, particularly for areas with attainment dates more than 5 years after designation.

Response: See discussion in section II.D.3 regarding rule requirements for attainment date extensions and the issue of whether certain measures should be mandatory in order for an area to receive an extension.

Comment: Some commenters believed that the list of possible measures was deficient in not including sources of $PM_{2.5}$ and $PM_{2.5}$ precursors from agricultural sources. One commenter believed the list is incomplete without identifying the contribution of ammonia emissions associated with livestock, poultry, and crop fertilizers.

Response: As we indicated in the proposal, we included a list of potential RACM measures in the preamble to the proposed rule, based upon a review of information about the contribution of various sources to the emissions inventories and a review of potential control measures for such sources. We did not identify emissions from agricultural sources in this review. Because ammonia is not presumed to be a $PM_{2.5}$ precursor unless identified for a specific area by the State or EPA, regulation of ammonia emissions from agricultural sources may not be necessary.

We also note that the agricultural industry presents unique challenges to regulators given the nature of relevant emissions sources. Moreover, we currently lack good methods to quantify agricultural emissions, and we do not fully understand their contribution to nonattainment problems. We have entered into an agreement with several animal producer sectors to monitor animal feeding operations to develop better tools to assess emissions from this industry. Hopefully, these tools will enhance our knowledge of agricultural emissions and their contribution to nonattainment problems. Until emissions from these sources are better understood, States should be judicious in determining whether any specific measure is RACT/RACM for this industry.

The EPA recognizes that the United States Department of Agriculture (USDA) has been working with the agricultural community to develop conservation systems and activities to control coarse particle emissions. Based on current ambient monitoring information, these USDA-approved conservation systems and activities have proven to be effective in controlling these emissions in areas where coarse particles emitted from agricultural activities have been identified as a contributor to a violation of the PM_{10} NAAQS. The EPA has found that where USDA-approved conservation systems and activities have been implemented, these systems and activities have satisfied the Agency's reasonably available control measure and best available control measure requirements for areas needing to attain the PM_{10} standards.

The EPA believes that in the future, certain USDA-approved conservation systems and activities that reduce agricultural emissions of fine particles may be able to satisfy the requirements of applicable sources to implement reasonably available control measures for purposes of attaining the $PM_{2.5}$ NAAQS. The EPA will work with States to identify appropriate measures to meet their RACM requirements, including site-specific conservation systems and activities. The EPA will continue to work with USDA to prioritize the development of new conservation systems and activities; demonstrate and improve, where necessary, the control efficiencies of existing conservation systems and activities; and ensure that appropriate criteria are used for identifying the most effective application of conservation systems and activities.

Comment: Some commenters raised concerns about a statement in the proposal that ''[i]n addressing a nonattainment area having military training, testing and operational activities occurring within it, the State should not need to target these activities for emission reductions.'' Some commenters interpreted this statement as an exemption from any emission reduction requirements for military sources.

Response: The statement in the proposal was not intended as an exemption for all military activities. Emissions potentially contributing to $PM_{2.5}$ concentrations at military installations originate from a variety of sources: basic operational activities (such as power generation, other fuel combustion, and transportation to and from residences, offices, and schools); and from field training and testing activities (such as personnel training, obscurants used in training, operation of nonroad vehicles and equipment, and related prescribed burning operations). The EPA believes that in evaluating emissions for a specific nonattainment

area having military activities occurring within it, the State should consult with DOD for information on the nature of these activities and their associated emissions.

With regard to military training activities specifically, such activities are periodic in nature, and when they do occur, the principal type of emissions generated by these activities is dust (i.e. inorganic direct PM emissions) from field operations. Other pollutants may be emitted to a lesser degree from certain onroad and nonroad motor vehicles. While military training activities may contribute some degree of primary $PM_{2.5}$ emissions to certain nonattainment area inventories, the fugitive dust generated from military training activities is predominantly composed of coarse PM rather than fine PM.

Based on data from the $PM_{2.5}$ speciation monitoring network operated by EPA and the States, the contribution of inorganic dust to total $PM_{2.5}$ mass on an annual average basis is relatively low in most nonattainment areas, on the order of 0.5 to 1.5 micrograms per cubic meter (generally 10% or less of total $PM_{2.5}$ mass). Dust from military training activities would be a subset of these levels. Depending on the available information and specific circumstances for a particular area, a State could find in its SIP development analyses that direct $PM_{2.5}$ emissions from military training activities do not significantly contribute to $PM_{2.5}$ concentrations in the nonattainment area, and therefore would not need to target military training activities for emission reductions in its attainment plan.[40]

7. How Should States Consider EGU Reductions for CAIR in Meeting RACT/RACM Requirements?

a. Background

In section III.I.11 of the preamble to the proposed rule, we discussed the nature of the SO_2 and NO_X RACT obligations of electric generating unit (EGU) sources in states subject to the CAIR emission reduction requirements. The CAIR rulemaking was finalized in March 2005 and published at 70 FR 25221 (May 12, 2005). CAIR requires 28 states and the District of Columbia to significantly reduce emissions of SO_2 and/or NO_X. The 26 jurisdictions in the CAIR $PM_{2.5}$ region are required to reduce annual emissions of SO_2 and NO_X, and the 26 jurisdictions in the CAIR ozone region are required to reduce seasonal emissions of NO_X. These jurisdictions also have the option of participating in EPA-administered annual SO_2, annual NO_X, and seasonal NO_X cap-and-trade programs (the CAIR trading programs) to meet these emission reduction requirements. In addition, in March 2006, EPA promulgated a Federal implementation plan (FIP) to implement CAIR in these jurisdictions until they have EPA approved CAIR SIPs in place (71 FR 25328, April 28, 2006). The FIP adopts, as the control measure, the CAIR trading programs slightly modified to allow for Federal instead of State implementation. When fully implemented, CAIR will reduce SO_2 emissions in these jurisdictions by over 70 percent and NO_X emissions by over 60 percent from 2003 levels. This will result in $85 to $100 billion in health benefits and nearly $2 billion in visibility benefits per year by 2015 and will substantially reduce premature mortality in the eastern United States. The benefits will continue to grow over time as the program is fully implemented (i.e., the SO_2 emission bank is depleted and the final cap is met), and as growth in populations and the aging of the population continues (which increases the susceptible population).

Sources subject to cap-and-trade programs such as the CAIR trading programs generally have the option of installing emissions control technology, adopting some other strategy to reduce emissions, or purchasing emissions allowances and thereby effectively paying other sources covered by the cap to reduce emissions. In the proposal, we noted that a number of EGUs expected to be covered by the CAIR trading programs are located in nonattainment areas. Based on emissions projections for 2010 and 2015 using the Integrated Planning Model (IPM), some of these EGUs are expected to comply with CAIR by purchasing allowances under the trading program and some are expected to comply by installing emission controls.

The proposal also described our past experience with the implementation of the NO_X SIP Call and our belief that many power companies will develop their strategies for complying with CAIR based, in part, on consultations with State and local air quality officials in order to address local $PM_{2.5}$ and ozone attainment planning needs. The EPA suggested that consultations on location of CAIR controls would be timely during State development of the CAIR SIP, which is due in 2006, prior to the April 2008 deadline for submitting $PM_{2.5}$ nonattainment area SIPs.

The EPA proposed a determination that in States that fulfill their CAIR SO_2 emission reductions entirely through EGU emission reductions (i.e. without reductions from non-EGU sources or allowing non-EGU sources to opt-in to the CAIR SO_2 trading program), participation in the CAIR SO_2 trading program would satisfy the SO_2 RACT requirement for the EGU sources. The EPA also proposed that in states that fulfill their CAIR NO_X emission reductions entirely through EGU emission reductions, CAIR would satisfy NO_X RACT for the EGU sources, provided that those sources with existing selective catalytic reduction (SCR) emission control technology installed on their boilers operate that technology on a year-round basis beginning in 2009. Note that direct $PM_{2.5}$ emissions are not addressed by the CAIR program, and EPA did not propose any determination that compliance with CAIR would satisfy RACT for direct $PM_{2.5}$ emissions. The proposal included a discussion of the rationale for these proposed determinations for SO_2 and NO_X, and requested comments on the issue.

b. Final Rule

As discussed in section II.F.2 on our overall policy for RACT and RACM, we consider an area's obligation to implement RACT to be part of the area's overall RACM obligation—to adopt those reasonably available measures needed to reach $PM_{2.5}$ attainment as expeditiously as practicable. The final rule also reflects this combined RACT/RACM approach regarding EGU control obligations under CAIR and the extent to which meeting CAIR also satisfies a source's RACT and RACM requirements for attainment.

Specifically, the final rule includes a presumption that in States that fulfill their CAIR SO_2 emission reduction requirements entirely through EGU emission reductions (i.e. without reductions from non-EGU sources or allowing non-EGU sources to opt in to the CAIR SO_2 trading program), compliance by EGU sources with an EPA-approved CAIR SIP or a CAIR FIP would satisfy their SO_2 RACT/RACM requirements for attaining the fine particle NAAQS. This section also includes a presumption that in States

[40] Windblown dust from agricultural tilling activities also can be a periodic source of inorganic PM in some areas. In some cases such dust would be expected to be predominantly composed of coarse PM rather than fine PM. Depending on the available information and specific circumstances for a particular area, it is possible that a State could find in its SIP development analyses that direct $PM_{2.5}$ emissions from agricultural tilling activities do not significantly contribute to annual average $PM_{2.5}$ concentrations in the nonattainment area, and therefore would not need to require emission reductions from agricultural tilling activities in the plan for attaining the annual standard. However, States should be mindful of the contribution of these sources to 24-hour fine particle concentrations.

that are subject to CAIR annual NO_X emission reduction requirements and fulfill these requirements entirely through EGU emission reductions (i.e. without reductions from non-EGU sources or allowing non-EGU sources to opt in to the CAIR annual NO_X trading program), compliance by EGU sources with an EPA-approved CAIR SIP or a CAIR FIP would satisfy the NO_X RACT/RACM requirement for the $PM_{2.5}$ NAAQS, provided that the sources with existing selective catalytic reduction (SCR) emission control technology installed on their boilers operate that technology on a year-round basis beginning in 2009. This final position is based on a number of factors identified in the proposal and discussed below.

Many $PM_{2.5}$ nonattainment areas are projected to achieve significant SO_2 and NO_X reductions under the CAIR program. We do not believe that requiring source-specific RACT/RACM controls on specified EGUs in nonattainment areas would reduce total SO_2 and NO_X emissions from sources covered by CAIR below the regionwide levels that will be achieved under CAIR alone. Nor do we believe that ''beyond CAIR'' EGU controls for SO_2 and NO_X are ''reasonably available'' control measures for most areas within the CAIR Region. Accordingly, most States need not evaluate additional control measures on EGUs to satisfy RACT/RACM requirements as explained above.

As discussed previously, we are not requiring that States impose RACT on any specific size or type of source. Instead, States must conduct a RACT/RACM analysis considering measures that are ''reasonably available'' to meet the overarching requirement to attain the standards as expeditiously as practicable. Thus, the final rule imposes no specific requirement on States to impose RACT/RACM on EGUs.

Nonetheless, in evaluating RACT/RACM for EGUs, EPA believes it is appropriate for States (states that achieve all reductions from EGUs) to consider the special attributes of that group of facilities including the unique interrelated nature of the power supply network, and their participation in the CAIR program. For EGUs in the CAIR region, based upon the presumption explained here, States may define RACT/RACM as the CAIR level of control on the collective group of sources in the region rather than impose a specific level of control on an individual source. This approach is similar to the Agency's past ''bubble'' policy, as discussed in section (c) addressing comments on the proposal.

As discussed more fully in the CAIR final rulemaking notice, EPA has set the 2009 and 2010 CAIR caps for SO_2 and NO_X at a level that will require EGUs to install emission controls on the maximum total capacity on which it is feasible to install emission controls by those dates. The EPA concluded that the CAIR compliance dates represent an aggressive schedule that reflects the limitations of the labor pool, and equipment/vendor availability, and need for electrical generation reliability for installation of emission controls.

Although the actual SO_2 cap does not become effective until 2010, we designed banking provisions in CAIR so that covered EGUs will begin to reduce their SO_2 emissions almost immediately after CAIR is finalized, and will continue steadily to reduce their emissions in anticipation of the 2010 cap and the more stringent cap that becomes effective in 2015. The 2015 SO_2 and NO_X caps are specifically designed to eliminate all SO_2 and NO_X emissions from EGUs that are highly cost effective to control (the first caps represent an interim step toward that end).

Moreover, we predicted that the majority of large coal-fired utilities will install advanced control technologies under CAIR because the larger and higher emitting source offer an opportunity to obtain more cost-effective emissions reductions. We expect that the largest-emitting sources will be the first to install SO_2 and NO_X control technology and that such control technology will gradually be installed on progressively smaller-emitting sources until the ultimate cap is reached. As a result, few, if any coal-fired units with greater than 600 MW of operating capacity should operate in $PM_{2.5}$ nonattainment areas without advanced control after full implementation of CAIR. Of the remaining units operating without advanced pollution controls, a great many of these units will have operating capacities below 300 MW. We predict that these units ''will be utilized less often,'' and ''typically have baghouses and electrostatic precipitators for particulate control, have combustion controls for NO_X control, and burn low-sulfur coal.'' See ''Contributions of CAIR/CAMR/CAVR to NAAQS Attainment: Focus on Control Technologies and Emission Reductions in the Electric Power Sector,'' Office of Air and Radiation, U.S. Environmental Protection Agency, April 18, 2006 (available at *http://www.epa.gov/airmarkets/cair/analyses/naaqsattainment.pdf*). In light of these expected results, we generally believe that the cost to install additional controls on these smaller units would be unreasonable.

We are also concerned that if States require specific EGUs to install advanced pollution control measures, it could interfere with the market-based incentives inherent in the cap and trade program. This could increase the cost of compliance and shift the location of the units that would otherwise opt to install advanced emissions controls. Such a result may be counterproductive to that State's attainment efforts, as the State may forego a larger quantity of more beneficial reductions in transported pollutants, in exchange for a smaller quantity and less beneficial reduction in local emissions. Moreover, it may reduce the benefits expected in other nonattainment areas as well. Accordingly, even if a State found the cost to control an individual unit acceptable on a cost per ton basis, the potential overall disbenefit of control may nonetheless make imposition of the control not ''reasonably available.''

The EPA finds that the control installations projected to result from CAIR NO_X and SO_2 caps in 2009 and 2010 are as much as feasible from EGUS across the CAIR Region by those dates. In fact, if states chose to require smaller-emitting sources in nonattainment areas to meet source-specific RACT requirements by 2009, they would likely use labor and other resources that would otherwise be used for emission controls on larger sources. Because of economies of scale, more boiler-makers may be required per megawatt of power generation for smaller units than larger units. In this case, the imposition of source-specific RACT/RACM on smaller emitting sources by 2009 could actually reduce the amount of banking that would otherwise occur and result in higher SO_2 emissions in 2009 as compared to the level that would result from implementation of CAIR alone.

In any event, the imposition of source-specific control requirements on a limited number of sources also covered by a cap-and-trade program would not reduce the total regionwide emissions from sources subject to the program. Under a cap-and-trade program such as CAIR, a given number of allowances are issued in order to achieve a given emission level. Source-specific control requirements within the CAIR program may affect the temporal distribution of emissions (by reducing banking and thus delaying early reductions) or the spatial distribution of emissions (by moving them around from one place to another), but they would not affect total regional emissions under the program. If source-specific requirements were targeted at the units

that could be controlled most cost-effectively, then the imposition of source-specific controls would likely achieve the same result as the cap-and-trade program. If not, however, the imposition of source-specific requirements would make any given level of emission reduction more costly than it would be under the cap-and-trade program alone. Thus, the imposition of source-specific RACT on EGUs covered by CAIR would not reduce total regionwide emissions, but would likely achieve emission reductions under the program in a more costly way.

Given the considerations described above, we think that in many areas additional controls on EGUs generally would not be ''reasonably available.'' Notwithstanding these conclusions, we recognize that States are in the best position to determine how best to achieve attainment with the $PM_{2.5}$ NAAQS in light of local needs and conditions. As we acknowledged in our proposed rule, power plant operators typically have ongoing relationships with the State and local officials involved in air quality planning. We expect that power plants will continue to collaborate with State officials to determine how best to address multiple air quality goals, and which plant locations to control under CAIR, considering local $PM_{2.5}$ and ozone attainment needs.

The EPA expects States and local air agencies to identify reasonably available control measures that are necessary and reasonable to attain the standards as expeditiously as practicable; and that after consulting with power companies, the State may conclude that establishing additional ''beyond CAIR'' emission control requirements on specific sources in nonattainment areas is warranted to provide for attainment as expeditiously as practicable. Nevertheless, in preparing the overall attainment demonstration, States should be aware of the expected benefits of the market-based incentives of the CAIR program, the cost effectiveness of control, feasibility of implementation, and any disbenefits that would result from requiring ''beyond CAIR'' controls on any specific EGU before concluding that additional controls on EGUs are ''reasonably available'' and necessary to satisfy RACT/RACM requirements.

Year-round NO_X controls. In the CAIR final rulemaking notice, EPA found that the operation of existing SCRs on a year-round basis, instead of operating them only during the ozone season, could achieve NO_X reductions at low cost relative to other available NO_X controls. The EPA projected that power generators would employ this control measure to comply with CAIR SIPs. Based on this control opportunity, EPA estimated the average cost of non-ozone-season NO_X control at $500/ton. These considerations support a finding that RACT should include year-round operation of existing SCRs that are located in $PM_{2.5}$ nonattainment areas. Because all $PM_{2.5}$ nonattainment areas violate the annual form of the $PM_{2.5}$ standard and public health can be affected by high $PM_{2.5}$ levels in the winter as well as the summer, we believe that year-round operation of existing SCR that are located in nonattainment areas where NO_X is an attainment plan precursor will provide additional health benefits for relatively low dollar cost per ton of pollutant reduced.

In the proposal notice, EPA proposed to define ''existing'' SCRs as those units that were in place by the date of the proposed rule (November 1, 2005). We selected this date rather than the final date to avoid creating an incentive to delay installation of new SCR. Today, we finalize our proposed approach with one clarification. To avoid confusion over the proper interpretation of the phrase ''in place,'' we are clarifying that an existing SCR is one which is fully installed and capable of operation by November 1, 2005.

We also proposed that these existing SCR begin year-round operations no later than January 1, 2009 to qualify as RACT/RACM under our presumptive approach. We noted that year round operation of existing SCR involves little to no alteration of existing equipment, and that EGUs could conduct any required work during normal outages. Today, after taking these factors into account, we finalize our proposed rule. The year-round operation requirement, however, will not be federally enforceable to individual EGUs until EPA approves a State's SIP including the requirement.

c. Comments and Responses

Comment: Some commenters supported the proposed determination described in section (a) that in States that fulfill their CAIR SO_2 emission reduction requirements entirely through EGU emission reductions (i.e. without reductions from non-EGU sources or allowing non-EGU sources to opt in to the CAIR SO_2 trading program), compliance by EGU sources with an EPA-approved CAIR SIP or a CAIR FIP would satisfy the SO_2 RACT requirement for the sources; and in States that are subject to CAIR annual NO_X emission reduction requirements and fulfill these requirements entirely through EGU emission reductions (i.e. without reductions from non-EGU sources or allowing non-EGU sources to opt in to the CAIR annual NO_X trading program), compliance by EGU sources with an EPA-approved CAIR SIP or a CAIR FIP would satisfy the NO_X RACT requirement for the sources, provided that the sources with existing selective catalytic reduction (SCR) emission control technology installed on their boilers operate that technology on a year-round basis beginning in 2009. One commenter supported EPA's approach so long as States may pursue additional reductions from EGUs if needed for attainment as expeditiously as practicable. A number of other commenters opposed the proposed determination regarding RACT for EGUs based on a number of issues.

Response: Based on the rationale described in the sections above, the final rule includes a presumption that compliance with CAIR satisfies SO_2 and NO_X RACT/RACM requirements for EGUs in many areas. Nonetheless, States can require ''beyond CAIR'' EGU controls if a State determines that it is a necessary and reasonable means to attain the $PM_{2.5}$ standards. Comments opposing this approach are addressed in more detail below.

Comment: A number of commenters objected to the proposed determination, arguing that it would result in greater control requirements and economic burden on non-EGU sources located in nonattainment areas. These commenters urged EPA to adopt a final rule that provides for implementing the most cost-effective controls necessary to attain the standard. They assert that with the proposed finding that compliance with CAIR satisfies RACT for EGUs, the proposed rule would not provide for the most cost-effective approach to attainment. They argue EPA and States should develop cost-effectiveness guidance that includes all stationary source control measures and they should develop SIPs based on the most economic means to attain the standard. They make several arguments to support this position. The commenters asserted that if an EGU control is more cost-effective than a non-EGU control, the EGU should be subject to ''beyond-CAIR'' controls. They also asserted that if EPA chooses to consider the CAIR rule as satisfying SO_2 and NO_X RACT for EGUs, then other sources should not be subjected to control costs greater than those found reasonable under CAIR (i.e., $800/ton). They believe it would be inequitable to require smaller sources to pay a higher cost for emissions reductions than larger sources, which are a more significant

contributor to the problem and which may be able to make more cost-effective emission reductions. One commenter also suggested that EPA should authorize a presumption that emissions reductions required on electric utilities under the CAIR will be equivalent to RACT only if a particular source in a CAIR State has installed controls that achieve the average level of control that EPA has projected will occur for the particular pollutant under the CAIR requirements.

Response: The EPA has determined that implementation of the CAIR trading program represents highly cost-effective controls that will achieve widespread regional SO_2 and NO_X emissions reductions from EGUs and will provide significant air quality benefits for ozone and $PM_{2.5}$ nonattainment areas. In developing attainment SIPs and identifying RACM, States will need to consider additional cost-effective and reasonable controls to reach attainment as expeditiously as practicable. The EPA does not agree with the commenter's argument that controls on non-EGUs should be no more than the projected cost of EGU controls under CAIR. The EPA expects that in order to achieve attainment as expeditiously as practicable, some States may need to adopt control measures for some sources which cost more per ton but which still are considered to be reasonable and cost-effective.

In addition, States must consider the economic feasibility of implementing a given control measure. Because of facility-specific factors, EPA believes it would be inappropriate to establish a threshold of control effectiveness (e.g. dollars per ton) based on control of EGUs and apply this threshold to all source categories. The ability of a source to cost-effectively reduce emissions is dependent on case-specific factors, including the ability of the given source to sustain the cost of control, and prevailing costs in the specific geographical location. A direct correlation between the size of an emissions source and the economic feasibility of controls for that source and location does not necessarily exist.

We also disagree with the commenter who suggests that RACT requirements should only be satisfied if a source achieves an average level of control that EPA projects to occur under CAIR. The EPA maintains that the presumption that CAIR satisfies SO_2 and NO_X RACT/RACM for EGUs in most areas is an appropriate policy. As discussed further below, we have always recognized that States could determine RACT for a single source or group of sources.

Comment: A number of commenters opposed the proposed determination that CAIR would satisfy the SO_2 and NO_X RACT requirement for EGUs. The commenters argued that this determination is unlawful, that it does not comply with section 172(c)(1) of the CAA which requires RACT (i.e. controls that are technologically and economically feasible) ''at a minimum'' for all existing sources in the nonattainment area, that it would allow very large stationary sources to escape cost-effective controls entirely, and that it is largely based on the legally-irrelevant contention that CAIR will reduce emissions more cost-effectively than RACT. They claim that EPA has no authority to displace the Congressionally-mandated RACT requirement, that CAIR was designed to address regional pollution transport (not to be an attainment strategy), and that EPA should remove these proposed provisions in the final rule. Commenters claim that the EPA's proposed approach to allow EGU emissions to be addressed solely through CAIR would undermine states' efforts to meet the Federal $PM_{2.5}$ health standard, particularly when EGU sources are among the most cost-effective to control. Another commenter claimed that EPA's proposal allowing States that choose to fulfill their CAIR requirements entirely through emission reductions from EGUs to also use CAIR to satisfy their SO_2 and NO_X $PM_{2.5}$ RACT requirements, thereby equating these two requirements for the EGU sector, is flawed. This commenter argued that allowing a cap-and-trade program, such as the CAIR, to substitute for the RACT requirement undermines the effectiveness of the controls by allowing facilities to use allowances to offset emissions, rather than control them at the source. The purchase of allowances, they assert, does not satisfy RACT requirements.

Response: The EPA disagrees with these comments. The final rule does not displace the RACT requirement for any sources. Instead, EPA is exercising its authority to interpret the section 172 RACT and RACM requirements for the purposes of implementing the 1997 $PM_{2.5}$ standards. For the reasons described in section (b) above, we believe that States can rely on EPA's presumption that compliance with a CAIR SIP or FIP, meeting certain requirements, will satisfy the RACT/RACM requirement for certain EGU sources. The EPA historically issued control technology guidelines setting forth presumptive levels of emissions control that satisfy the RACT requirement for a given industry. The final rule is similar to this practice in establishing a presumption that SO_2 and NO_X reductions under the CAIR program satisfy the RACT/RACM requirement for EGUs in CAIR States. In identifying reasonably available control measures to ensure attainment as expeditiously as practicable, States will need to take CAIR reductions into account as well as any additional cost-effective reductions that are technologically and reasonably available.

We further find that the attempt by many commenters to characterize CAIR as a strategy to address only regional pollution transport and not an attainment strategy as overly simplistic. The EPA analyses for CAIR show that there are significant air quality benefits projected for individual nonattainment areas as a result of SO_2 and NO_X reductions across the multistate CAIR region. The Act does not prevent States from properly crediting measures that achieve multiple objectives (e.g. regional transport or local nonattainment). Moreover, Section 110(a)(2)(D) requires SIPs to contain adequate provisions to assure that sources in the State do not contribute significantly to nonattainment in any other State. The CAIR rule is an integral element in meeting the States' Section 110 attainment obligations. Accordingly, it is reasonable to incorporate this consideration in determining what measures qualify as RACT/RACM.

Finally, EPA does not interpret the provisions of Section 172(c)(1) related to the RACT requirement as precluding States' use of a cap and trade approach as a means of regulating existing sources and achieving RACT/RACM reductions, especially in light of Congresses' expressed authorization to auction emission rights in Section 172(c)(6).

The EPA has long recognized that RACT need not apply to individual sources. As stated earlier, our early guidance on RACT requirements stated that States could establish RACT for an ''individual sources or *a group of sources.*'' (emphasis added) See Memo. Strelow (Dec. 1976) and 44 FR 71779. Importantly, Congress ratified the early interpretations of RACT and RACM when it enacted the 1990 Amendments. See 42 U.S.C. Section 7515 (Clean Air Act section 193). Our 1986 emissions trading policy also recognized a number of advantages offered through application of a ''bubble'' approach including faster compliance with RACT limits and earlier reductions. Moreover, Courts have upheld EPA's approval of States' use of ''bubbling'' multiple units to meet RACT requirements. See e.g.

Natural Resources Defense Council v. *EPA*, 941 F.2d 1207 (finding that EPA need not adhere to a source specific RACT determination to satisfy RACT requirements and acknowledging EPA's special knowledge and expertise in the area.)

Comment: The EPA's proposal to allow EGU emissions to be addressed solely through CAIR undermines prospectively States' efforts to meet the Federal $PM_{2.5}$ health standard. EGU sources are among the most cost-effective to control.

Response: For the reasons described in section (b) above, EPA believes that States can rely on EPA's presumption that compliance with a CAIR SIP or FIP, meeting certain requirements, satisfies the SO_2 and NO_X RACT/RACM requirement for certain EGU sources. Areas can require ''beyond CAIR'' EGU controls if a State determines that it is a necessary and reasonable means to attain as expeditiously as practicable. Nonetheless, as discussed above, EPA believes that implementation of the CAIR requirements will provide for substantial progress in attaining the $PM_{2.5}$ standards and that States may presume that RACT/RACM requirements are equal to the CAIR level of control.

Comment: CAIR fails to address the need for short-term reductions in $PM_{2.5}$ and precursor emissions on high pollution days. While RACT restricts emissions over a 1-hour to 24-hour period, CAIR only provides for an annual or seasonal cap. Reliance on CAIR therefore fails to recognize the importance of reducing short-term emissions, which was recently highlighted by the EPA's own proposal to tighten the 24-hour $PM_{2.5}$ health standard. Local and short-term adverse air quality effects of $PM_{2.5}$, must be addressed in the final rule by requiring RACT for all major facilities in addition to CAIR.

Response: The CAIR program is oriented toward reducing SO_2 and NO_X emissions in order to reduce air quality concentrations on an annual and seasonal basis. Because all $PM_{2.5}$ nonattainment areas were designated due to violations of the annual standard (and the two designated areas in California also violated the 24-hour standard), the focus of this implementation rule is attainment of the annual standard. CAIR is projected to provide significant air quality benefits in 2010 and 2015 for eastern $PM_{2.5}$ nonattainment areas on both an annual basis and on a 98th percentile 24-hour basis.[41]

Comment: The proposal is silent on the issue of whether EGUs are subject to direct $PM_{2.5}$ emissions RACT requirements. It is critical that RACT be required for all facilities with respect direct $PM_{2.5}$ emissions, regardless of a facility's participation in CAIR.

Response: In the final rule and preamble, EPA has clarified that all EGUs in nonattainment areas are subject to RACT/RACM for direct $PM_{2.5}$ emissions. The presumption described above applies only to SO_2 and NO_X RACT/RACM, not RACT/RACM for direct $PM_{2.5}$ emissions from EGUs.

Comment: The EPA fails to consider the geographical distributional impacts of the emission reductions. Equating CAIR with RACT fails to take into account the substantial contribution that emissions from EGUs within a nonattainment area may make toward that area's $PM_{2.5}$ nonattainment problem. The EPA does not attempt to explain how such a generalized determination satisfies RACT for $PM_{2.5}$.

Response: The establishment of recommended levels for RACT/RACM is an area Congress delegated to the specific expertise of the Agency. Based on our analysis, we conclude that the CAIR emissions caps presumptively represent the level of emissions control achievable through application of ''reasonably available'' control technologies. Nonetheless, in developing attainment plans, each State will evaluate the impact of stationary sources located within the nonattainment area in developing its attainment strategies for the local area.

Comment: A few commenters stated that EPA should explain how this proposal would be implemented for States that request an extension of an attainment date because attaining in 5 years or less is impracticable; i.e., whether EPA would still hold to its interpretation that CAIR equals RACT for EGUs and not require additional reductions from EGUs even if an area cannot attain in 5 years and controls on EGUs could lead it to attain more expeditiously. These commenters argue that, in considering if additional RACT is needed in states that obtain extensions of the attainment deadline after 2010, EPA cannot ignore potential RACT for electric generating units any more than they would be allowed legally to avoid consideration of any other RACT candidates. One commenter is particularly concerned that States would not include EGUs in their RACT determinations and instead require smaller industrial boilers or process heaters to control emissions.

Response: The EPA's determination regarding CAIR and RACT is not limited to areas attaining within five years. The Agency's rationale is presented in the ''final rule'' section above. We disagree that the CAIR–RACT presumptions necessarily shift emission control burdens from EGUs to smaller industry boilers and process heaters because, in implementing the RACM requirement, the State may include an evaluation of control options on those sources as part of their RACT/RACM analyses. As stated above, EPA concluded that the CAIR compliance dates represent an aggressive schedule that reflects the limitations of the labor pool, and equipment/vendor availability, and need for electrical generation reliability for installation of emission controls. Accordingly, additional controls on EGUs may not be a reasonably available control measure that can be effectively implemented in a manner that advances an area's attainment date.

Comment: The EPA designated many partial counties nonattainment for $PM_{2.5}$ solely because the areas contained EGU emission sources thought to cause or contribute to violations of the NAAQS. In implementing attainment plans, it makes sense to consider further control of these sources, and because they are located in nonattainment areas, the ability to do so is provided for and legal under the CAA.

Response: The EPA designated $PM_{2.5}$ nonattainment counties because they either had a violating monitor or they contributed to a nearby air quality problem. Importantly, EPA designated these areas without considering the air quality benefits expected in the future from CAIR. Accordingly, the fact that an EGU is located in a partial county and we included the partial county in the nonattainment area because we believe that the EGU was causing or contributing to the nonattainment violations, does not equate with a finding that more than CAIR is required to remedy the nonattainment problem. Nonetheless, EPA believes that States should evaluate the impact of stationary sources in all designated counties, including those partial counties noted by the commenter, in its assessment of reasonably available control strategies to ensure attainment as expeditiously as practicable.

Comment: The EPA should adopt the Ozone Transport Commission's (OTC's) approach to cap-and-trade programs. When the OTC developed its NO_X

[41] See the regulatory impact analysis chapter on air quality for the 2006 PM NAAQS review at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%204-Air%20Quality.pdf*.

Budget Program (which was the basis for EPA's NO_X SIP call and subsequently CAIR), it assumed that RACT was applied first. Thus the cap-and-trade program operated in an environment that assumed RACT was in force, not in lieu of RACT.

Response: Under the ozone national ambient air quality standards, NO_X and VOC RACT have been implemented progressively for the past 30 years or more, prior to development of the NO_X SIP call regional control program. In contrast, the $PM_{2.5}$ implementation program is the first instance in which we have required RACT/RACM specifically for fine particle pollution. For this reason, the CAIR program is not operating with SO_2 and NO_X RACT limits already in place for attainment of the $PM_{2.5}$ standards. Nonetheless, as discussed above, EPA believes that implementation of the CAIR requirements will provide for substantial progress in attaining the $PM_{2.5}$ standards and that States may presume that RACT/RACM requirements are equal to the CAIR level of control.

Comment: A few commenters stated that EPA should clarify and modify the part of its proposal that explains why a State cannot rely on EPA's determination that CAIR can satisfy the NO_X RACT requirement for $PM_{2.5}$ if the State ''elect[s] to allow non-EGU sources to voluntarily enter the EPA-administered CAIR trading program through an opt-in provision in the CAIR model rule.'' (70 FR 66025 col. 3). These commenters believe that this part of the proposal might be construed to preclude States subject to both the NO_X SIP Call and included in the CAIR region for ozone from relying on the NO_X RACT determination for $PM_{2.5}$ if the States choose ''to bring their non-CAIR [including non-EGU] NO_X SIP Call trading sources into the CAIR ozone season NO_X cap and trade program.'' (70 FR 49708, 49728 col. 3) (August 24, 2005). The commenters assert that EPA gave States the option of bringing non-EGU NO_X SIP Call sources into the CAIR seasonal NO_X trading program to ensure that non-CAIR sources, including non-EGUs, that are subject to the NO_X SIP Call rule would not be ''stranded,'' starting in 2009, by being left in an ozone season NO_X control program with no EGU trading partners. The commenters argued that ''EGUs should not be penalized, in the form of denial of CAIR–RACT treatment, as a result of States exercising their option to avoid financial and compliance difficulties for non-EGUs that otherwise would be left without allowance trading partners in the EGU sector after the NO_X SIP Call trading program ends in 2008.'' These commenters point to EPA's determination in the final Phase 2 ozone implementation rule, that participation in the CAIR trading programs can satisfy NO_X RACT for ozone even if a State brings non-EGUs in the NO_X SIP Call trading program into the trading program after 2008, *see* 70 FR 71657 col. 2, provided the State retains an ''EGU [emission] budget under CAIR that is at least as restrictive as the EGU budget that was set in the State's NO_X SIP call SIP,'' id. At 71658 col. 1. These commenters argue that EPA should make a similar determination here regarding NO_X RACT for purposes of $PM_{2.5}$ NAAQS implementation.

Response: All states with EPA approved CAIR SIPs or subject to a CAIR FIP implementing the annual NO_X emission reduction requirements, and obtaining those reductions solely from EGUs may rely on EPA's determination that CAIR presumptively satisfies NO_X RACT/RACM for $PM_{2.5}$ for these sources. This determination is unaffected by whether or not a State permits NO_X SIP Call non-EGUs to participate in the CAIR ozone season trading program. In the final rule, we have included the presumption that NO_X RACT/RACM for $PM_{2.5}$ is satisfied for EGUs complying with a CAIR SIP or CAIR FIP implementing the annual CAIR NO_X emission reduction requirements (provided the State implementation of the CAIR NO_X annual trading program includes EGUs only).[42]

In the final ozone implementation rule, EPA addressed numerous issues relating to the transition from the NO_X SIP Call to the CAIR ozone season trading program, including the impact of bringing NO_X SIP Call non-EGUs into the CAIR ozone season trading program. Commenters' suggestion that these determinations are relevant to this $PM_{2.5}$ implementation rule ignores the fact that both the NO_X SIP Call and the CAIR ozone season trading program are seasonal, not annual, trading programs. The NO_X SIP Call EGU and non-EGU budgets are seasonal NO_X budgets and do not address annual NO_X emissions. As discussed above, $PM_{2.5}$ levels year-round contribute to an area's annual average concentration, and NO_X emissions during non-summer months contribute to nitrate concentrations, which are typically highest in cooler temperatures. For these reasons, EPA believes it would be inappropriate to accept commenters' suggestion.

8. What Are the Required Dates for Submission and Implementation of RACT?

a. Background

The EPA requested comment on a general approach for the dates for submission and implementation of RACT rules. The final rule retains the proposed approach, as described in the following section.

b. Final Rule

The final rule requires the following:

(1) Date of submission. States must submit adopted RACT rules to EPA within 3 years of designation, at the same time as the attainment demonstration due in April 2008.

(2) Dates for implementation of control measures. States should also implement any measures determined to be RACT expeditiously, as required by section 172. Implementation of RACT measures should in no case start later than the beginning of the year before the nominal attainment date. For example, if an area has an attainment date of April 2010, then any required RACT measures should be in place and operating no later than the beginning of 2009. This is intended to help provide for clean air in calendar year 2009. As discussed in section II.D, if other criteria are also met, EPA could then grant the area a 1-year attainment date extension if the air quality level in the 3rd of the 3 years was below the level of the standard. If the area observes a second year of clean air, EPA could grant a second 1-year attainment date extension. In this case, the 2009 to 2011 period would then be reviewed to assess whether the area attains the standards.

(3) Provisions for a demonstration that additional time is needed. While EPA expects that States will implement required RACT controls by January 2009 in most situations, there may be cases where additional time is needed to implement an innovative control measure or to achieve a greater level of reduction through a phased approach. If a State has provided an adequate demonstration showing that an attainment date extension would be appropriate for an area, then the State may consider phasing-in certain RACT controls after January 2009. The EPA would allow the implementation of selected RACT controls after January 2009 if the State can show why additional time is needed for

[42] EPA's CAIR–RACT presumption also would not apply if a State required sources other than EGUs to achieve a portion of the reductions required by CAIR (e.g., the State's CAIR SIP achieved some reductions from EGUs but took credit for non-EGU reductions achieved under new, more stringent requirements implemented to meet NO_X SIP call caps). Under the CAIR rule such a State would not be eligible to participate in the EPA-administered CAIR trading system.

implementation, and such delayed implementation still would need to be on a schedule that provides for expeditious attainment. In no event could the State wait to implement RACT controls until the last few years prior to the attainment date without an adequate rationale for why earlier implementation was not feasible.

c. Comments and Responses

Comment: One commenter supported EPA's position that implementation of RACT and RACM by January 1, 2009 is necessary to achieve the effect on air quality for calendar year 2009.

Response: The EPA agrees with this comment.

Comment: Some commenters supported allowing for an implementation schedule that allowed for implementation of RACT and RACM for a time frame extending beyond 2009. These commenters favored such an approach if States provided an adequate demonstration of why the measures cannot be implemented earlier. Commenters noted that a phased approach to emissions reductions in some cases could lead to additional reductions that could not occur by 2009.

Response: The EPA agrees with these comments.

Comment: One commenter believed that so long as a State demonstrates attainment by 2015, EPA should not require implementation of any RACT measures. The commenter further asserted that it would be bad policy to require costly emissions reductions through imposition of RACT on areas expected to attain the standards through other means by 2015.

Response: The EPA disagrees with this comment. The CAA requires States to demonstrate that the attainment plan will attain the standards as expeditiously as practicable and must include RACT and RACM. The requirement for ''reasonable'' measures does not require that any theoretical measure be implemented, but does require implementation of those reasonable measures which could advance the attainment date by at least 1 year. Given the health effects associated with $PM_{2.5}$, EPA believes this approach is sound public policy.

9. Which Pollutants Must Be Addressed by States in Establishing RACT and RACM Limits in Their $PM_{2.5}$ Attainment Plans?

a. Background

In the proposed rule, and in the final rule as discussed in detail in section II.A above, EPA discusses the pollutants which States must address in the attainment plans, in particular with respect to RACT, RACM and NSR. These pollutants include not only direct $PM_{2.5}$, but also gaseous precursors to the formation of $PM_{2.5}$. In general, the decisions that States and EPA make with respect to which precursors are significant contributors to an area's $PM_{2.5}$ nonattainment problem define the pollutants and sources to be addressed by States in developing RACT and RACM.

b. Final Rule

In the final rule, in establishing RACT and RACM limits, those RACT and RACM limits must address:

—Direct emissions of $PM_{2.5}$
—SO_2, a precursor to $PM_{2.5}$ formation, and
—NO_X, unless a State makes a finding that NO_X emissions from sources in the State do not significantly contribute to the $PM_{2.5}$ problem in a given nonattainment area.

The EPA generally presumes that RACT and RACM limits are not needed for ammonia or VOC unless that State or EPA determines otherwise for a given nonattainment area. RACT and RACM limits are needed for ammonia if a State or EPA makes a finding that ammonia emissions significantly contribute to the $PM_{2.5}$ problem in a given nonattainment area, and thus finds that control of ammonia would help address the $PM_{2.5}$ problem. RACT and RACM limits are needed for VOC only if a State or EPA makes a finding that VOC emissions significantly contribute to the $PM_{2.5}$ problem in a given nonattainment area. (As a point of clarification, ''VOCs,'' which are gaseous organic precursors to the chemical formation of secondary organic aerosol, are treated differently from semivolatile or nonvolatile organic compounds which are addressed as directly emitted $PM_{2.5}$). Issues related to the finding of ''significant contribution'' for these pollutants are discussed in Section II.A above.

10. Under the $PM_{2.5}$ Implementation Program, When Does a State Need To Conduct a RACT Determination for an Applicable Source That Already Has a RACT, BACT, LAER, or MACT Determination in Effect?

a. Background

For $PM_{2.5}$ nonattainment areas, States are required to implement the RACT requirement to reduce emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors from applicable sources. The EPA anticipates that for some sources located in $PM_{2.5}$ nonattainment areas, the State would have previously conducted RACT determinations for VOC or NO_X under the 1-hour ozone standard, or for direct PM_{10} emissions under the PM_{10} standards. Some of the RACT determinations established under these other programs would be relatively recent while other determinations may be more than 10 years old. In some cases, a new RACT determination might reach the conclusion that the preexisting determination is still valid and would require the installation of similar control technology because the relevant pollutant was addressed, the same emission points were reviewed, and the same fundamental control techniques would still have similar costs. In other cases, however, a new RACT analysis could determine, for example, that better technology has become available, and that cost-effective emission reductions are achievable.

In the proposed rule, the EPA requested comments on a general approach to taking prior RACT determinations into account, and within the general approach, invited comments on two specific questions: (1) Should new RACT determinations be required for all existing determinations that are older than a specified amount of time (such as 10 years old)?; and (2) what supporting information should a State be required to submit as part of its certification to demonstrate that a previous RACT analysis meets the RACT requirement currently for purposes of the $PM_{2.5}$ program?

In the proposed rule, EPA also noted that sources subject to RACT may also have been subject to other prior technology determinations such as BACT, LAER or MACT determinations. The proposed rule requested comment on approaches to taking these prior technology determinations into account.

b. Final Rule

The EPA has determined that it is appropriate to follow the approach in the proposed rule, which is described below. State RACT SIPs for $PM_{2.5}$ must assure that RACT is met, either through a new RACT determination or a certification that previously required RACT controls represent RACT for $PM_{2.5}$.

Where a State adopted and EPA approved a control measure as RACT for a pollutant emitted from a specific stationary source or source category under another NAAQS program, the State may submit as part of its SIP revision a certification, with appropriate supporting information, that the previous determination represents a current RACT level of control for those emissions for purposes of the $PM_{2.5}$ program. Otherwise, the State should revise the SIP to reflect a modified

RACT requirement for specific sources or source categories.

In cases where the State's prior RACT analysis under another NAAQS program concluded that no additional controls were necessary, a new RACT determination is required for that source. In cases where the previous RACT determination did not require any controls on the source, it is more likely that a new review might find that emission controls are now economically and technically feasible. This is because emissions reductions from a potential control measure are likely to be greater, and the cost per ton of emission reduction is likely to be lower, than in the case of a source that previously installed controls to meet RACT under another program.

A RACT determination for a source or source category subject to a prior RACT determination is also required for any pollutants that were not the subject of the prior RACT determination, but which the State has determined should be regulated for purposes of $PM_{2.5}$. The EPA advises that the State should closely review any existing RACT determinations established under another NAAQS program. For RACT certifications and determinations, States are to consider new information that has become available since the earlier RACT determination. For example, where updated information on control technologies is presented as part of notice-and-comment rulemaking, including a RACT SIP submittal for sources previously controlled, States (and EPA) must consider the additional information as part of that rulemaking. Existing EPA guidance on control technologies can be used to help inform RACT decisions. However, EPA believes it may not be sufficient for a State to rely on technology guidance that is several years old and issued to provide recommendations on control measures and levels for a different NAAQS in evaluating RACT for $PM_{2.5}$.

With respect to prior technology determinations other than RACT, the final rule provides that:

(1) Prior BACT and LAER Determinations. In many cases, but not all, best available retrofit technology (BACT) or lowest achievable emission rate (LAER) provisions for new sources would assure at least RACT level controls on such sources. The BACT/LAER analyses do not automatically ensure compliance with RACT since the regulated pollutant or source applicability may differ and the analyses may be conducted many years apart. States may, however, rely on information gathered from prior BACT or LAER analyses for the purposes of showing that a source has met RACT to the extent the information remains valid. We believe that the same logic holds true for emissions standards for municipal waste incinerators under CAA section 111(d) and NSR/PSD settlement agreements. Where the State is relying on these standards to represent a RACT level of control, the State should present its analysis with its determination during the SIP adoption process.

(2) Compliance With MACT Standards Affecting VOC. In situations where the State has determined VOC to be a significant contributor to $PM_{2.5}$ formation in an area, compliance with MACT standards may be considered in VOC RACT determinations. For VOC sources subject to MACT standards, States may streamline their RACT analysis by including a discussion of the MACT controls and relevant factors such as whether VOCs are well controlled under the relevant MACT air toxics standard, which units at the facility have MACT controls, and whether any major new developments in technologies or costs have occurred subsequent to establishment of the MACT standards. We believe that there are many VOC sources that are well controlled (e.g., through add-on controls or through substitution of non-VOC non-HAP materials for VOC HAP materials) because they are regulated by the MACT standards, which EPA developed under CAA section 112. Any source subject to MACT standards must meet a level that is as stringent as the best-controlled 12 percent of sources in the industry. Examples of these HAP sources that may effectively control VOC emissions include organic chemical plants subject to the hazardous organic NESHAP (HON), pharmaceutical production facilities, and petroleum refineries.[43] We believe that, in many cases, it will be unlikely that States will identify VOC emission controls more stringent than the MACT standards that are not prohibitively expensive and are thus unreasonable. We noted our view that this will allow States, in many cases, to conclude that the control measures implemented to meet MACT standards satisfy any requirement for VOC RACT.

(3) Compliance With MACT Standards Affecting $PM_{2.5}$ Emissions. Compliance with MACT standards may be considered in direct $PM_{2.5}$ RACT determinations. For direct $PM_{2.5}$ sources subject to MACT standards, States may streamline their RACT analysis by including a discussion of the MACT controls and relevant factors such as whether $PM_{2.5}$ emissions are well controlled under the relevant MACT air toxics standard, which units at the facility have MACT controls, and whether any major new developments in technologies or costs have occurred subsequent to the MACT standards. We believe that there are many direct $PM_{2.5}$ sources that are well controlled (e.g., through add-on controls that represent state-of-the-art measures for $PM_{2.5}$ reduction) because they are regulated by the MACT standards which EPA developed under CAA section 112. For some MACT standards, $PM_{2.5}$ is used as a surrogate for achieving MACT for HAPs such as heavy metals. Any source subject to MACT standards must meet a level that is as stringent as the best-controlled 12 percent of sources in the industry. We believe that there will be sources for which it will be unlikely that States will identify emission controls more stringent than the MACT standards that are not prohibitively expensive and are thus unreasonable. In addressing whether a MACT standard represents best controls for $PM_{2.5}$, it is important that the State consider all $PM_{2.5}$ sources at a given facility and the nature of the PM limit (i.e., whether the limit ensures control of the fine fraction of particulate matter). Also, the State should evaluate the degree of capture of $PM_{2.5}$—that is, the amount of $PM_{2.5}$ that is collected and sent to a pollution control device in addition to the efficiency of the device itself. This evaluation should consider the $PM_{2.5}$ emissions reductions that could be achieved by improving the degree of capture.

(4) Year-Round Controls for NO_X. In some cases, sources subject to NO_X RACT for PM will also be subject to controls under the NO_X SIP Call. In the 8-hour ozone implementation rule, EPA concluded that certain sources which have installed emission controls to comply with the NO_X SIP call would be deemed to meet NO_X RACT for the purposes of the 8-hour ozone implementation program. Some of these sources subject to the NO_X SIP call may choose to control NO_X emissions only or primarily during the ozone season. For purposes of $PM_{2.5}$, however, EPA concludes that the operation of emission controls only or primarily during the ozone season would not constitute RACT for $PM_{2.5}$ purposes. Indeed $PM_{2.5}$ control programs must address annual average concentrations, and in many

[43] There are some MACT categories for which it may not be possible to determine the degree of VOC reductions from the MACT standard without additional analysis; for example, the miscellaneous metal parts and products (40 CFR part 60, subpart MMMM) due to the uncertainty of the compliance method that will be selected.

areas nitrate concentrations are generally highest in the winter. Therefore, RACT for $PM_{2.5}$ is year-round operation of controls. For sources subject to both the NO_X SIP call and NO_X RACT for PM, we believe that, in most cases, the additional costs of running the NO_X SIP call controls year-round would impose only modest, reasonable additional costs and the cost effectiveness would be better than the average cost effectiveness for many other sources subject to PM RACT. (See further discussion in section F.7 above related to EGU sources subject to CAIR requirements for NO_X).

c. Comments and Responses

Comments: A number of commenters agreed with the requirement for the State to conduct a new RACT determination for any source for which the State's prior RACT analysis under another NAAQS program concluded that RACT was defined as no additional controls. One commenter noted that for a source having a previous RACT determination for ozone or PM_{10} to show that its level of control currently meets RACT for $PM_{2.5}$ purposes, the source must provide supporting documentation showing that the previous RACT determination was based on the same universe of controls that are ''reasonably available'' for the source in the present day.

Response: The EPA agrees with these comments.

Comments: A few commenters recommended that EPA clarify that RACT determinations resulting only in ''operational changes'' should be treated in an equivalent manner as those resulting in no controls. The commenters suggested that, unlike ''physical modification,'' such operational changes should always be revisited with a new RACT determination.

Response: The EPA does not agree with the implicit recommendation to impose different RACT review requirements based on the types of control previously implemented. The EPA believes that a reassessment of RACT is warranted, irrespective of the type of control previously implemented, to consider the reasonableness of modifying or adding controls in the particular circumstances. Furthermore, we are concerned that making such a distinction based upon the fairly broad term ''operational change'' would be difficult to interpret and implement, and would invite unnecessary disputes concerning the application of the term.

Comment: Commenters differed on whether new RACT determinations should be required for all existing determinations made before a specific date, and on what that date should be. Some commenters recommended that EPA allow States to rely on any previous RACT determinations made after 1990, and one commenter recommended that EPA require States to review only those older than 10–15 years, another recommended 10 years. One commenter believed that a 15-year period would be reasonable where previous controls were installed, to allow for a 15-year amortization of the cost of those controls. Other commenters recommended that new RACT determinations be made for any RACT determinations older than 5 years. Another commenter recommended that all RACT determinations should be reviewed.

Response: The EPA has not included any specific time frame in the final rule. The EPA agrees that the more recent the RACT determination, the greater the probability that technology advances or decreases in control cost will not have occurred. At the same time, technology advances and decreases in control cost can and have occurred frequently. Accordingly, we believe it is necessary for States to review whether such technology advances or decreases in control cost have occurred before relying on previous RACT determinations. We do not believe there is any specific date or age that could be identified after which States could ensure that no technology advances or decreases in control cost will have occurred.

Comment: A number of commenters expressed concerns with the resources required to conduct the certifications required by the proposed approach, and argued that expending the resources required to review and to certify previous RACT determinations would not be productive. One commenter recommended that EPA provide guidance on the previous RACT categories for which old RACT determinations are believed to be out of date. Another commenter asserted that the only possible exception to the acceptability of previous RACT measures for purposes of the ozone standards would be when the new RACT is year-round for an existing ozone-season RACT measure.

Response: The EPA believes that the proposed certification approach strikes an appropriate balance in requiring States to verify whether previous RACT determinations currently represent an appropriate RACT level of control for $PM_{2.5}$ purposes, while stopping short of requiring an exhaustive re-analysis for all RACT sources. The EPA believes that much of the resource concerns expressed in comments were based upon concerns that VOC sources are very numerous, and that this approach would require detailed review for these sources. As noted previously, a RACT analysis for VOC sources is required only if a State makes a finding that VOC sources significantly contribute to nonattainment in the State. We believe the commenters likely overestimate the resource implications of the certification process for prior RACT determinations. Another mitigating factor is that many of these same sources would be reviewed for purposes of implementing the eight-hour ozone standard. On the other hand, where a State or EPA determines that it is appropriate to regulate VOC sources for $PM_{2.5}$, EPA believes that it likely would be productive to review the previous determination for such sources, some of which have not been reviewed for many years.

Comment: One commenter believed that EPA should acknowledge detailed RACT and RACM analyses for the South Coast and San Joaquin Valley in California prepared during the 1990s for purposes of implementing the ozone and PM_{10} standards. The commenter believes that EPA acceptance of these determinations as RACT for $PM_{2.5}$ would enable States to focus resources on developing new measures needed for attainment.

Response: The EPA agrees that States should focus resources on new technologies and new developments. At the same time, EPA recognizes that for most source categories, new technology continues to be developed, and new information continues to be generated. Thus, even recent RACT determinations for a given source category may be outdated. Hence, the certification approach in the rule for the relevant sources or source categories is a reasonable approach which is designed to provide for the type of focused efforts suggested by the commenter.

Comment: One commenter believed that a State certification should only have to identify the existing RACT levels in a SIP and pollutants affected, but the State should not be required to provide any additional information.

Response: The EPA disagrees with this comment. The EPA believes that prior technology determinations should be taken into account in the RACT determination process. In reviewing existing RACT determinations, the State should provide supporting information to show that the existing technology in use should still be considered RACT, or it should show that there have been technology advances or cost reductions that have occurred since the previous

RACT limits were developed that make lower emissions technically and economically feasible in the context of RACT and would contribute to advancing the attainment date by at least one year.

Comment: Some commenters supported EPA's requirement for year-round operation of NO_X pollution control devices as RACT, given that $PM_{2.5}$ is an annual standard, while ozone is a summertime problem.

Response: The EPA agrees with these comments.

Comment: One commenter concluded that BACT and LAER determinations should be considered to satisfy RACT, regardless of the date they were made, because BACT and LAER by definition are more stringent than RACT.

Response: The EPA disagrees with this comment. The EPA believes that in many cases, but not all, BACT and LAER would assure RACT level of controls. Reasons that BACT and LAER might not satisfy RACT include: The pollutant of concern could have been different, the applicability threshold for BACT and LAER may have excluded smaller sources potentially subject to RACT controls, and technology advances or reductions in control costs may have occurred since the old determination was conducted.

Comment: One commenter recommended that EPA allow States to use information gathered from prior BACT or LAER analyses to complete the RACT determination, as was allowed in the 8-hour ozone NAAQS implementation rule.

Response: The final rule allows for use of such information, to the extent it remains valid, to inform a certification by the State that BACT or LAER technology continues to exceed what would currently be considered RACT.

Comment: Some commenters argued that any MACT determination that controls the pollutants of concern should be more than sufficient to satisfy RACT. Some commenters made similar recommendations regarding specific standards where PM limits were developed as a surrogate for HAPs, such as the MACT standard for integrated iron and steel mills, the MACT standard for iron and steel foundries, and the section 129 standards for waste to energy facilities.

Response: While agreeing that MACT controls are relevant, the EPA disagrees that all MACT determinations should be automatically considered to satisfy RACT. Reasons include: A MACT standard aimed at toxics might not ensure that the relevant $PM_{2.5}$ pollutant(s) are well controlled, MACT applicability provisions might have excluded units potentially subject to RACT, and technology advances or reductions in control costs might have occurred since EPA conducted the MACT analysis. The EPA believes that the State should review whether technology advances have occurred including available ''beyond the MACT floor'' technologies that may be reasonable in the context of RACT for $PM_{2.5}$ nonattainment, but which were not selected as MACT for purposes of implementing section 112. The EPA believes that RACT analyses should evaluate whether increased capture of $PM_{2.5}$ could be achieved, and whether an increased efficiency in controlling the fine fraction of particulate matter is reasonably available. The EPA has, however, added a specific recognition that MACT standards can reduce $PM_{2.5}$ as well as VOC, and that $PM_{2.5}$ information gathered for MACT standards development may inform a State's conclusions on available technologies for direct $PM_{2.5}$ emissions.

Comment: One commenter expressed a concern that EPA should not presume that MACT represents RACT where the MACT rule allows for a risk-based exemption from the control technology requirement.

Response: The EPA agrees with this comment.

11. How Should Condensable Emissions Be Treated in RACT Determinations?

a. Background

Certain commercial or industrial activities involving high temperature processes (fuel combustion, metal processing, cooking operations, etc.) emit gaseous pollutants into the ambient air which rapidly condense into particle form. The constituents of these condensed particles include, but are not limited to, organic material, sulfuric acid, and metals. In general, condensable emissions are taken into account wherever possible in emission factors used to develop national emission inventories, and States are required under the consolidated emissions reporting rule (CERR) [44] to report condensable emissions in each inventory revision. Currently, some States have regulations requiring sources to quantify condensable emissions and to implement control measures for them, and others do not. In 1990, EPA promulgated Method 202 in Appendix M of 40 CFR Part 51 to quantify condensable particulate matter emissions. In the proposed rule, EPA discussed and requested comment on issues related to condensable emissions in RACT determinations.

In the proposed rule, we noted that EPA is in the process of developing detailed guidance on a new test method which quantifies and can be used to characterize the constituents of the $PM_{2.5}$ emissions including both the filterable and condensable portion of the emissions stream. We also noted that when a source implements either of these test methods addressing condensable emissions, the State will likely need to revise the source's emissions limit to account for those emissions that were previously unregulated. For the purposes of determining RACT applicability and establishing RACT emission limits, EPA indicated in the proposal that it intends to require the State to adopt the new test method once EPA issues its detailed guidance. This guidance would be for use by all sources within a $PM_{2.5}$ nonattainment area that are required to reduce emissions as part of the area's attainment strategy.

b. Final Rule

Issues and comments related to test method and emissions limit issues for direct $PM_{2.5}$ for RACT, including discussion of test methods for condensable $PM_{2.5}$, are discussed in section II.L.3 of this preamble. The EPA recognizes that in some cases condensable emissions are more difficult to control than filterable emissions. However, condensable emissions may be assumed to be almost entirely in the 2.5 micrometer range and smaller, so these emissions are inherently more significant for $PM_{2.5}$ than for prior particulate matter standards addressing larger particles. Therefore, EPA encourages States to consider the potential for reducing condensable emissions when evaluating potential measures for RACT.

12. What Criteria Should Be Met To Ensure Effective Regulations To Implement RACT and RACM?

a. Final Rule

After the State has identified a RACT or RACM measure for a particular nonattainment area, it must then implement that measure through a legally enforceable mechanism (e.g., a State rule approved into the SIP). The legally enforceable mechanism must meet four important criteria.

First, the baseline emissions from the source or group of sources and the future year projected emissions must be quantifiable so that the projected emissions reductions from the sources can be attributed to the specific

[44] The consolidated emissions reporting rule was published in the **Federal Register** on June 10, 2002, pages 39602–39616.

measures being implemented. It is important that the emissions from the source category in question are accurately represented in the baseline inventory so that emissions reductions are properly calculated. In particular, it is especially important to ensure that both the filterable and condensable components of $PM_{2.5}$ are accurately represented in the baseline since traditional Federal and State test methods have not included the condensable component of particulate matter emissions and have not required particle sizing of the filterable component.

Second, the control measures must be enforceable. This means that they must specify clear, unambiguous, and measurable requirements. When feasible, the measurable requirements for larger emitting facilities should include periodic source testing to establish the capability of such facilities to achieve the required emission level. Additionally, to verify the continued performance of the control measure, specific monitoring programs appropriate for the type of control measure employed and the level of emissions must be included to verify the continued performance of the control measure. The control measures and monitoring program must also have been adopted according to proper legal procedures.

Third, the measures must be replicable. This means that where a rule contains procedures for interpreting, changing, or determining compliance with the rule, the procedures are sufficiently specific and nonsubjective so that two independent entities applying the procedures would obtain the same result.

Fourth, the control measures must be accountable. This means, for example, that source-specific emission limits must be permanent and must reflect the assumptions used in the SIP demonstration. It also means that the SIP must establish requirements to track emission changes at sources and provide for corrective action if emissions reductions are not achieved according to the plan.

b. Comments and Responses

There were no comments on this section. The language above is very similar to the language in the proposal.

G. Reasonable Further Progress (RFP)

1. Background

Clean Air Act Section 172(c)(2) requires that plans for nonattainment areas ''shall require reasonable further progress,'' which as defined in Section 171(1) ''means such annual incremental reductions in emissions of the relevant air pollutant as are required by this part or may reasonably be required by the Administrator for the purpose of ensuring attainment of the applicable national ambient air quality standard by the applicable date.'' This section describes the requirements the Administrator is establishing for states to achieve reasonable further progress.

In general terms, the goal of these RFP requirements is for areas to achieve generally linear progress toward attainment. The RFP requirements were included in the Clean Air Act to assure steady progress toward attaining air quality standards, as opposed to deferring implementation of all measures until the end date by which the standard is to be attained.

2. Requirements for Areas With Attainment Dates of 2010 or Earlier

a. Background

In 40 CFR 51.1009(b)(1) of the proposed rule, EPA proposed that a State which submits an implementation plan that demonstrates that an area will achieve attainment by 2010 (i.e., achieves attainment level emissions during 2009) would not be required to submit a separate reasonable further progress plan for that area. In such cases, EPA proposed that the attainment demonstration would also be considered to demonstrate that the area is achieving RFP.

b. Final Rule

In the final rule, EPA is maintaining the approach described in the proposed rule. An area that demonstrates attainment by 2010 will be considered to have satisfied the RFP requirement and need not submit any additional material to satisfy the RFP requirement. The EPA will view the attainment demonstration as also demonstrating that the area is making reasonable further progress toward attainment.

c. Comments and Responses

Comment: A number of commenters supported EPA's view that a demonstration of attainment by 2010 would also demonstrate that the area is making reasonable further progress toward attainment.

Response: The EPA appreciates the support and is adopting the supported approach.

Comment: A set of commenters objects to EPA's proposal, arguing that EPA cannot waive RFP requirements for areas where the state purports to demonstrate attainment. These commenters believe that Subpart 4 of Part D requires milestones prior to 2009, and these commenters believe that even Subpart 1 requires a demonstration of interim progress that EPA cannot waive.

Response: In brief, EPA is not waiving the RFP requirements for any area. Instead, EPA is concluding that a demonstration of attainment by 2010 also serves to demonstrate achievement of RFP. If the state submittal purports to demonstrate attainment but does not adequately make this demonstration, then the submittal also would not demonstrate achievement of RFP. The nature of the RFP requirement would then depend on whether the remedied attainment demonstration provides for attainment by 2010. Finally, as discussed above, EPA believes that Subpart 4 requirements do not apply to $PM_{2.5}$ plans. More detailed discussion of this comment and EPA's response are provided in the response to comments document.

3. Requirements for Areas With Attainment Dates Beyond 2010

a. Background

The proposed rule required a State to submit an RFP plan along with its attainment demonstration and SIP due in April 2008 for any area for which the State demonstrates that 2011 or later is the most expeditious attainment date. EPA proposed that the 2008 RFP plan must provide adequate emission reductions by 2009[45] and, in some cases, by 2012. The plan must demonstrate that emissions will decline in a manner that represents generally linear progress from the 2002 baseline year to the attainment year.

b. Final Rule

The final rule requires a State to submit an RFP plan along with its attainment demonstration and SIP due in April 2008 for any area for which the State justifies an extension of the attainment date beyond 2010. The RFP plan must provide emission reductions such that emissions in 2009 represent generally linear progress from the 2002 baseline year to the attainment year. Where the State justifies an extension of the attainment deadline to 2014 or 2015, the state must additionally provide emission reductions such that emissions in 2012 represent generally linear progress from the 2002 baseline year to the attainment year.

[45] The RFP test uses inventories for the full year, e.g. the year of 2009 or the year of 2012. EPA does not specifically require that the relevant measures be implemented by the beginning of the year, but RFP inventories must reflect the fact that measures that are implemented later in the year have correspondingly less impact on the year's annual total emissions.

If the State demonstrates that attainment will occur by 2010 or earlier, EPA will consider the attainment demonstration to demonstrate achievement of reasonable further progress, and the State will not be required to submit an additional RFP plan for the area.

c. Comments and Responses

Comment: For areas that demonstrate attainment by 2015 without adopting additional measures, a commenter recommended that the attainment demonstration be viewed as also demonstrating that the area is achieving RFP. The commenter therefore recommended that the state not be required to submit an RFP plan for such an area.

Response: A submittal that demonstrates attainment at the latest allowable date and does not address interim air quality fails to show that the path to attainment will yield interim incremental air quality improvements. States have ample opportunity to adopt measures that would provide interim air quality improvement long before 2015. Indeed, as discussed elsewhere as part of the discussion of attainment dates, a submittal that only addresses 2015 would also fail the attainment demonstration requirement, insofar as it would not be addressing whether attainment is as expeditious as practicable, because the submittal would fail to assess whether attainment could be achieved earlier. Therefore, irrespective of whether additional measures are needed to attain by 2015, the Clean Air Act mandates assessing progress at reasonable interim dates as well as mandating attainment.

4. Generally Linear Progress and Associated Timeline

a. Background

The EPA proposed that states with areas needing an extension of the attainment deadline beyond 2010 would be required to submit a plan demonstrating that emissions would be sufficiently reduced by 2009 to achieve a generally linear incremental improvement in air quality. The notice of proposed rulemaking provided an example calculation for an area with a 2013 attainment date, i.e. an area that achieves attainment level emissions in 2012. (See section III.G.4.b.iv of the proposal, 70 FR 66013.) In this example, the 2009 emissions year represents 7/10 of the period extending from the baseline year of 2002 to the 2012 year of attainment level emissions. Therefore, for this example, EPA's proposed requirement would be for this area to achieve emission reductions by 2009 representing approximately 7/10 of the emission reductions needed to attain the standards. For states with areas needing the attainment deadline extended to 2014 or 2015, EPA proposed to require achievement of generally linear emission reductions at two RFP milestone years—the 2009 and 2012 emission years.

The EPA received several comments on various elements of its proposed approach. Several commenters objected to EPA's proposed requirement to achieve linear progress toward attainment, asserting that EPA cannot reasonably expect states to achieve a significant amount of progress within a short time after plan submittals are due. Some commenters recommended requiring a specific emission reduction percentage, similar to the rate of progress requirement for ozone. These comments are addressed below.

b. Final Rule

The EPA is requiring States with areas needing an extension of the attainment deadline to submit RFP plans. These plans must demonstrate that generally linear reductions in emissions will occur by 2009, i.e. that emissions in 2009 will be reduced to the extent represented by a generally linear progression from 2002 base year emissions to attainment-level emissions. For any area that needs an extension of the attainment deadline to 2014 or 2015, the State's RFP plan would also need to demonstrate that generally linear reductions will be achieved in the 2012 emissions year as well.

c. Comments and Responses

Comment: Several commenters objected to EPA's proposed requirement that states demonstrate linear progress toward attainment. For example, a commenter stated that a ''generally linear reduction process may not be practicable.'' A commenter stated that it ''agrees that areas should be able to take credit for reductions from 2002 forward, [but] EPA should allow for fewer reductions (as opposed to linear reductions) prior to 2008.''

A commenter noted that EPA's ''proposed approach ignores several important realities about PM NAAQS implementation. First, * * * [n]ot until SIP submittal in April 2008, some 6 years after the RFP baseline date, will any local measures be finally adopted and approved. Under [the example EPA provided in its proposed rulemaking], states will be required to play 'catch-up' by achieving 70 percent of the required reductions in 2009. * * * Second, the 'generally linear' approach ignores that EPA intends for states to rely in large part on mobile source reductions and reductions in NO_X and SO_2 from CAIR implementation to achieve attainment in many areas. These measures fail a 'generally linear' test since most of the reductions they provide will not be realized until after 2009.'' This commenter continues that the incremental reductions in emissions required in the Clean Air Act need not be equal increments, that the absence of a specific statutorily mandated increment (such as the 3 percent per year requirement for ozone) allows EPA to be more flexible and to rely more heavily on later reductions. The commenter also argues that EPA's proposal is more stringent than the ozone RFP requirement, insofar as the ozone RFP requirement provides for averaging over 3 years. Similar comments were submitted by other commenters.

Another commenter supported EPA's proposal. This commenter supported requiring demonstrations that areas achieve emission reductions that will yield incremental improvement in air quality on a path toward expeditious attainment.

Response: The EPA believes that the requirement for generally linear reductions is reasonable because it allows States to take credit for early reductions achieved due to federal, State, and local programs. We find that it appropriately implements the RFP requirement in the Clean Air Act. For these reasons, EPA is finalizing the requirement that RFP plans for areas needing an attainment deadline extension show generally linear progress in reducing emissions from the base year through the 2009 emissions year. EPA is also requiring that areas needing an attainment deadline extension to 2014 or 2015 (i.e. attainment level emissions projected to start in 2013 or 2014) show generally linear progress in reducing emissions through the 2012 emissions year.

The commenters objecting to the requirement for generally linear progress appear to be assuming that only minimal emission reductions can be expected before 2008, so that a requirement for generally linear progress would require plans submitted in 2008 to compensate by achieving unrealistically high levels of emission reductions. The EPA disagrees with this assumption.

In fact, substantial emission reductions have occurred in the past few years and can be expected to occur through the 2009 emissions year. The EPA has promulgated significant mobile source rules recently that will yield

substantial benefits in the coming years, and these benefits follow a series of prior rules that provide a steady progression of emission reductions as newer, cleaner vehicles replace older, dirtier vehicles. For utilities, significant NO_X reductions occurred in 2004 under the NO_X SIP call, and substantial SO_2 reductions are expected to occur under the CAIR trading program prior to 2010 due to incentives for early reductions and the banking of allowances.

The EPA has also promulgated many other regulations that will reduce particulate matter and particulate matter precursor emissions before as well as after 2009. States have also been implementing a variety of measures. With use of a 2002 baseline, the assessment of RFP allows credit for these measures. The following is a partial list of the measures that have been adopted and will contribute to achieving generally linear reductions:

- NO_X SIP Call.
- Tightened emission limits for new gasoline and diesel vehicles.
- Numerous regulations requiring Maximum Achievable Control Technology, including regulations for:

—Iron and steel plants, including coke plants
—Industrial boilers
—Cement plants
—Lime plants
—Primary aluminum plants

- Numerous consent decrees for refineries.
- Numerous consent decrees for power plants.
- The Clean Air Interstate Rule for utilities.
- Retrofitted controls on diesel vehicles, and related programs for reducing diesel vehicle emissions.
- Closures of coke plants and other facilities (and, from a national perspective, replacement with cleaner new facilities).

While different control measures require various timelines for implementation, EPA believes that many of the additional measures that states might adopt for attainment planning purposes can be implemented in a timely fashion for addressing RFP requirements. Thus, EPA believes that states can reasonably be expected to assure that the combination of existing measures and additional measures as necessary will provide for generally linear progress in reducing emissions. Furthermore, particularly with respect to the 2009 RFP milestone year, when EPA evaluates whether the emission levels in a state plan represent generally linear progress, EPA will consider the availability of measures that can be implemented by 2009.

It is difficult to compare the stringency of this RFP requirement to the RFP requirement for ozone. The RFP requirement for ozone measures one form of progress that occurs after 3 years, and the requirement for $PM_{2.5}$ measures a different form of progress that occurs after 7 years (and for some areas also after 10 years). That is, the ozone RFP requirement applies a fixed, universally applicable emission reduction percentage for one pollutant (VOC), whereas EPA is defining the $PM_{2.5}$ RFP requirement as an area-specific combination of emission reductions for multiple pollutants, defined on the basis of each area's attainment demonstration.

The EPA believes that the Clean Air Act mandates not merely eventual attainment by 2015 but also that states demonstrate that emissions are being incrementally reduced in earlier years. (As discussed elsewhere, states must also demonstrate attainment by earlier than 2015 if feasible.) The requirement for RFP reflects Congressional intent that areas make steady progress toward attainment in the years before attainment occurs, and states have ample opportunity to assure that reductions occur well before 2015.

Comment: A commenter observes that the $PM_{2.5}$ nonattainment areas in its state also violate the ozone standard. The commenter observes, ''[i]n setting plan requirements, U.S. EPA should choose options that best facilitate harmonization of fine particulate and ozone control programs. This includes using a fixed percentage of emission reductions per year for reasonable further progress (RFP). We recommend the ozone RFP metric of three percent annual emission reductions averaged over three years.'' Another commenter also supports a more prescriptive RFP requirement, and comments that ''As suggested by EPA, nonattainment areas must be required to achieve 'a fixed percentage reduction of the emissions of direct $PM_{2.5}$ and regulated $PM_{2.5}$ precursors and in specific milestone years' between the base year and the attainment year proposed in the attainment demonstration.'' A third commenter supported establishing a requirement for a fixed emission reduction percentage, set at ''no less than the 3 percent rate'' in Section 182, with the possibility of higher rates in areas with more severe air quality problems.

Other commenters prefer the approach that EPA proposed. For example one commenter states that it agrees with EPA's approach of using the attainment demonstration to define the parameters for determining what constitutes RFP, and the commenter supports the flexibility of EPA's proposed approach ''rather than requiring fixed linear percentage reductions.'' Regarding the proposed option to require 3 percent per year emission reductions for areas classified as serious, some commenters recommended against establishing classifications and a fixed emission reduction percentage for any area.

Response: Requiring a fixed annual emission reduction percentage would impose a ''one-size-fits-all'' approach to address a range of circumstances. Requiring a fixed annual emission reduction percentage would overstate the reductions needed to achieve timely attainment in some areas and would understate the reductions needed to achieve timely attainment in other areas. The EPA believes that defining the RFP requirement in terms of achieving generally linear progress toward the emission reductions needed for timely attainment assures that each area will achieve a steady rate of progress most appropriate for the area to achieve timely attainment.

The EPA recognizes that many areas are nonattainment for both $PM_{2.5}$ and ozone and that the control programs for the two pollutants are sufficiently intertwined that harmonization of planning for meeting requirements applicable to the two pollutants is important. However, because the statutory requirements set forth in section 182 do not apply to $PM_{2.5}$ RFP plans, EPA believes it is neither necessary nor appropriate to impose these requirements for $PM_{2.5}$. Indeed, given the multiple pollutants that contribute to $PM_{2.5}$ and the variations that exist in the nature and composition of $PM_{2.5}$ across the country, EPA believes that the $PM_{2.5}$ RFP requirements for generally linear reductions are better defined to reflect these variations and thus better targeted toward the emission reductions that in each area can be expected to lead toward timely attainment. Further, EPA believes that application of a different form of the RFP requirement does not cause conflicts in implementation planning for the two standards. For example, reductions of NO_X emissions will generally reduce concentrations of both ozone and $PM_{2.5}$, and NO_X emission reductions are creditable for meeting both the ozone and the $PM_{2.5}$ RFP requirements.

An important distinction between $PM_{2.5}$ and ozone is that fine particle formation is in general a more complex process, affected by both direct emissions and numerous precursor pollutants. The EPA does not believe

that RFP targets for $PM_{2.5}$ should be the same as those used for the ozone implementation program, nor should the same percentage reduction be used for all $PM_{2.5}$ related pollutants. Instead, EPA believes that RFP plans should reflect an appropriate combination of pollutant reductions that most effectively provides for attainment. Therefore, EPA has defined an RFP requirement in which target emission reductions are established in conjunction with the area's attainment plan.

5. Geographic Coverage of Emissions Sources

a. Background

$PM_{2.5}$ concentrations reflect a combination of impacts over a wide range of geographic scales. For some components of $PM_{2.5}$, observed concentrations typically arise predominantly from sources within the nonattainment area. For other components, $PM_{2.5}$ concentrations may be influenced by sources across a broad area extending outside the nonattainment area. The EPA's intent is to define the RFP requirement in terms of emissions reductions that can be expected to provide generally linear improvements in air quality in the nonattainment area. For this purpose, EPA continues to believe that RFP requirements for $PM_{2.5}$ are best defined such that states evaluate emissions of each pollutant throughout the area in which the emissions substantially influence $PM_{2.5}$ concentrations in the nonattainment area.

As described in the proposed rulemaking, EPA expects each area's attainment demonstration to identify many of the parameters used to define the emission reductions that would represent RFP. First, the attainment plan will identify the pollutants that are being reduced to achieve attainment. Second, the attainment plan will identify the amount of reduction of each pollutant and the date by which attainment can be achieved. This information suffices to calculate a baseline set of reductions to be achieved by 2009 to provide for RFP. Third, where a state chooses to achieve RFP by reducing some pollutants earlier than others, the attainment plan will provide the information needed to assess whether the intended set of reductions can be expected to provide a comparable level of air quality improvement. Fourth, if the State intends to include emissions sources located outside the nonattainment area in its RFP plan, the information necessary to justify inclusion of such sources will likely be found in the attainment plan.

The EPA's proposed rulemaking identified several expectations regarding regional versus local impacts. For directly emitted $PM_{2.5}$ (including organic and other carbonaceous particles as well as miscellaneous inorganic particles and including condensable particulate matter), EPA recognized that impacts are commonly localized, and that direct emissions of $PM_{2.5}$ outside the nonattainment area should not be included in the RFP plan. Conversely, EPA recognized the regional nature of secondarily-formed sulfate and nitrate, and proposed that states could justify inclusion in the RFP plan of SO_2 and NO_X emissions sources located within 200 kilometers of the nonattainment area.

The EPA recognizes that fine particles travel over long distances, and that distant emissions of SO_2 and NO_X emissions can influence a nonattainment area's air quality. At the same time, distant sources can be expected to have less impact than sources closer to the nonattainment area. EPA's procedures for assessing RFP rely on a general assumption that all the sources included in the assessment have a comparable impact per ton of emissions. For this reason, it would be inappropriate to include distant emission sources in the assessment. Indeed, limiting the consideration of SO_2 and NO_X emissions to a 200 kilometer range is intended to assure that only sources with comparable impacts are included in the assessment.

b. Final Policy

The policy for addressing direct $PM_{2.5}$ emissions in RFP plans remains unchanged from the proposal: only emissions from within the nonattainment area may be included. Conversely, for SO_2 and NO_X, EPA believes that states could be able to justify considering not only all emissions in the nonattainment area but also emissions within a distance that may be up to 200 kilometers from the nonattainment area. States may also be able to justify consideration of VOC and ammonia emissions outside the nonattainment area on a case-by-case basis. As we explain more fully below in responding to comments, in situations where the state demonstrates that VOCs are a significant contributor to $PM_{2.5}$ concentrations in the area, it may be appropriate to include VOC emission sources within a distance of up to 100 kilometers of the nonattainment area. Given the uncertainties regarding ammonia emission inventories and the effects of reducing ammonia, EPA is not establishing a policy on this issue with respect to ammonia. States that expect to regulate ammonia should consult with their regional offices to determine appropriate approaches for those areas. The justification for considering emissions outside the nonattainment area shall include justification of the state's recommended definition of the area used in the RFP plan for each pollutant.

The EPA received comments objecting to the possibility that RFP inventories for areas outside the nonattainment area could include selected sources expecting substantial emission reductions while excluding other nearby sources expecting emission increases. Based on its review of these comments, EPA is revising its approach for considering regional emissions. If the state justifies consideration of precursor emissions for an area outside the nonattainment area, EPA will expect state RFP assessments to reflect emissions changes from all sources in this area. The State cannot include only selected sources providing emission reductions in the analysis. The inventories for 2002, 2009, 2012 (where applicable) and the attainment year would all reflect the same source domain (i.e. the same set of sources except for the addition of any known new sources or removal of known, creditably and permanently shut down sources).

In cases where the state justifies consideration of emissions of specified precursors from outside the nonattainment area, the state must provide separate information regarding on-road mobile source emissions within the nonattainment area for transportation conformity purposes. The EPA's transportation conformity regulations (40 CFR Part 93.102(b)) only require conformity determinations in nonattainment and maintenance areas, and these regulations rely on SIP on-road motor vehicle emission budgets that address the designated boundary of the nonattainment area. For this reason, if the state addresses emissions outside the nonattainment area for a pertinent precursor (i.e. a precursor for which mobile sources are significant, as discussed in the May 6, 2005 transportation conformity rule on $PM_{2.5}$ precursors at 72 FR 24280), the on-road mobile source component of the RFP inventory will not satisfy the requirements for establishing a SIP budget for transportation conformity purposes.

In such a case, the state must supplement the RFP inventory with an

inventory of onroad mobile source emissions to be used to establish a motor vehicle emissions budget for transportation conformity purposes. This inventory must address on-road motor vehicle emissions that occur within the designated nonattainment area, must be provided for the same milestone year or years as the RFP demonstration (i.e. 2009 and 2012 as applicable), and must satisfy other applicable requirements of the transportation conformity regulations. So long as the state provides this separate emissions budget EPA believes that this approach will optimally address both the RFP and the transportation conformity provisions of the Act.

The EPA is restricting the geographic area for RFP assessments to include only areas within the state or states represented in the nonattainment area. For a single state nonattainment area, only emissions within that state would be considered, even if other states may be within 200 kilometers of the nonattainment area. For multi-state nonattainment areas, only regions within states represented in the nonattainment area shall be included in the RFP assessment. This restriction is intended to address commenters' concerns about the enforceability of emission reductions included in the RFP assessment and helps assure accountability for these reductions. This topic is discussed further in the discussion below about multi-state nonattainment areas.

The EPA is retaining the approach that RFP assessments may not include direct $PM_{2.5}$ emissions from sources outside the nonattainment area. If a State regulates VOC or ammonia emissions as part of its attainment strategy, the RFP plan must include emissions of these pollutants. In the event that a State technical demonstration indicates that emissions of VOC or ammonia from sources outside the nonattainment area contribute significantly to $PM_{2.5}$ concentrations in the nonattainment area, EPA will consider on a case-by-case basis whether it would be appropriate to include emissions from such sources in the RFP plan.

c. Comments and Responses

The EPA received numerous comments on its proposal regarding how regional versus local impacts would be addressed. Multiple commenters objected to EPA's proposal that states could consider sources reducing emissions but ignore neighboring sources increasing emissions. Other commenters recommended that EPA support granting credit for reductions of direct $PM_{2.5}$ emissions that occur outside nonattainment areas. A few commenters also recommended different treatment of selected pollutants.

Comment: Several commenters object to the methods by which EPA proposed to account for reductions outside the nonattainment area. According to a set of commenters, if indeed sources outside the nonattainment area contribute to nonattainment, ''then EPA cannot lawfully or rationally allow the state to claim RFP credit from a single source's reductions without including in the baseline emissions from all sources (mobile, area and stationary) within the same distance from the nonattainment area, and without calculating the impacts of increases and decreases in such emissions on RFP. Viewing reductions from a single 'outside the area' source in isolation will invariably provide an incomplete and inaccurate picture of the actual increase or decrease in emissions contribution to the nonattainment area from all 'outside the area' sources. Moreover, EPA's proposal creates numerous opportunities to game and undermine the system. By allowing nonattainment areas to rely on RFP reductions made outside the nonattainment area, the proposed rule strays from the Act's focus on achieving emissions reductions from sources within the nonattainment area.'' Another commenter insisted that states should not be allowed to consider emissions from sources outside the area unless they can demonstrate the impacts of these sources on nonattainment area concentrations.

In addition, a commenter objects to consideration only of sources that are reducing emissions and recommends that EPA allow credit for upwind source reductions only ''on the condition that all other major sources in the 200 kilometer boundary are also not allowed to increase emissions.'' Another commenter supports an option which states would only consider emissions within the nonattainment area, observing that to consider emissions outside the nonattainment area would be difficult to administer and might inappropriately ''dilute the reductions needed in the nonattainment area.'' This commenter also observes that a 200 kilometer limit does not include much of the emissions that yield long range transport. Another commenter supports crediting reductions outside the nonattainment area but requests that EPA define the area to be considered.

Response: The EPA agrees that examining emissions reductions of only selected sources outside the nonattainment area gives an inaccurate assessment of the progress that an area is making. For example, if a state took credit for emission reductions at Source A but ignored equal emission increases at neighboring Source B, the state would claim emission reductions in its RFP plan when in fact no net emission reductions had occurred.

The commenters suggest various remedies for this problem. One suggestion is to include all sources within the area that is used. Another suggestion is to allow no consideration of emissions outside the nonattainment area. Yet another suggestion is to allow consideration of selected sources so long as other sources do not increase emissions.

The EPA is adopting the first of these suggestions: for the pertinent area outside the nonattainment area, the RFP assessment must include emissions (for all years evaluated) for all sources. The EPA believes that inclusion of all sources is needed to ensure that the RFP plan reflects the actual net emissions changes that are occurring in the relevant area.

In cases where the state justifies consideration of emissions of specified precursors from outside the nonattainment area, EPA is accepting the recommendation of various commenters that the inventories of these precursors used for RFP purposes shall include mobile source emissions as well as stationary and area source emissions. However, in cases where onroad mobile source emissions are significant and are therefore included, the state would need to submit additional information for transportation conformity purposes. As discussed above, in accordance with existing transportation conformity regulations (40 CFR Part 93), the SIP's motor vehicle emissions budget(s) must reflect an emissions inventory of on-road mobile source emissions for the nonattainment area. Consequently, in these cases, the state would need to supplement its RFP inventory with information identifying the inventory of on-road mobile source emissions within the nonattainment area for the pertinent precursor(s) for the applicable year or years (i.e. 2009 and potentially 2012) to be used to establish a motor vehicle emissions budget for transportation conformity purposes.

The relevant comments in general did not address the dimensions of spatial domain of the sources outside the nonattainment area that would be used in assessing RFP. EPA agrees with a commenter urging, as a prerequisite to including sources of the pertinent pollutants outside the nonattainment

area in the assessment, that states must justify the inclusion of sources outside the nonattainment area. This justification would need to demonstrate that these emissions have a substantial impact on nonattainment concentrations that warrants including these emissions along with nonattainment area emissions in assessing RFP. Another commenter recommends that EPA define the area to be included. Since the demonstrations of impact are best done by states, in conjunction with their attainment planning, EPA intends to allow States to justify the area to be included, within distance limits discussed above.

Comment: Numerous commenters recommend that EPA allow credit for reductions of direct $PM_{2.5}$ emissions outside the nonattainment area. Some of these commenters also recommend that EPA allow credit for mobile source emission reductions outside the nonattainment area. Other commenters support EPA's proposed approach, in which states may justify considering precursor emissions outside the nonattainment area but must evaluate direct $PM_{2.5}$ emissions based solely on emissions within the nonattainment area.

Response: Under Section 107 of the Clean Air Act, EPA is to designate nonattainment areas that include areas nearby to the violations that contribute to the violations. Given the spatial scale of the impacts of direct $PM_{2.5}$ emissions, EPA believes that any direct $PM_{2.5}$ emission source that demonstrably influences nonattainment area violations (and thus would contribute to these violations) would also be considered to be nearby to the violations for designation purposes. The EPA believes that it has properly defined the nonattainment areas to include all nearby contributing sources. Nevertheless, EPA asks anyone with evidence that an additional source or source area contributes to violations in a nonattainment area to submit that information to EPA and to recommend incorporation of that source or source area into the nonattainment area.

The EPA has commented on consideration of mobile source emissions above. For direct $PM_{2.5}$ emissions, EPA believes that the nonattainment area properly defines the area of consideration, and emissions from mobile sources outside the nonattainment area, like emissions from stationary sources outside the nonattainment area, should not be considered. For precursors for which consideration of emissions outside the nonattainment area is justified, the applicable inventories would include emissions from all sources including mobile sources as well as stationary sources.

Comment: A commenter states that ''RFP credits for VOC should be granted for reductions achieved within the nonattainment area as well as [within] geographical limits outside of the nonattainment area.'' This commenter supports consistency with the ozone policy, which allows credit for NO_X reductions within 200 kilometers and VOC reductions within 100 kilometers of the nonattainment area. Another commenter makes similar comments regarding VOC and comments that ''[a]s the science and understanding of $PM_{2.5}$ formation increases, EPA must revisit the 200 kilometer parameter and develop a possible proposal for ammonia.''

Response: Conceptually, EPA agrees that in areas where anthropogenic VOC emissions outside the nonattainment area are shown to be a significant contributor to nonattainment area $PM_{2.5}$ concentrations, presumably by formation of organic particles that influence nonattainment area concentrations, reduction of these VOC emissions could help improve air quality in the nonattainment area. Therefore, EPA is revising its policy to accommodate consideration of these potential impacts. The EPA believes that as the impacts of anthropogenic VOC on $PM_{2.5}$ concentrations are better understood, it may in some cases be appropriate to consider sources outside the nonattainment area in RFP plans if the impacts from such sources can be properly quantified and justified.

Nevertheless, EPA must highlight the technical challenges involved in assessing the impacts of VOC emission reductions. First, it is essential that the impacts of secondary organic particle formation from anthropogenic VOC emissions be differentiated from the impacts caused by biogenic VOC emissions and from the impacts of direct organic particle emissions. Second, the process of organic particle formation is highly complex, and currently available atmospheric models typically perform poorly in assessing the mass of particles thus formed. Third, the distance range of impacts, and to be more precise the distance range over which source impacts are comparable, is especially uncertain. While the distance range for organic particle formation is not necessarily the same as for the influence of VOC on ozone formation, it may be appropriate to include sources within 100 kilometers of the nonattainment area for both purposes, as the commenter recommended. However, any state wishing to include such sources outside the nonattainment area must justify the distance range that is appropriate for the area.

The EPA is not prepared at this time to establish generally applicable guidance with respect to how RFP plans should address ammonia in cases where that precursor is found to be significant. States that expect to regulate ammonia emissions should consult their regional office regarding appropriate approaches for their particular areas.

Finally, EPA agrees with the commenter that EPA should revisit the range of issues regarding geographic distances of impacts as more information and understanding become available.

6. Pollutants To Be Addressed in the RFP Plan

a. Background

A number of commenters appeared to be confused by the discussion in the notice of proposed rulemaking regarding the pollutants to be included in the RFP assessment. The EPA proposed that the attainment demonstration would provide the key parameters of the RFP demonstration, and that the list of pollutants to be addressed in the RFP demonstration would match the list of pollutants regulated as part of the attainment demonstration. However, the notice of proposed rulemaking also suggested that the presumptions regarding whether different pollutants are to be regulated under NSR and RACM (including RACT) would also apply to RFP. This led some commenters to recommend different treatment of specific pollutants.

In fact, the presumptions of applicability that EPA is promulgating for RACM are not germane to RFP. The pollutant coverage of RFP assessments is determined on an area-specific basis according to each area's attainment demonstration, and EPA need not establish presumptions as to what pollutants are included in the RFP assessment. For example, if a state includes no NO_X emission reductions in its attainment plan, then the RFP plan would not include NO_X, irrespective of whether the (uncontrolled) NO_X emissions contribute significantly to the areas $PM_{2.5}$ concentrations.

The contrast between establishment of presumptions for RACM and having no such presumptions for RFP (or for attainment demonstrations) reflects differences in regulatory context. For RACM, at issue is whether the impact of the pollutant is sufficient to warrant full implementation of the RACM requirements. In contrast, for RFP (as for attainment plans), EPA is establishing

an overall progress requirement that may be met by applying various control levels to various pollutants, so long as overall emission reductions are adequate. Indeed, if the state chooses not to control a particular pollutant in its attainment plan, then the presumption is that that pollutant would not be reduced in the RFP plan either. Furthermore, states have the flexibility to meet the overall progress with any adequate combination of control of relevant pollutants, regardless of the significance or insignificance of these pollutants' impacts. For these reasons, EPA is making no presumptions as to what pollutants will be included in RFP plans.

b. Final Policy

As proposed, the pollutants to be addressed in the RFP plan are those pollutants that are subject to control measures in the attainment plan.

c. Comments and Responses

Comment: A commenter states that ''VOC should be considered a presumptive $PM_{2.5}$ precursor.'' Another commenter recommends presuming that VOC and ammonia are included in the RFP plan.

Response: The EPA's approach to RFP does not rely on presumptions as to whether a pollutant does or does not warrant regulation as a precursor. Instead, pollutants are to be included or excluded according to whether the attainment demonstration includes emission controls for the pollutant that yield quantitative air quality benefits. Thus, irrespective of the presumptions applicable to RACM, the RFP plan would not include VOC unless the attainment plan reflects air quality improvements from VOC emission controls. The challenges of addressing VOC as part of an RFP plan were discussed earlier in this section. Similarly, ammonia would not be included in the RFP plan if the attainment plan does not regulate ammonia emissions.

7. Equivalent Air Quality Improvement

a. Background

The EPA proposed that states could use alternative combinations of various types of emission control programs to meet RFP requirements if the alternative would be expected provide air quality improvements that are approximately equivalent to those of the benchmark emission reductions. Some control programs for some pollutants can be implemented more quickly than other control programs. EPA believes that it is unnecessary to require that all pollutants be reduced at the same rate or by the same fraction of the ultimate attainment plan reductions. The EPA believes instead that the states should have flexibility to ''mix and match'' control strategies, so long as they provide a demonstration that the adopted approach can be expected to yield approximately the same air quality progress as an approach in which the state achieves an identical fraction of the attainment strategy for all pollutants by the RFP milestone date.

The notice of proposed rulemaking presented examples of the assessment of RFP, illustrating EPA's recommended approach for establishing a benchmark set of emission reductions and illustrating EPA's recommended procedures for whether modified approaches that control some pollutants earlier than other pollutants may be considered equivalent. While not repeated here, the examples remain appropriate for describing the approach included in the final rule. (See 70 FR 66012–66013).

Most commenters supported EPA's proposal to allow alternative combinations of control that can be shown by simple means to be equivalent. A set of commenters objected to this approach, given the uncertainties involved in the equivalency assessment. Nevertheless, for this aspect of RFP policy, EPA's final policy reflects the policy that it proposed.

b. Final Policy

The EPA is adopting an approach that establishes a benchmark level of controls but allows states the flexibility to adopt any combination of controls of the various pollutants that can be shown to provide equivalent benefits using procedures that EPA is recommending (or at the State's option, air quality modeling). The first step is to determine the ratio of the number of years from the baseline year to the RFP review year (e.g., the 7 years from 2002 to 2009) divided by the number of years from the baseline year to the year in which attainment level emissions are achieved (e.g. the 10 years from 2002 to 2012, for an area with a 2013 attainment deadline). The benchmark level of controls is then determined by multiplying this ratio times the level of control being achieved for each pollutant. For example, for an area with an attainment deadline extended to 2013, the benchmark level of controls would reflect 7/10 of the emission reductions of each pollutant that is controlled in the attainment plan.

The equivalency process involves consideration of the air quality benefits for the emission reductions in the alternative plan for each regulated pollutant. In effect, the air quality benefits for each pollutant are used as weighting factors, such that pollutants for which controls yield larger benefits are weighted more heavily in determining the adequacy of the resulting plan. For each pollutant, the first step is to find the ratio of the emission reductions achieved by the RFP milestone date (e.g. the emission reductions achieved between 2002 and 2009) divided by the emission reductions achieved by the attainment date. The second step is to multiply this ratio times the air quality improvement attributable to full implementation in the attainment year of the attainment strategy relevant to that pollutant. The third step is to add these pollutant-specific results to obtain a total estimated air quality benefit of the alternative plan.

The air quality benefits of the benchmark reductions are easier to determine. The first step, inherent to defining the benchmark reductions, is to determine the ratio of the number of years to the RFP review divided by the number of years to attainment level emissions (in the example above, 7/10). The second step is simply to multiply this ratio times the quantity of air quality improvement achieved by the attainment plan. (Conceptually, the calculations are the same as are done for the alternative plan, but the mathematics are simpler because one is applying the same assumed fraction of the attainment plan emission reductions (e.g. 7/10) for all pollutants, so that there is no need to subdivide by pollutant.) For each milestone date, any alternative that provides estimated air quality benefits by the RFP milestone date that at a minimum are generally equivalent to the estimated benefits of the benchmark level of emission reductions will be considered to satisfy RFP requirements.

c. Comments and Responses

Comment: A set of commenters argues that the equivalency process is too uncertain, and recommends instead that states be required to achieve at least a fixed percentage reduction for all pollutants. The commenters cite the uncertainties acknowledged by EPA, including potential nonlinearity (i.e. that a given percentage of an emission reduction may yield a different percentage of the related air quality benefit). The commenters contrast EPA's willingness to accommodate these uncertainties, for purposes of giving states flexibility for alternate RFP plan designs, with EPA's unwillingness to accommodate the uncertainties inherent

in regulating ammonia emissions. The commenters state that ''Rather than propose a standardized process for coherently determining 'equivalency,' EPA embraces the possibility that States will invent multiple and disparate methodologies.'' The commenters argue that the need for certainty in achieving emission reductions trumps the benefits of state flexibility, not the other way around. The commenters state that if ''EPA decides nonetheless to accept equivalency demonstrations, it should at least * * * require States to conduct dispersion modeling'' to confirm equivalency. The commenters further find unlawful the fact that EPA would allow ''rough equivalency'' rather than full equivalency to the benchmark approach. The commenters would prefer that EPA required a fixed percentage reduction of the emissions of direct $PM_{2.5}$ emissions and of each precursor.

Response: The EPA believes that its proposed approach satisfies the intent of the RFP requirement, which is to make ongoing, steady progress toward attainment rather than backloading control strategies. A requirement to obtain at least a given percentage of each of the pollutants that contribute to $PM_{2.5}$ concentrations would impose an inflexibility that EPA concludes is unnecessary where not required by the statute. The EPA proposed to require that areas achieve emission reductions that are generally linear, and a plan that provides for rough equivalency to the benchmark approach would indeed provide generally linear reductions. In response to commenters' requests for a standardized process for assessing equivalency, EPA believes the process outlined in the final rule is responsive to this request. It is not clear whether the fixed reduction percentage that certain commenters recommended would be an area-specific percentage (such as EPA uses to define the benchmark approach) or a universally applicable percentage (such as 3 percent per year). If the former, then EPA would repeat the response above regarding flexibility being consistent with the Act's requirements; if the latter, then responses in III.6.4 regarding a fixed reduction percentage apply. The EPA believes that the procedures it is establishing to assess equivalency are adequate for assessing RFP and that dispersion modeling need not be required for this purpose.

8. Other RFP Issues

a. Multi-State Nonattainment Areas

As stated in the proposed rulemaking, EPA seeks to ensure that nonattainment areas that include more than one State meet RFP requirements as a whole. Some commenters expressed concern about how one state's submittal should address emissions in other states, including how the state might address questions about the enforceability of another state's requirements.

The issues here resemble the issues for attainment demonstrations. In that context as well, EPA seeks plans that reflect active consultation by the affected states and provide a combination of reductions that are enforceable by the respective states that collectively provide for attainment. The active involvement of regional planning organizations helps assure a collective design of a plan with specific requirements to be adopted by specific states. Likewise for RFP, EPA would expect states with multi-state nonattainment areas to consult with other involved states, to formulate a list of the measures that they will adopt and the measures that the other state(s) will adopt, and then to adopt their list of measures under the assumption that the other state(s) will adopt their listed measures. That is, each state would be responsible for adopting and thereby providing for enforcement of its list of measures, and then that state and ultimately EPA (at such time as the plan is approved) would be responsible for assuring compliance with the SIP requirements.

In accordance with this view of RFP, as is the case for attainment plans, EPA expects states sharing a multi-state nonattainment area to submit a common assessment of whether RFP will occur. As a default, if the assessment only includes emissions within the nonattainment area, then each state would submit an assessment based on emissions from the full nonattainment area including portions of the area in other states. If the assessment includes precursor emissions from additional area outside the nonattainment area, then the states should have a common rationale for the area included, and all affected states would use the same inventory of the same multi-state area thus defined in assessing whether RFP will occur. The EPA would judge such submittals based on (1) whether the overall projected emission reductions will achieve RFP and (2) whether the submitting state has adopted the necessary enforceable measures to assure that the reductions projected within its boundaries will in fact occur.

As a point of clarification, even if a state justifies consideration of emissions outside the nonattainment area in its RFP assessment, EPA intends that these assessments not use emissions from outside the state or states represented in the nonattainment area. For single state nonattainment areas, only emissions within that state would be considered. This will help assure accountability for the emission reductions included in the plan.

b. Tribal Areas

The EPA received no comments on its proposed policy regarding RFP for tribal areas, and EPA is finalizing the proposed policy. Under its Tribal Authority Rule (40 CFR 49.4), EPA found that it was not appropriate to apply SIP schedule requirements to tribes. For similar reasons, EPA is not requiring tribes to submit RFP plans. Generally this exemption will have limited if any impact on the achievement of RFP by an area. Nevertheless, consistent with its general role in implementing programs for tribes where ''necessary and appropriate,'' EPA will work with the affected tribes and states to ensure that emissions on tribal lands are addressed appropriately. The EPA intends to ensure that areas that include both state and tribal lands will satisfy RFP on a collective basis, similar to the policy applicable to multi-state nonattainment areas.

9. Mid-Course Review

a. Background

The EPA proposed requiring mid-course reviews on a case-by-case basis. The proposal described a mid-course review as a combination of reviews aimed at assessing whether a nonattainment area is or is not making sufficient progress toward attainment of the $PM_{2.5}$ standards. The proposal described the mid-course review as involving ''three basic steps: (1) Demonstrate whether the appropriate emission limits and emission reduction programs that were approved as part of the original attainment demonstration and SIP submittal were adopted and implemented; (2) analyze available air quality, meteorology, emissions and modeling data and document relevant findings; and (3) document conclusions regarding whether progress toward attainment is being made using a weight of evidence determination.'' (Cf. 70 FR 66010)

The EPA views mid-course review requirements as part of a set of requirements for implementing the Clean Air Act requirements for reasonable further progress. For areas that demonstrate attainment by April 5, 2010, EPA believes that this attainment demonstration also demonstrates that reasonable further progress is being achieved. For areas that demonstrate

attainment after April 5, 2010, EPA is requiring states to submit an RFP plan, due on April 5, 2008, showing that emissions in 2009 and, in some cases, in 2012, will be sufficiently reduced to provide generally linear progress toward levels that are expected to yield attainment. At issue here is how then to conduct ongoing tracking of whether the planned progress toward attainment is in fact occurring. Subparts 2 (for ozone) and 4 (for PM_{10}) include explicit requirements for ongoing milestone tracking. Since Subpart 1 (applicable for $PM_{2.5}$) allows EPA flexibility in determining how ongoing progress is to be tracked, EPA may adopt other approaches for achieving the necessary assurances that ongoing progress toward attainment is occurring.

Milestone reviews can be confounded by changes in inventory methods (a concern expressed by a commenter particularly with respect to condensable emissions) and involve lengthy delays while inventories are compiled before planning can begin. Other approaches involving only air quality data reviews also do not provide for timely planning, insofar as such approaches involve waiting for three years of air quality data after implementation of controls before planning can begin. The EPA believes that a mid-course review provides the most productive approach, in lieu of establishing milestone tracking or other requirements, to assure that reasonable further progress in reducing emissions is being achieved. For this reason EPA proposed a requirement for mid-course reviews.

The EPA proposed a process for establishing and implementing mid-course review. After the state submits an attainment plan (due in April 2008), EPA would evaluate whether a mid-course review is warranted after considering various factors including factors identified in the proposal. The EPA did not propose to conduct further rulemaking on establishing this requirement, but EPA proposed that ''[w]here EPA finds that a MCR would be required, the approval of the [attainment] demonstration would be contingent on a commitment from the State to conduct the MCR.'' The mid-course review would then be due April 2010. The EPA's proposal also stated that ''EPA would determine [based on review of the mid-course review] whether additional emissions reductions are necessary,'' so that states would need to complete the mid-course review ''three or more years before the applicable attainment date to ensure that any additional controls that may be needed can be adopted [in timely fashion].'' Finally, EPA stated ''[i]f a mid-course review will be required for certain $PM_{2.5}$ nonattainment areas, separate $PM_{2.5}$ mid-course review guidance will be written to address the specific requirements of $PM_{2.5}$ nonattainment areas.''

The EPA received numerous comments objecting to EPA's proposed approach. Several commenters noted the inconsistency between requiring a mid-course review in April 2010 versus requiring a mid-course review due 3 or more years before an attainment date of 2012 or earlier. Multiple commenters objected to EPA requiring a mid-course review only 2 years after the initial attainment plan is due. A commenter requested ''nationally applicable guidance on when an MCR would be required and what it would need to include.'' No commenters supported EPA's timeline for mid-course reviews.

Based on the comments that EPA received, EPA has reevaluated the process for mid-course reviews. Upon reevaluation, EPA shares many of the concerns expressed by commenters about the proposal. The proposal indeed presents conflicting dates for submittal. The EPA agrees that a deadline just 2 years after the initial SIP submittal is too soon for states to conduct meaningful analyses of whether areas are making progress towards attainment. This problem would be exacerbated by the proposed process, in particular the fact that states would not know to begin work on a mid-course review until after they had submitted their initial SIP and after EPA had sufficiently reviewed the submittal to determine the need for a mid-course review. An early mid-course review also would defeat one of the purposes of the mid-course review, which is to take advantage of advances in the science and understanding of the nature of condensables and other components of $PM_{2.5}$, to adjust plans to be better targeted at solving problems. For these reasons, EPA is significantly revising its approach to mid-course reviews as recommended by the commenters. The EPA is establishing a rule which provides more certainty to the states as to applicability and content of mid-course review requirements, thereby avoiding the need for future EPA rulemakings on the subject. The EPA's rule clearly does not require states with early attainment dates to conduct a mid-course review and would clearly mandate a mid-course review only for areas with later attainment dates. The EPA's final rule clarifies the content of mid-course reviews and provides for states to make decisions on whether further controls are needed rather than having EPA make this determination. The mid-course review shall include an updated modeled attainment demonstration as well as a review of the implementation of measures in the April 2008 SIP and a review of recent air quality data. The EPA believes that all of these elements are necessary and should be sufficient for the state to identify whether additional measures are needed to achieve attainment by the attainment date in the approved plan. The EPA believes that states, not EPA, should make the initial determination as to whether additional measures are needed, and EPA has designed its mid-course review requirements to provide for the states to make this determination.

The EPA is promulgating a fixed date of April 2011 as a date for submittal of mid-course reviews for areas with attainment dates in 2014 or 2015. This fixed date will facilitate joint planning for multiple areas to apply common assumptions regarding regional transport. This date also gives states adequate notice for preparing these reviews and adequate time after the April 2008 submittal to incorporate new information and understanding of $PM_{2.5}$ nonattainment problems to adjust attainment strategies as appropriate.

The EPA is not requiring areas demonstrating attainment by 2013 or before to conduct a mid-course review. Such areas plan to have attainment level emissions by 2012, and EPA believes that an April 2011 mid-course review would not provide a timely reassessment of such areas' attainment plans. Instead, EPA is clarifying that mid-course reviews are only required for areas that demonstrate a need for an attainment date extension at least to April 2014.

b. Final Rule

For each area with an approved attainment date in 2014 or 2015, EPA is requiring the state to submit a mid-course review by April 2011. The mid-course review shall include an updated attainment demonstration as well as a review of the implementation status of measures included in the April 2008 submittal and a review of recent air quality data. The state shall determine whether additional measures are needed for timely attainment, just as the state is responsible for determining whether additional measures are needed in the April 2008 attainment demonstration, subject to formal EPA SIP review. The EPA is not requiring RFP milestone reviews, and EPA is requiring mid-course reviews for areas with sufficiently extended attainment dates in lieu of any other form of tracking reasonable progress.

c. Comments and Responses

Comment: A number of commenters objected to EPA's proposed timeframe that would have areas submit a mid-course review only 2 years after the initial SIP is due. They recommended, instead, that areas with attainment dates 2 years or more beyond the first 5-year period submit mid-course reviews 3 years after the SIPs are due (April 2011) and every 3 years thereafter, if necessary. Their reason for this suggestion is that the timing of mid-course review requirements needs to be clearer and should allow adequate time between plans and mid-course reviews if they are to serve as meaningful reviews.

Several commenters also noted an inconsistency in the timing of mid-course review requirements under EPA's proposal. The EPA proposed that mid-course review submittals would be due 5 years after the initial designation, which for all the original designations means 5 years after April 2005, i.e. April 2010. However, EPA also proposed that mid-course reviews would be due 3 years before the attainment date, which for areas with an April 2012 attainment date means April 2009. The commenters considered April 2009 for a mid-course review submittal to be too soon after the initial SIP submittal in April 2008, arguing that EPA would not have had time to review the 2008 SIP submittal, and the states would not have time to prepare a mid-course review by 2009. Some of these commenters expressed a view that EPA should not require mid-course reviews earlier than 3 years after the SIP submittal date.

Response: The EPA agrees with these comments. The EPA is remedying the inconsistency in submittal dates by establishing the single submittal due date of April 2011 that was recommended by the commenters. As requested by commenters, EPA is also clarifying the applicability of the mid-course review requirement. The requirement shall apply to areas with attainment dates of 2014 or 2015; mid-course reviews shall not be required for areas that are expected to attain the standards by 2013.

Comment: A commenter supports mid-course reviews as a means of assuring that areas with longer-term compliance dates are on track to attain the NAAQS as expeditiously as practicable.

Response: The EPA agrees that mid-course reviews can be a critical step in assuring expeditious attainment for areas with extended attainment dates. Indeed, EPA is relying on mid-course reviews rather than milestone reviews or other forms of RFP tracking to serve this purpose.

Comment: A commenter recommended eliminating mid-course review requirements for any area with less than seven years between SIP submittal and attainment. The commenter urged that EPA carefully reconsider its overall timelines for $PM_{2.5}$ while considering the feasibility and practical usefulness of the steps required of States and emission sources.

Response: The EPA agrees that the proposed timeline potentially required mid-course reviews in areas where such reviews would not be warranted, and the timeline did not provide the clarity as to the applicability of the requirement that states need to fulfill their planning responsibilities. In response, EPA is not requiring mid-course reviews for areas demonstrating attainment prior to 2014. For those areas that cannot demonstrate that attainment will occur prior to 2014, EPA has streamlined the mid-course review process so that the state bears responsibility for making the initial determination as to whether additional measures are needed to achieve timely attainment, rather than requiring additional steps of EPA rulemaking and initial findings by EPA as to the level of controls needed in the state's SIP. With the revised timetable, states can be assured of a meaningful mid-course review effort that focuses on the areas that particularly warrant such a review and for which time is available for a productive assessment of the need for additional measures.

Comment: One commenter stated that the proposal that allows the Agency to determine whether or not a State needs to submit a mid-course review with their attainment demonstration on a case-by-case basis lacks sufficient information. Since these attainment demonstrations must meet rigorous criteria, and require substantial work by the States, the commenter is concerned that the proposal neglects to outline the criteria EPA will use to make the case-by-case mid-course review determinations. The commenter asks that EPA provide the States with nationally applicable guidance on when an MCR would be required and what it would need to include.

Response: The EPA agrees with this comment. In particular, EPA agrees that establishing clear criteria for applicability and content of a mid-course review requirement will provide states the opportunity to plan for these reviews and conduct appropriate reviews in a timely fashion. Therefore, this final rule is establishing specific criteria for the applicability of the mid-course review requirement, namely that a mid-course review shall be conducted for any area that cannot demonstrate attainment before 2014. This final rule is also identifying the necessary elements of this mid-course review, i.e. a review of the implementation of measures in the 2008 SIP, and review of recent air quality data, and an updated modeled attainment demonstration.

H. Contingency Measures

a. Background

Under subpart 1 of the CAA, all $PM_{2.5}$ nonattainment areas must include in their SIPs contingency measures consistent with section 172(c)(9). Contingency measures are additional control measures to be implemented in the event that an area fails to meet RFP or fails to attain the standards by its attainment date. These contingency measures must be fully adopted rules or control measures that are ready to be implemented quickly upon failure to meet RFP or failure of the area to meet the standard by its attainment date. The preamble to the proposal stated that the SIP should contain trigger mechanisms for the contingency measures, specify a schedule for implementation, and indicate that the measures will be implemented without significant further action by the State or by EPA. The contingency measures should consist of other control measures for the area that are not included in the control strategy for the SIP.

The April 16, 1992 General Preamble provided the following guidance: ''States must show that their contingency measures can be implemented without further action on their part and with no additional rulemaking actions such as public hearings or legislative review. In general, EPA will expect all actions needed to affect full implementation of the measures to occur within 60 days after EPA notifies the State of its failure.'' (57 FR at 13512.) This could include Federal measures and local measures already scheduled for implementation, as explained below.

The EPA has approved numerous SIPs under this interpretation—i.e., that use as contingency measures one or more Federal or local measures that are in place and provide reductions that are in excess of the reductions required by the attainment demonstration or RFP plan. (62 FR 15844, April 3, 1997; 62 FR 66279, December 18, 1997; 66 FR 30811, June 8, 2001; 66 FR 586 and 66 FR 634, January 3, 2001.) The key is that the statute requires that contingency measures provide for additional emission reductions that are not relied

on for RFP or attainment and that are not included in the demonstration. The purpose is to provide a cushion while the plan is being revised to meet the missed milestone. In other words, contingency measures are intended to achieve reductions over and beyond those relied on in the attainment and RFP demonstrations. Nothing in the statute precludes a State from implementing such measures before they are triggered. In fact, a recent court ruling upheld contingency measures that were previously required and implemented where they were in excess of the attainment demonstration and RFP SIP. *See LEAN* v. *EPA*, 382 F.3d 575, 5th Circuit., 2004.

One basis EPA recommends for determining the level of reductions associated with contingency measures is the amount of actual $PM_{2.5}$ emissions reductions required by the control strategy for the SIP to attain the standards. The contingency measures are to be implemented in the event that the area does not meet RFP, or attain the standards by the attainment date, and should represent a portion of the actual emissions reductions necessary to bring about attainment in area. Therefore, the emissions reductions anticipated by the contingency measures should be equal to approximately 1 year's worth of emissions reductions necessary to achieve RFP for the area.

As stated previously, EPA believes that contingency measures should consist of other available control measures beyond those required to attain the standards, and may go beyond those measures considered to be RACM for the area. It is important, however, that States make decisions concerning contingency measures in conjunction with their determination of RACM for the area, and that all available measures needed in order to demonstrate attainment of the standards must be considered first; all remaining measures should then be considered as candidates for contingency measures. It is important not to allow contingency measures to counteract the development of an adequate control strategy demonstration.

The preamble to the proposal stated that contingency measures must be implemented without ''significant further action'' after EPA determines that the area has either failed to meet RFP, or has failed to attain the standard by its attainment date. The purpose of the contingency measure provision is to ensure that corrective measures are put in place automatically at the time that EPA makes its determination that an area has either failed to meet RFP or failed to meet the standard by its attainment date. The EPA is required to determine within 90 days after receiving a State's RFP demonstration, and within 6 months after the attainment date for an area, whether these requirements have been met. The consequences for states which fail to attain or to meet RFP are described in section 179 of the CAA.

2. Final Rule

The final rule includes regulatory text for contingency measures and maintains the overall policy approach as described in the preamble to the proposal. The key requirements associated with contingency measures are:

—Contingency measures must be fully adopted rules or control measures that are ready to be implemented quickly upon failure to meet RFP or failure of the area to meet the standard by its attainment date.

—The SIP should contain trigger mechanisms for the contingency measures, specify a schedule for implementation, and indicate that the measures will be implemented without further action by the State or by EPA.

—The contingency measures should consist of other control measures for the area that are not included in the control strategy for the SIP.

—The measures should provide for emission reductions equivalent to about 1 year of reductions needed for RFP, based on the overall level of reductions needed to demonstrate attainment divided by the number of years from the 2002 base year to the attainment year. Contingency measures are those measures that would not be included in the attainment strategy for various reasons; for example, they may not be as economically feasible as other measures that are considered to be RACM, or it may not be possible to implement the measures soon enough to advance the attainment date (e.g. federal mobile source measures based on the incremental turnover of the motor vehicle fleet each year).

3. Comments and Responses

Comment: Several comments were received concerning the requirement for contingency measures under section 172(c)(9). The proposal indicated that contingency measures adopted as part of the State plan are to be equal to approximately 1 year's worth of emissions reductions necessary to achieve RFP, as determined by the attainment demonstration for the area. One commenter indicates that this amount of reductions for contingency measures may be excessive in some cases. The commenter stated that States should be allowed to demonstrate appropriate amount of reductions for contingency measures in each area based on the degree of the $PM_{2.5}$ nonattainment area problem and the progression of emission reductions planned for the area as a part of the SIP.

Response: The EPA agrees that the CAA does not include the specific level of emission reductions that must be adopted to meet the contingency measures requirement under section 172(c)(9). One possible interpretation of the CAA would assume that contingency measures should be in place in the event that all of the State's measures fail to produce their expected emission reductions. Under this scenario, the State theoretically would be required to adopt sufficient contingency measures to make up for the entire short fall. In other words, the State would have to adopt ''double'' the measures required to satisfy the applicable emissions reduction requirements.

The EPA believes that this scenario would be highly unlikely and that this interpretation would be an unreasonable requirement. The adoption of double the measures needed for attainment would be difficult for States. Therefore, the EPA believes that it is reasonable that contingency measures should, at a minimum, ensure that an appropriate level of emissions reduction progress continues to be made if attainment or RFP is not achieved, or if an area fails to attain the standard by its statutory attainment date and additional planning is needed by the State. The EPA believes that the contingency measures adopted by the State for the affected area should represent a portion of the actual emissions reductions necessary to bring about attainment in the area. Therefore, EPA believes that it is reasonable to require states to adopt contingency measures equal to approximately 1 year's worth of emissions reductions necessary to achieve RFP for the area.

Comment: One commenter claimed that EPA incorrectly quoted the CAA as requiring SIPs to provide for implementation of contingency measures upon an attainment or RFP failure, without ''significant'' further action by the State or EPA. The commenter stated that section 172(c)(9) does not contain the word ''significant.'' The CAA requires that contingency measures take effect ''without further action'' by the State or EPA.

Response: The EPA agrees with the commenter that the general requirements for attainment plans specified under section 172(c)(9) State that each plan must contain additional measures that will take effect without

'further action' by the State or EPA if an area either fails to make RFP or fails to attain the standard by the applicable attainment date. Section 51.1012 of the final rule describes the contingency measures requirement and does not include the word ''significant.'' However, as a matter of practicality states need to take minimal steps to make contingency measures effective and alert the affected public that the measures are in force. Thus, EPA has indicated based on conclusions first made in the 1992 General Preamble that states should complete all of these administrative steps within 60 days and that all regulatory steps be completed before SIP submission.

Comment: The commenter further states that EPA is wrong in asserting that contingency measures can include Federal measures and local measures already scheduled for implementation, or previously implemented measures that provide 'excess' reductions. The CAA requires contingency measures to consist of controls 'to be undertaken if' the area fails to meet attainment or RFP. The commenter states that this language clearly states that such measures are to be new measures that will be undertaken upon the triggering event specifically to address RFP or failure to attain, not measures already in place, or measures required for other reasons.

Further, the commenter claims that EPA can not rationally refer to any reductions prior to an attainment or RFP failure as 'excess' when total reductions in the area in fact prove insufficient to meet attainment RFP. The commenter states that EPA cites a 5th Circuit case as support, but the commenter respectfully submits that the case was incorrectly decided on this issue for the aforementioned reasons.

Response: In response to comments claiming that EPA is wrong in asserting that contingency measures can include Federal measures and local measures already scheduled for implementation, or previously implemented measures that provide 'excess' reductions, as stated previously, the EPA has approved numerous SIPs under this interpretation. The statute requires that contingency measures provide for additional emission reductions that are not relied on for RFP or attainment and that are included in the attainment demonstration for the area. These measures are intended to provide a ''cushion'' in terms of emissions reductions for the area while the State is revising the SIP for the area due to the failure to show RFP or attain. In other words, contingency measures are intended to achieve reductions over and beyond those relied on in the attainment and RFP demonstrations. Nothing in the statute precludes a State from implementing such measures before they are triggered.

As noted above, EPA's General Preamble interpreted the control measure requirements of sections 172(c)(9) and 182(c)(9) to allow nonattainment areas to implement their contingency measures early. 57 FR 13498, 13511 (April 16, 1992). The EPA has applied this interpretation in rulemakings. See, for example, 67 FR 6,590, 6,591–92 (September 26, 2002). See also rulemakings cited in the Background section, above. As set forth above, the Fifth Circuit has upheld EPA's interpretation. *Louisiana Environmental Action Network* v. *EPA,* 382 F.3d 575 (Fifth Cir. 2004). (''*LEAN*'') Commenters have not provided a basis for concluding that the Fifth Circuit in the *LEAN* case wrongly interpreted the CAA.

Commenters contend that the language in the CAA regarding contingency measure controls ''to be undertaken'' requires measures not already in place or required for other reasons. The Fifth Circuit disagreed, finding that the terms in section 172(c)(9)—''to be undertaken'' and ''to take effect''—were ambiguous, and finding persuasive EPA's interpretation that this language allows measures already in place or otherwise required. The Court held:

> ''Here, the EPA's allowance of early reductions to be used as contingency measures comports with a primary purpose of the CAA—the aim of ensuring that nonattainment areas reach NAAQS compliance in an efficient manner—and necessary requirements of the CAA.'' 382 F.3d at 583.

The Court further found that ''By utilizing contingency measures early, the contingency measures ensured that 'an appropriate level of emissions reduction progress' would be implemented while the State 'adopt[ed] newly required measures resulting from the bump-up to a higher classification.'' [citing the General Preamble]. *Id.*

In addition, the Court agreed with EPA that ''early reductions are necessary in order to create an incentive for nonattainment areas to implement 'all reasonably available control measures as expeditiously as practicable' '' in accordance with section 172(c)(1) of the CAA. Thus the Court concluded that it would be ''illogical to penalize nonattainment areas that are taking extra steps, such as implementing contingency measures prior to a deadline, to comport with the CAA's mandate that such states achieve NAAQS compliance as 'expeditiously as practicable.' '' *Id.* at 583–584.

The Fifth Circuit also endorsed the concept of ''excess'' reductions, noting that the reductions credits at issue in that case, ''although already implemented, are in effect set aside, 'to be applied in the event that attainment is [not] achieved' and such reduction credits 'are not available for any other use.' [citations omitted]. The setting aside of a continuing, surplus emissions reduction fits neatly within the CAA's requirement that a necessary element of a contingency measure is that it must 'take effect without further action by the State or [EPA]'.'' The Court concluded that ''the early activation of continuing contingency measures is consistent with the purpose and requirements of the CAA statute.'' Id. at 584.

Thus, EPA's approval of early implemented contingency measures is consistent with the CAA, as well as with EPA guidance. For example, EPA has consistently taken the position that ozone nonattainment areas classified moderate and above must include sufficient contingency measures so that ''upon implementation of such measures, additional emissions reductions of up to 3 percent of the emissions in the adjusted base year inventory (or such lesser percentage that will cure the identified failure) would be achieved in the year following the year in which the failure has been identified.'' 57 FR at 13511 (EPA's General Preamble). Thus the contingency measures are supposed to ensure that progress towards attainment will occur while the relevant State adopts whatever additional controls may be necessary to correct a shortfall in emissions reductions. *Id.* The EPA has historically allowed early reductions—that is, reductions achieved before the contingency measure is ''triggered''—to be used as contingency measures. See also August 13, 1993 Memorandum from G.T. Helms: Early Implementation of Contingency Measures for Ozone and Carbon Monoxide (CO) Nonattainment Areas).

The commenter's argument that emission reductions cannot be valid contingency measures if they are otherwise required is also misplaced. A State must have the legal authority to require whatever reductions it may require as a contingency measure. As EPA has previously stated, ''all contingency measures must be fully adopted rules or measures.'' 62 FR 15844, 15846 (April 3, 1997). The fact that the State or Federal government has already exercised that authority is irrelevant because, as noted above, contingency measures must ''take effect

without further action by the State or [EPA].'' Section 172(c)(9). Thus, by definition, the State necessarily will have already exercised its legal authority to require reductions as a contingency measure before the measure is triggered. It does not matter whether or not a specific contingency measure is already required by law, as long as the emissions reductions that will result from that contingency measure have not been accounted for in the attainment and reasonable further progress demonstrations. If the reductions from the contingency measure are not available for any other use, then they are surplus that is set aside in the event reasonable further progress or attainment is not achieved.

A key element of a valid contingency measure reduction is that the State may not use the reduction in its attainment or reasonable further progress demonstrations if it is already using the reduction as a contingency measure. Those demonstrations must account for the actual emissions reductions that will make reasonable further progress towards, and achieve attainment of the NAAQS in the absence of contingency measures.

I. Transportation Conformity

Transportation conformity is required under CAA section 176(c) (42 U.S.C. 7506(c)) to ensure that Federally supported highway and transit project activities are consistent with (''conform to'') the purpose of the SIP. Conformity currently applies to areas that are designated nonattainment, and those redesignated to attainment after 1990 (''maintenance areas'' with plans developed under CAA section 175A) for the following transportation-related criteria pollutants: ozone, particulate matter ($PM_{2.5}$ and PM_{10}), carbon monoxide (CO), and nitrogen dioxide (NO_2). Conformity to the purpose of the SIP means that transportation activities will not cause new air quality violations, worsen existing violations, or delay timely attainment of the relevant NAAQS (or ''standards'').

The final $PM_{2.5}$ implementation rule does not contain any revisions to the transportation conformity regulation. The EPA addressed the transportation conformity requirements that apply in $PM_{2.5}$ nonattainment and maintenance areas in three separate rulemakings as described below.

First, on July 1, 2004, EPA published a final rule (69 FR 40004) that addressed the majority of requirements that apply in $PM_{2.5}$ areas including:

- Regional conformity tests to be used in conformity determinations both before and after SIPs are submitted and motor vehicle emissions budgets are found adequate or are approved;
- Consideration of direct $PM_{2.5}$ emissions in regional emissions analyses;
- Consideration of re-entrained road dust in $PM_{2.5}$ regional emissions analyses;
- Consideration of transportation construction-related fugitive dust in $PM_{2.5}$ regional emissions analyses; and
- Compliance with $PM_{2.5}$ SIP control measures.

Then on May 6, 2005, EPA promulgated a final rule (70 FR 24280) that specified the transportation-related $PM_{2.5}$ precursors and when they apply in transportation conformity determinations in $PM_{2.5}$ nonattainment and maintenance areas.

Finally, on March 10, 2006, EPA promulgated a final rule (71 FR 12468) that establishes the criteria for determining which transportation projects must be analyzed for local particle emissions impacts in $PM_{2.5}$ and PM_{10} nonattainment and maintenance areas. If required, an analysis of local particle emissions impacts is done as part of a transportation project's conformity determination.

Transportation conformity for the $PM_{2.5}$ standards began applying in $PM_{2.5}$ nonattainment areas on April 5, 2006, one year after the effective date of EPA's $PM_{2.5}$ nonattainment designations (i.e., April 5, 2005). CAA section 176(c)(6) and 40 CFR 93.102(d) provide a one-year grace period before conformity applies in areas newly designated nonattainment for a new standard. $PM_{2.5}$ SIP submissions such as RFP and attainment demonstrations would identify motor vehicle emissions budgets (''budgets'') for direct $PM_{2.5}$ or $PM_{2.5}$ precursors, as described below. These budgets would be used for satisfying transportation conformity requirements, once the budgets are found adequate or the SIP containing the budgets is approved by EPA. For example, state and local agencies would consider during the development of the $PM_{2.5}$ SIP whether reductions of on-road mobile source $S0_2$ emissions are a significant contributor to an area's $PM_{2.5}$ air quality problem, and if so, establish a $S0_2$ motor vehicle emissions budget for transportation conformity purposes.

The EPA has previously addressed its intentions regarding when budgets must be established in $PM_{2.5}$ SIPs for transportation conformity purposes. RFP plans, attainment demonstrations, and maintenance plans must include a budget for direct $PM_{2.5}$ emissions, except for certain cases as described below. All $PM_{2.5}$ SIP budgets would include directly emitted $PM_{2.5}$ motor vehicle emissions from tailpipe, brake wear, and tire wear. States should also consider whether re-entrained road dust or highway and transit construction dust are significant contributors and should be included in the $PM_{2.5}$ budget. For further information, see 40 CFR 93.102(b) and 93.122(f) of the transportation conformity regulation, as well as Sections VIII–X of the July 1, 2004 conformity rule preamble at 69 FR 40031–40036.

Under certain circumstances, directly emitted $PM_{2.5}$ from on-road mobile sources may be found an insignificant contributor to the air quality problem and NAAQS. Section 93.109(k) of the conformity rule states that ''[s]uch a finding would be based on a number of factors, including the percentage of motor vehicle emissions in the context of the total SIP inventory, the current state of air quality as determined by monitoring data for that NAAQS, the absence of SIP motor vehicle control measures, and historical trends and future projections of the growth of motor vehicle emissions.'' The EPA discussed its intentions for applying the insignificance provision in the July 2004 final rule (69 FR 40061–40063).

In the May 6, 2005 final rule, EPA provided details regarding when states must establish SIP budgets for any $PM_{2.5}$ precursor (i.e., NO_x, VOCs, $S0_2$ and ammonia). If through the SIP process a state concludes that on-road mobile source emissions of one or more precursors are significant (i.e. need to be addressed in order to attain the $PM_{2.5}$ standards as expeditiously as practicable), then EPA expects that the state will include a budget in the SIP for each of the relevant precursors. (70 FR 24287) The EPA also noted in the May 2005 conformity rule that, if inventory and modeling analyses demonstrating RFP, attainment or maintenance indicate a level of emissions of a precursor that must be maintained to demonstrate compliance with the applicable requirement, then that level of emissions should be clearly identified in the SIP as a budget for transportation conformity purposes, even if the SIP does not establish particular controls for the given precursor. If the state fails to identify such a level of emissions as a budget, EPA will find the submitted SIP budgets inadequate because the SIP fails to clearly identify the motor vehicle emissions budget as required by the conformity rule (40 CFR 93.118(e)(4)(iii)). (70 FR 24287) In determining whether the on-road mobile source emissions of a $PM_{2.5}$ precursor are significant, state and local agencies would use the criteria for insignificance findings provided in 40 CFR 93.109(k)

of the transportation conformity regulation. A further discussion of the criteria to be considered in establishing $PM_{2.5}$ precursor budgets is contained in the May 2005 final transportation conformity rule (70 FR 24282–24288). If state and local agencies conclude that on-road sources of a precursor are not a significant contributor to the area's $PM_{2.5}$ air quality problem, as described above, motor vehicle emissions budgets would not be established even though emissions may be addressed in the area's RFP plan, attainment demonstration and/or maintenance plan.

J. General Conformity

a. Background

The General Conformity regulations promulgated in 1993 establish an implementation process where Federal agencies are responsible for making their own determination of conformity with State implementation plans (SIPs), and EPA plays an advisory role. Recognizing that it was impracticable to evaluate all Federal actions for conformity, EPA created a number of exemptions in those regulations for actions with insignificant or not reasonably foreseeable emission increases, including exemptions for Federal actions with emissions below specified *de minimis* levels. When a Federal agency must demonstrate conformity for an action, the regulations provide several methods for making that demonstration. With the designations of $PM_{2.5}$ nonattainment areas on April 5, 2005, requirements for demonstrating conformity become effective in those areas on April 5, 2006.

On July 17, 2006 EPA issued a final rule (71 FR 40420) to amend the General Conformity Regulations to establish *de minimis* levels for $PM_{2.5}$ for the General Conformity program. The final rule established 100 tons/year of direct $PM_{2.5}$ emissions and its precursors as the *de minimis* level where the General Conformity regulations would apply in $PM_{2.5}$ nonattainment areas. In the process of finalizing the *de minimis* level for $PM_{2.5}$ three comments were received. One commenter was concerned about emissions from burning by Federal agencies. Another commenter proposed that the *de minimis* level for emissions of direct $PM_{2.5}$ should be set significantly lower than 100 tons—in the range of 25–50 tons per year (TPY) in areas that are likely to attain the $PM_{2.5}$ national ambient air quality standard within 5 years, and a level of 10–25 TPY in areas that are likely to take more than 5 years to achieve the national ambient air quality standard. A third commenter supported the proposed *de minimis* level.

The final rule revises the tables in sub-paragraphs (b)(1) and (b)(2) of the General Conformity Regulations by adding a *de minimis* emission level for $PM_{2.5}$ and its precursors. This action maintained our past policy of consistency between the conformity *de minimis* emission levels and the size of a major stationary source under the New Source Review program (70 FR 65984). These levels are also consistent with the levels promulgated for Reasonably Available Control Technology applicability levels for volatile organic compound and nitrogen oxide emissions in subpart 1 areas under the 8-hour ozone implementation strategy (68 FR 32843). Since EPA is not finalizing any classifications for the $PM_{2.5}$ nonattainment areas, we did not establish differing $PM_{2.5}$ *de minimis* emission levels for higher classified nonattainment areas.

b. Comments and Responses

Comment: One commenter requests that EPA communicate to all Federal agencies the value of the agencies advising the States as soon as possible of any planned future projects in nonattainment areas that may be above the General Conformity *de minimis* values or that will have to be evaluated to show that they are below *de minimis*. This is for projects that are very likely to proceed. The aim is to consider these future emissions in any growth projections during SIP development since such growth may not be anticipated well by the available growth model (E–GAS). States can communicate with existing Federal facilities now concerning this issue.

Response: The EPA sees the value in Federal agencies working with States to anticipate growth in emissions and include those anticipated emissions in the applicable SIP. The EPA is in the process of proposing regulatory amendments to the General Conformity regulations that provide a framework for Federal facilities to work with States to account for facility-wide emissions in SIPs and to include Federal facility emissions in future SIPs. The EPA anticipates that these rule amendments should be proposed before the end of summer 2006.

Comment: Some commenters stated that the *de minimis* level for $PM_{2.5}$ for conformity applicability should be less than 100 tons per year. A level of 50 tons per year was suggested for direct $PM_{2.5}$ emissions.

Response: Similar comments were received when the $PM_{2.5}$ *de minimis* level was proposed on April 5, 2006. The response to those comments can be found in the preamble to the final rule setting the *de minimis* level for $PM_{2.5}$ at 71 FR 40420.

Comment: Are the precursors for general conformity consistent with this rulemaking or with the transportation conformity rulemaking?

Response: The precursors for general conformity are generally consistent both with this rule and the transportation conformity rule. The only difference between the transportation rule and this rule is that SO_2 is not considered a precursor for transportation conformity determinations that occur prior to a $PM_{2.5}$ SIP unless EPA or the State air agency finds on-road mobile source emissions significant. For more information, see the May 6, 2005 transportation conformity rule on $PM_{2.5}$ precursors at 70 FR 24283. Since general conformity includes analysis of stationary sources the general conformity rule requires SO_2 as a precursor both before and after a $PM_{2.5}$ SIP is submitted.

Comment: When will rulemaking containing the *de minimis* levels for $PM_{2.5}$ and for the precursors be issued? There is some confusion, since the proposed rule says that states should assume 100 tpy for all $PM_{2.5}$ pollutants, as this would make it consistent with the levels for NO_X and VOC for the subpart 1 areas under 8-hour ozone. However, since New Jersey's classification is moderate under the 8-hour ozone standard and we are in an Ozone Transport Region, the *de minimis* level for VOC is 50 tons per year.

Response: On July 17, 2006 EPA issued a final rule (71 FR 40420) to amend the General Conformity Regulations to establish *de minimis* levels for $PM_{2.5}$ for the General Conformity program. The final rule established 100 tons/year of direct $PM_{2.5}$ emissions and its precursors as the *de minimis* level where the General Conformity regulations would apply in $PM_{2.5}$ nonattainment areas. Since EPA is not finalizing any classifications for the $PM_{2.5}$ nonattainment areas, we did not establish differing $PM_{2.5}$ *de minimis* emission levels for based on a classification scheme.

Comment: If a Statement of Conformity has been issued on a project and if the project has not been completed to date, are they required to address $PM_{2.5}$ prior to completion of the project or will they be grandfathered in?

Response: If a Federal action has completed a conformity determination and the action has started (regardless of whether the project is complete or not) then no new determination is needed. If

the conformity determination was completed, but the action did not start in 5 years a new determination is needed under the general conformity rules.

Comment: What guidance should states use to establish budgets for large facilities or military bases?

Response: The EPA has not issued any guidance for States and Federal facilities to establish facility-wide budgets in the applicable SIP. There is nothing in the General Conformity regulations preventing this approach which would allow Federal actions that do not increase total facility emissions over the budget in the SIP from determining the action conforms on the basis of its compliance with the budget limit. The EPA sees this practice as a positive step to encourage States and Federal agencies to work together to account for emissions in a SIP so they conform with the purposes and goals of the SIP. The EPA intends to address the approach and provide guidance in planned revisions to the General Conformity regulations which are expected to be proposed in 2006.

K. Emission Inventory Requirements

a. Background

Emission inventories are critical for the efforts of State, local, tribal and federal agencies to attain and maintain the NAAQS that EPA has established for criteria pollutants including $PM_{2.5}$. Pursuant to its authority under section 110 of Title I of the CAA, EPA has long required States to submit emission inventories containing information regarding the emissions of criteria pollutants and their precursors. The EPA codified these requirements in 40 CFR part 51, subpart Q in 1979 and amended them in 1987.

The 1990 CAAA revised many of the provisions of the CAA related to attainment of the NAAQS and the protection of visibility in mandatory Class I Federal areas (certain national parks and wilderness areas). These revisions established new emission inventory requirements applicable to certain areas that were designated nonattainment for certain pollutants. In the case of particulate matter, the emission inventory provisions are in the general provisions under Section 172(c)(3).

In June 2002, EPA promulgated the Consolidated Emissions Reporting Rule (CERR) (67 FR 39602; June 10, 2002), 40 CFR part 51 subpart A. The CERR consolidated the various emissions reporting requirements that already existed into one place in the CFR, established new reporting requirements for $PM_{2.5}$ and ammonia, and established new requirements for the statewide reporting of area source and mobile source emissions.

The CERR established two types of required emission inventories: annual inventories, and 3-year cycle inventories. The annual inventory requirement is limited to reporting statewide emissions data from the larger point sources. For the 3-year cycle inventory, States need to report data from all of their point sources plus all of the area and mobile sources on a statewide basis. A special case existed for the first 3-year cycle inventory for the year 2002 which was due on June 1, 2004.

The EPA issued guidance suggesting that 2002 be used as the Base Year for 8-hour ozone, $PM_{2.5}$ and regional haze planning efforts (November 18, 2002 EPA memorandum ''2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, $PM_{2.5}$ and Regional Haze Programs'' *http://www.epa.gov/ttn/chief/eidocs/2002baseinven_102502new.pdf*).

States should estimate mobile source emissions by using the latest emissions models and planning assumptions available at the time the SIP is developed. Information and guidance on the latest emissions models is available at *http://www.epa.gov/otaq/stateresources/transconf/policy.htm#models* and at *http://www.epa.gov/otaq/models.htm.*

By merging the information on point sources, area sources and mobile sources into a comprehensive emission inventory, State, local and tribal agencies may do the following:

- Set a baseline for SIP development.
- Measure their progress in reducing emissions.
- Have a tool to support future trading programs.
- Answer the public's request for information.

The EPA uses the data submitted by the States to develop the National Emission Inventory (NEI). The NEI is used by EPA to show national emission trends, as modeling input for analysis of potential regulations, and other purposes.

Most importantly, States need these inventories to help in the development of control strategies and demonstrations to attain the annual and 24-hour $PM_{2.5}$ NAAQS. In April 1999, EPA published the ''Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations,'' EPA–454/R–99–006. The EPA updated this guidance in November 2005.[46] The current version of this guidance is available at: *http://www.epa.gov/ttn/chief/eidocs/eiguid/index.html.* The EPA developed this guidance document to complement the CERR and to provide specific guidance to State and local agencies and Tribes on how to develop emissions inventories for 8-hour ozone, $PM_{2.5}$, and regional haze SIPs. While the CERR sets forth requirements for data elements, EPA guidance complements these requirements and indicates how the data should be prepared for SIP submissions.

The SIP inventory must be approved by EPA as a SIP element and is subject to public hearing requirements, whereas the CERR is not. Because of the regulatory significance of the SIP inventory, EPA will need more documentation on how the SIP inventory was developed by the State as opposed to the documentation required for the CERR inventory. In addition, the geographic area encompassed by some aspects of the SIP submission inventory will be different from the statewide area covered by the CERR emissions inventory. The CERR inventory was due June 1, 2004, while the SIP inventory due date is later. Because of this time lapse, the State may choose to revise some of the data from the CERR when it prepares its SIP inventory to account for improvements in emissions estimates. If a State's 2005 emission inventory (or a later one) becomes available in time to use for timely development of a nonattainment area SIP, then that inventory can be used. We also encourage the cooperation of the Tribes and the State and local agencies in preparing their emissions inventories.

b. Final Rule

In the proposed rulemaking, in § 51.1008(a), to meet the emission inventory requirements of section 172(c)(3), EPA proposed to require submission of the CERR inventories as well as ''any additional emission inventory information needed to support an attainment demonstration and RFP plan ensuring expeditious attainment of the annual and 24-hour $PM_{2.5}$ standards.'' Section 51.1008(b) set forth specifications for baseline emissions inventories for attainment demonstrations and RFP requirements. Section 51.1008 of the final rule reflects our proposed rule but is different from the draft regulatory text. The proposal did not specify a deadline for

[46] Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations,'' (EPA–454/R–05–001, November 2005.

submission of the emission inventory. To ensure clarity, the final rule contains language addressing the deadline for submission of emissions inventories for nonattainment areas under section 172(c)(3) and section 172(b), and reflects the statutory requirement of no later than 3 years after designation of the area. See § 51.1008(a). In addition, § 51.1008(a)(1) of the proposed rule has been changed for purposes of clarification. The proposal referred to the requirement to submit statewide emission inventories under the (CERR), contained in 40 CFR part 51, subpart A. The final regulatory text clarifies this to refer to the requirements for data elements under 40 CFR part 51, subpart A. The EPA did not intend that the emissions inventories developed under the CERR, which are statewide, would be appropriate for and satisfy all aspects of SIP inventories developed for SIP submissions. Section 51.1008(b) has a minor change to clarify that this subsection refers to the inventories required for submission under paragraph (a) of section 51.1008, and also clarifies the reference to 40 CFR Part 51 subpart A, which currently contains the CERR. In addition, section 51.1008(b) as finalized provides that ''The baseline emission inventory for calendar year 2002 or other suitable year shall be used for attainment planning and RFP plans for areas initially designated nonattainment for the $PM_{2.5}$ NAAQS in 2004.'' The EPA added this flexibility to be consistent with EPA's ozone implementation rule, and to enable a State to use a more recent and improved base year inventory if it is completed in time to allow for timely development of the attainment plan. As noted above, we expect that States will consult the guidance document titled *Emission Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (''NAAQS'') and Regional Haze Regulations,* November 2005,and submit inventories that are appropriate for the geographic area at issue and consistent with regulations and this guidance. We expect the States to include in their SIP submission documentation explaining how the emissions data were calculated.

In the proposed rulemaking, EPA asked ''What emission inventory requirements should apply under the $PM_{2.5}$ NAAQS.'' Several specific questions followed this general question to assess whether or not additional emission inventory requirements or guidance are needed to implement the proposed standard. It was noted in the proposal that the basis for EPA's emission inventory program is specified in the Consolidated Emissions Reporting Rule (CERR) and the related guidance document titled *Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations.*

Subsequent to the proposed rulemaking, EPA proposed the Air Emissions Reporting Rule (AERR) at 71 FR 69 (Jan. 3, 2006). The AERR would update CERR reporting requirements by consolidating and harmonizing new emissions reporting requirements with pre-existing sets of reporting requirements under the Clean Air Interstate Rule (CAIR) and the NO_X SIP Call. At this time, EPA is reviewing comments submitted on the AERR proposal and expects to finalize this rulemaking during calendar year 2007. The AERR is expected to be a means by which the Agency will implement additional data reporting requirements for $PM_{2.5}$ SIP emission inventories. Since the AERR rulemaking is in progress, EPA believes it is appropriate to defer responding to certain comments on the proposed $PM_{2.5}$ Implementation Rule related to data reporting and emission inventory requirements that were discussed in the AERR proposal. Those comments will be addressed in the final AERR rulemaking. Significant comments that are separable from the AERR rulemaking and relate to data reporting and emission inventory requirements for the $PM_{2.5}$ NAAQS are addressed below and in EPA's Responses to Comments document.

With respect to SIP emission inventory requirements under this rulemaking, EPA recognizes NO_X, SO_2, VOCs, and ammonia as potential precursors of $PM_{2.5}$ because these pollutants can contribute to the formation of $PM_{2.5}$ in the ambient air. To provide a technical foundation for understanding contributions to $PM_{2.5}$ nonattainment problems and for identifying potential future measures to reduce $PM_{2.5}$ concentrations, EPA is requiring under 40 CFR part 51 subpart A and 40 CFR 51.1008 of this rule that States develop and submit inventories for direct $PM_{2.5}$ and all precursors of $PM_{2.5}$. This requirement stands apart from the policies in this rule regarding the required treatment of various precursor emissions in the development of control strategies for attaining the $PM_{2.5}$ standards. With respect to the latter requirements, EPA has not made a finding that all precursors should be evaluated for potential control measures in each specific nonattainment area. The policy approach in the rule instead requires evaluation of control measures for direct $PM_{2.5}$ and sulfur dioxide in all areas, and describes general presumptive policies that NO_X sources need to be evaluated for control measures in all areas unless findings of insignificance are made, but that control measure evaluations are not required for sources of ammonia and VOC unless findings of significance are made. The rule also provides a mechanism by which the State and/or EPA can make an area-specific demonstration to reverse the general presumption for these three precursors. (See section II.A.8 for additional discussion on these issues.)

c. Comments and Responses

1. Should EPA Specify an Inventory Approval Process?

Comment: Several commenters indicated that the current process of approving SIP inventories by EPA regional offices is appropriate and did not believe that additional approval requirements were necessary. Some commenters noted that flexibility is needed to address regional concerns. Several commenters noted that SIP emission inventories may include requirements or information in addition to data required by the Consolidated Emissions Reporting Rule (CERR). One commenter observed that States routinely develop information outside the CERR for purposes of their SIP development and that additional requirements should not be defined by EPA. Another commenter recommended that requirements for nonattainment area emission inventories be incorporated in the CERR or AERR. A few commenters felt that additional guidance was needed on the SIP emission inventory approval process.

Response: The SIP emissions inventory is a plan provision that must be approved by EPA under section 110(k) of the CAA and is subject to public hearing requirements pursuant to section 110(a)(2). The EPA believes that it need not further specify a SIP approval process for emissions inventories beyond that set forth in the statute, regulation (51.1008), other related sections of this rulemaking and EPA's current guidance. The EPA agrees with many of the commenters that the approval process for SIP emission inventories need not be further defined and that approval should be conducted at the regional level to provide flexibility to address regional concerns. The EPA also agrees that use of Quality Assurance Project Plans developed for each state will be helpful in establishing the proper approval process. The EPA

addresses the issue of what data elements are needed for SIP approval in the responses to comments below, including the responses to comments under Issue 2, below.

As noted by two commenters EPA describes procedures for approval of SIP inventories in a document titled *Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations,* November 2005. Section 2.5, Inventory Approval, references a memorandum titled *Public Hearing Requirements for 1990 Base-Year Emissions Inventories for Ozone and CO Nonattainment Areas, September 29, 1992.* The EPA intends to use the procedures discussed in the guidance and memorandum to the extent that they are applicable to approval of $PM_{2.5}$ emission inventories submitted as part of the SIP. 40 CFR 51.1008 sets forth the requirements for emissions inventories under section 172(c)(3), which will be reviewed in the context of the SIP approval process. See also 40 CFR 51.1007 and 51.1009 regarding attainment demonstrations and RFP plans. Thus, EPA believes that its existing SIP approval process is adequately described in statute, regulation and guidance, and that it provides flexibility to deal with issues that arise in individual nonattainment areas.

2. Are the Data Elements Specified Within the CERR Sufficient To Develop Adequate SIPs? For Example, in the Determination of RACT, Should More Information on Existing Control Devices Be Required?

Comment: Several commenters recommended that any additional reporting requirements should be addressed through the CERR/AERR and associated guidance and that no additional reporting requirements should be specified in the Rule. Another commenter stated that more detail concerning control equipment would be helpful but was concerned about the additional burden on industry compared to the benefit to State and local agencies, and suggested that this would be further addressed in the context of comments on the AERR. One commenter believed that the reporting requirements within the CERR are sufficient to develop a $PM_{2.5}$ SIP for most areas but noted that nonattainment areas may require additional inventory information which will need evaluation on a case-by-case basis. The commenter further stated that any additional inventory requirements should be identified during the SIP development process, in cooperation with the EPA regional office, and should not be part of this rule.

Response: In section 40 CFR 51.1008(a)(1) of the final rule, EPA incorporates the requirements for data elements required under 40 CFR part 51, subpart A, which contains the CERR, for inventories submitted under this section. The EPA notes, however, that the issue of whether to require additional reporting requirements beyond those required in the CERR is currently being addressed in the Air Emissions Reporting Rule (AERR) 71 FR 69 (January 3, 2006). At this time EPA believes that the requirements for data elements under the CERR, in conjunction with the other provisions of 40 CFR 51.1008, as well as 40 CFR 51.1007 and 51.1009, are generally adequate to meet the needs for $PM_{2.5}$ nonattainment emission inventory SIP development. The AERR as proposed includes additional provisions which may be helpful for $PM_{2.5}$ SIP emission inventory development. The EPA will address this aspect of the AERR, including comments received in this rulemaking on the issues raised and the additional elements proposed in the AERR, in the final AERR rulemaking. This final rule indicates that States shall include data elements for $PM_{2.5}$ inventories as required under 40 CFR part 51, subpart A. In addition, 40 CFR 51.1008(a)(2) requires that States submit ''any additional emission inventory information needed to support an attainment demonstration and RFP plan ensuring expeditious attainment of the annual and 24-hour $PM_{2.5}$ standards.'' See also 40 CFR 51.1007 and 51.1009. Thus States should be aware that data elements in addition to those required under the CERR may be needed to support attainment demonstrations and RFP inventories. Additional data elements needed for other SIP emission inventory purposes should be handled on a case-by-case basis. Because of the nature of SIP development, which varies depending on the nature and needs of individual areas, it may not be possible to require a level of detail in regulations that will enable a ''one-stop-shop'' information request as suggested by one of the commenters.

As recommended by one commenter, guidance on reporting requirements is contained in *Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations* (EPA–454/R–05–001, November 2005). For example, Section 3.2.1 for Pollutant and Pollutant Precursors to be Inventoried presents guidance to states on $PM_{2.5}$ pollutants and their components that should be reported for $PM_{2.5}$ SIP development. See also section 5, Emission Inventory Development, and other related sections of the guidance.

With respect to the comment on additional detail on control requirements, see also EPA's Response to Comment Document.

3. Is the Current Approach for Reporting Specific Pollutants Sufficient, or Should EPA Require More Specific Emission Component Reporting Such as Groups of Compounds or Reporting of Elemental Carbon and Organic Carbon?

Comment: Currently the CERR requires the reporting of SO_2, VOC, NO_X, CO, Pb, PM_{10}, $PM_{2.5}$, and NH_3. VOC and PM are speciated by the emissions processing models based on speciation profiles for specific source categories. Most commenters supported retaining the existing reporting requirements under the CERR. Others encouraged expansion of the requirements to include reporting of specific organic compounds and organic fractions although some thought this should be a requirement while others thought it should be optional. One commenter thought that EPA should work with industry trade groups to develop and improve the speciation profiles of the most important source categories rather than asking the state and local agencies to characterize VOC and PM species. Several commenters thought that EPA should encourage the reporting of PM components (filterable, condensable and total) for development of control strategies and attainment demonstrations. Another commenter noted that including condensable emissions raises ''uncertainty'' issues and urged EPA to devote resources to developing better test methods. One commenter believed that in addition to reporting $PM_{2.5}$ and its components, states should report all precursors to $PM_{2.5}$ (SO_2, NO_X, ammonia and VOC).

Response: The EPA agrees with the commenters who argued that the need for additional speciation should be determined based on specific SIP needs. 40 CFR part 51, subpart A which contains the CERR, does not require reporting of specific compounds or compound groups nor does it require reporting of organic and elemental carbon fractions. As discussed in the response to comment above, EPA believes that the requirements for data elements contained in 40 CFR part 51 subpart A, in conjunction with the provisions of 40 CFR 51.1008, are generally adequate to meet the needs for $PM_{2.5}$ nonattainment emissions

inventory SIP development. Section 51.1008(a)(1) applies the data element requirements contained in 40 CFR part 51 subpart A. Section 51.1008(a)(2) requires States to submit ''any additional emission inventory information needed to support an attainment demonstration and RFP plan ensuring expeditious attainment of the annual and 24-hour $PM_{2.5}$ standards.'' Thus data elements in addition to those required under the CERR may be needed to support attainment demonstrations and RFP inventories under 40 CFR 51.1008(a)(2). Additional data elements needed for other SIP emission inventory purposes should be handled on a case-by-case basis. Where States need to develop speciated emissions for $PM_{2.5}$ SIP emission inventories, EPA provides guidance in the document titled *Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Ozone Regulations,* November 2005. Section 3.2.1, Pollutants and Pollutant Precursors to be Inventoried identifies pollutants and their components to be reported for $PM_{2.5}$ SIPs. Section 3.3.5, Speciation Procedures, discusses the preferred approach for speciating $PM_{2.5}$ emission inventories for use in ambient air quality simulations. The approach discussed in the guidance is application of emission models which use speciation profiles to estimate the mass of specific compounds and compound groups for VOC and elemental and organic carbon fractions for PM. The EPA encourages further research and development of technical tools to better characterize emissions inventories for specific VOC compounds and to determine the extent of specific VOC compounds and organic PM mass. The EPA also encourages States to continue efforts to refine their ammonia inventories. See sections II.A.3 and II.A.4 of the Preamble.

As discussed in the guidance document, EPA encourages reporting of organic and elemental fractions of $PM_{2.5}$ by state agencies (see Section 3.2.1, Pollutants and Pollutant Precursors to be Inventoried). While elemental or black carbon (EC/BC) and organic carbon (OC) will be identified in default speciation profiles, more locally-specific data should be collected where available as an input to model preprocessing. Where such data are available, they should be provided to EPA to help in improving EPA's speciation profiles. Certain organic gases have been identified as precursors to secondary organic aerosols (SOA). Toluene, xylene and ethyl benzene are known to be important SOA precursors. Additional organic gases may be identified by ongoing research. While these gases will be identified in default speciation profiles, more locally-specific data should be collected, where available, as an input to model preprocessing. State, local and Tribal agencies can contact EPA's EIAG for more information.

EPA agrees with the comment that it should take the lead in updating VOC and PM profiles for most important source categories. The Agency is close to completing a multi-year effort to update the SPECIATE database. SPECIATE is EPA's repository of Total Organic Compound (TOC) and PM speciated profiles for a wide variety of sources. The profiles in this system are provided for air quality dispersion modeling and as a library for source-receptor and source apportionment type models. This recent initiative to update SPECIATE was needed because speciated emissions profiles continue to be developed and the data in the existing EPA database (SPECIATE 3.2) was becoming outdated.

This work was coordinated with interested parties including industry through an Agency sponsored workgroup. It has depended largely on the collection and review of existing profile data to accomplish, as the commenter suggests, delivering the best results for the least amount of resources spent. Previously, these data were not widely available to emission inventory developers and lacked the quality assurance review and evaluation needed to develop profiles used by emissions models to generate speciated emissions. As suggested by the commenter, the workgroup was used to help prioritize source categories for investigation to ensure that updates to existing profiles and development of new profiles focused on areas of greatest need.

SPECIATE v4.0 contains more than 2500 source profiles and is currently undergoing peer review. The EPA expects the final work product to be available for use by emission inventory preparers during early calendar year 2007 and it will be distributed through EPA's CHIEF Web site.

The EPA agrees with a commenter who noted that in order to meet the requirements under section 172(c) of the CAA for ''a comprehensive, accurate, current inventory * * *,'' condensable emissions of $PM_{2.5}$ and $PM_{2.5}$ precursors are important to support development of local control strategies and attainment demonstrations. The EPA believes that the final rule provides for the submission of $PM_{2.5}$ nonattainment area inventories meeting the requirements of section 172(c)(3).

Section 51.1008(a)(1) requires that States submit emission inventories for $PM_{2.5}$ that satisfy the data elements reporting requirements under 40 CFR part 51 subpart A, which contains the CERR. The CERR requires reporting of ''Primary $PM_{2.5}$'' which is defined as the sum of the filterable and condensable portions of $PM_{2.5}$. Therefore, SIP base year inventories will include the condensable fraction of PM which was of concern to several commenters. The CERR also requires reporting of SOx, NO_X, ammonia and VOC which are potential precursors to $PM_{2.5}$. EPA notes that the AERR as proposed would require reporting of the same precursors and would also require reporting of Primary $PM_{2.5}$. However, the proposed AERR requires the reporting of the filterable and condensable fractions of $PM_{2.5}$ (optional under the CERR) in addition to the primary $PM_{2.5}$ total mass. The EPA will address this requirement in its final rulemaking on the AERR.

As noted above, in addition to the data element requirements under section 51.1008(a)(1), under section 51.1008(a)(2) States must submit ''any additional emission inventory information needed to support'' an attainment demonstration and RFP plan. Thus States should be aware that data elements in addition to those required under the CERR may be needed to support attainment demonstrations and RFP inventories under 40 CFR Part 51.1008(a)(2). Additional data elements needed for other SIP emission inventory purposes should be handled on a case-by-case basis.

The EPA is aware of the issues raised by one commenter regarding measurement uncertainty for condensable PM. This issue is addressed in detail under Section II.L of the preamble (''Condensable particulate matter test methods and related data issues,''). We believe that for purposes of emissions inventories and attainment demonstrations, States should continue to describe the impacts of baseline emissions and develop future air quality strategies using information available on primary $PM_{2.5}$ emissions, including condensable $PM_{2.5}$. However, with respect to developing enforceable emissions limits for condensable $PM_{2.5}$ emissions, the final rule reflects EPA's adoption of a transition period during which we will allow time for development of emissions limits for condensable $PM_{2.5}$. See 40 CFR 51.1002(c).

For additional comments and responses related to speciation issues,

see the Response to Comments Document.

4. Should EPA Require That States Develop Their Own Estimates for Area and Mobile Source Emissions?

Comment: The CERR allows states to adopt EPA developed emission estimates from area and mobile sources in lieu of making those estimates themselves if they accept these estimates for their emission inventory. One commenter thought that EPA should require States to develop their own estimates for area and mobile sources based on the specified 2002 base year. Three commenters thought that the existing process (under the CERR) was adequate. One of the commenters expressed concerns about the reporting burden for States if they were required to compile their own mobile and area source inventories. Another commenter did not believe that States should be required to submit data on area and mobile sources but noted that many States would continue to run the MOBILE model for onroad mobile sources and calculate area source data for SIP emission inventories. Two of the commenters thought that the existing process provided flexibility needed by States to focus on source categories of most concern and address problematic areas with special inventory needs. One commenter recommended that EPA continue developing models for area and mobile sources.

Response: The EPA strongly encourages states to submit their own estimates for area (nonpoint) and mobile sources unless they can establish that it is impracticable to do so, given time and resources. We will continue, in appropriate circumstances, to allow a State to use EPA-developed emission estimates for mobile and nonpoint sources in lieu of making those estimates itself if the State accepts the estimates for its emission inventory. While this has been the case with respect to reporting under the CERR for the 3-year cycle inventories, for development of emission inventories to support $PM_{2.5}$ SIPs, the ability to rely on EPA-developed emission estimates for development of emission inventories to support $PM_{2.5}$ SIPS is more complex and problematic. For mobile sources, the practical use of these EPA-developed mobile source inventories in a SIP may be very limited. While EPA has developed inventories for 2002, states will still have to develop attainment year inventories, including projections of future activity and the effects of control measures. For mobile sources, future year inventories are not developed by simply growing a base year inventory, but instead are developed by running an emissions model with appropriate inputs for the future year. In order to develop an attainment demonstration that accurately accounts for the change in emissions from the base year to the attainment year, inventories for both of those years will need to be developed using consistent methods and modeling assumptions. For mobile sources especially, it may be very difficult for states to replicate the methods used by EPA for the base year when creating the attainment year inventory.

In addition, states cannot use the EPA developed inventories for the base year if newer models or planning assumptions are available at the time they begin working on the SIP. For example, if new or better information about the composition of the local fleet of highway vehicles in the base year becomes available to the state after the EPA developed inventories were created, that information should be used by the state to create a new base year inventory.

Given the need for emissions modeling for mobile sources in the projection year, the need for consistency in tools and methods between the base year and attainment year, and the need to use latest available models and planning assumptions, EPA believes that most if not all states will choose to develop their own base year inventories for mobile sources.

With respect to nonpoint (area) source emissions, States must make every effort, consistent with available timing and resources to ensure that their area source emission inventories are as accurate as possible. While EPA prepares a national area source emission inventory that covers all counties, it is designed for national analyses. EPA does not have access to the more detailed information available to States that is used to develop an area source inventory. Therefore, states should develop as much of their area source inventory as possible using local and State information, and in particular should develop the inventory for the most significant area source categories which are critical to ensuring overall accuracy. Where time and resources preclude a State from developing the estimates for less-critical area source categories, the State may rely on EPA-developed area source emissions information for those categories.

The EPA points out that although guidance has recommended that 2002 be used as the base year for emissions inventories for states initially designated nonattainment in 2004–5, states remain free to use an alternate base year, as appropriate. Section 51.1008(b) provides in relevant part that ''The baseline emission inventory for calendar year 2002 or other suitable year shall be used for attainment planning and RFP plans for areas initially designated nonattainment for the $PM_{2.5}$ NAAQS in 2004.''

EPA agrees with the comment that it should continue to develop models and other emission estimation tools. As an example, EPA's Office of Transportation and Air Quality (OTAQ) is developing a modeling system termed the Motor Vehicle Emission Simulator (MOVES). This new system will estimate emissions for on-road and nonroad sources, cover a broad range of pollutants, and allow multiple scale analysis, from fine-scale analysis to national inventory estimation. When fully implemented MOVES will serve as the replacement for MOBILE6.2 and NONROAD. In addition, as the NEI is reengineered, OAQPS will examine the need for updating emissions estimation guidance materials and developing tools which will assist State agencies in estimating emissions from area source categories. See also EPA's ''Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations,'' November 2005.

5. Other Inventory Issues

The EPA's responses to additional comments concerning emission inventory issues can be found in EPA's Response to Comments Document.

L. Condensable Particulate Matter Test Methods and Related Data Issues

a. Background

As noted in the preamble to the November 1, 2005 proposed rule, certain commercial or industrial activities involving high temperature processes (fuel combustion, metal processing, cooking operations, etc.) emit gaseous pollutants into the ambient air which rapidly condense into particle form. The constituents of these condensed particles include, but are not limited to, organic material, sulfuric acid, and metals. Because condensable emissions exist almost entirely in the 2.5 micrometer range and smaller, these emissions are inherently more significant for $PM_{2.5}$ than for prior particulate matter standards addressing larger particles. Therefore, we believe that it is important that the air quality management of particulate matter promote a comprehensive approach to condensable particulate matter.

We proposed to require a comprehensive inclusion of condensable PM for all aspects of SIP development for $PM_{2.5}$. Under the proposal, EPA would require condensable PM to be considered in the emissions inventories and analyses used in attainment demonstrations. Also under the proposal, any stationary source emissions limits developed to implement RACT or RACM would reflect control and measurement of condensable PM.

We received numerous comments on whether these requirements were unreasonable in light of the current state of knowledge of and uncertainties around the measurement of direct $PM_{2.5}$. Most commenters supported the overall view that condensable PM should be addressed in order to provide a complete air quality management program for $PM_{2.5}$. On the other hand, many commenters raised concerns about the availability and implementation of test methods and related issues about the uncertainties in existing data for condensable $PM_{2.5}$. As a result of the concerns, these commenters believed EPA would be premature in requiring a comprehensive evaluation of condensable $PM_{2.5}$, especially as it related to developing any new emissions limits for stationary sources. In recognition of these concerns, the final rule reflects EPA's adoption of a transition period during which we will assess possible revisions to available test methods and we will allow time for States to update emissions inventories as needed to address direct $PM_{2.5}$ emissions. In this section of the preamble, we outline the elements of the final rule addressing inventories reflecting control of direct $PM_{2.5}$. We also discuss the specific comments raised regarding methods for measuring direct $PM_{2.5}$, both filterable and condensable PM, in implementing the rule. The particular comment areas include defining test methods, quantifying direct $PM_{2.5}$ for inventories, and a transition period for developing effective regulations. Below are also our responses to those comments.

b. Final Rule

For the final rule, EPA addresses two broad issues related to inclusion of condensable PM. The first issue is whether emissions inventories and attainment demonstrations should include the condensable portion of direct $PM_{2.5}$ emissions. The second issue is whether direct $PM_{2.5}$ emissions limitations established by States for purposes of RACT and RACM must include limits on condensable PM emissions or limits on total direct $PM_{2.5}$ that includes the condensable PM fraction.

For purposes of developing emissions inventories and attainment demonstrations, the final rule reflects a requirement to account for significant contributors of direct $PM_{2.5}$ emissions, both filterable and condensable $PM_{2.5}$. We recognize that some States have established inventories consistent with requirements of the consolidated emissions reporting rule (CERR) to report direct $PM_{2.5}$ emissions, including condensable PM, in each inventory revision. While uncertainties remain with significant issues to address related to our current knowledge base on condensable PM emissions, we believe that for purposes of emissions inventories and attainment demonstrations, States should continue to describe the impacts of baseline emissions develop future air quality strategies using information available on direct $PM_{2.5}$ emissions including condensable PM.

With respect to developing enforceable emissions limits for condensable PM emissions, we note that some States have established emissions limits or otherwise require PM emissions testing that includes measurement of condensable PM. We recognize that in some States there remain questions about the viability of available test methods, the availability of representative direct $PM_{2.5}$ emissions data, the uncertainty of the methods used to establish inventories, and the short time frame within which States must develop SIPs. In response we have decided to provide a transition period for developing emissions limits and regulations for condensable $PM_{2.5}$. During this transition period, we will provide technical support to States as requested in establishing effective $PM_{2.5}$ emissions limits and corresponding emissions testing requirements.

As described further below, we will devote resources early during this transition period to assessing and improving the available test methods for condensable PM. During this transition period, we will also solicit the involvement of stakeholders with an interest in conducting emissions testing to collect updated direct $PM_{2.5}$ emissions data. The purpose of these stakeholder projects will be to collect new direct filterable and condensable PM emissions data using methodologies that provide data more representative of source direct $PM_{2.5}$ emissions. The EPA, States, and others will use these data to improve emissions factors and to help define or revise source emissions limits in permits and State implementation plans.

The time required for our stakeholders and EPA to complete the test method assessment will limit the degree to which State and local agencies can address effectively the necessary direct $PM_{2.5}$ regulations in inventories and in the 2008 SIP submittals. In recognition of this, we will not require that the emissions limits included in the 2008 submittals account for the condensable fraction of direct $PM_{2.5}$ or to establish limits for total direct $PM_{2.5}$, including condensable PM.

We will expect States to continue developing more complete inventories with regard to direct $PM_{2.5}$ emissions, particularly for condensable PM, during this transition period. We expect no such allowance period for method assessment or data collection to be necessary for implementing regulations addressing precursor $PM_{2.5}$ emissions.

The period of transition for establishing emissions limits for condensable direct $PM_{2.5}$ will end January 1, 2011. We expect States to address the control of direct $PM_{2.5}$ emissions, including condensable PM, with any new actions taken after January 1, 2011. For example, States must address condensable PM emissions in any direct $PM_{2.5}$ emissions limits resulting from midcourse reviews. Additionally, EPA expects that any direct $PM_{2.5}$ regulations or limits developed under any new NAAQS for particulate matter would also address condensable PM emissions.

Notwithstanding the issues and uncertainties related to condensable PM, EPA encourages States to identify measures for reducing condensable PM emissions, particularly where those emissions are deemed significant contributors to the control strategy needed for expeditious attainment. We wish to clarify that in order to take credit in the SIP for reduction of any such condensable PM emissions, there must be enforceable limitations that ensure that reduction in condensable PM emissions. These enforceable limits could take the form of a limitation on the condensable PM emissions or total direct $PM_{2.5}$ emissions (or a commitment to develop such limitations after the end of the transition period described above). Alternatively, these enforceable limitations could provide for enforceable conditions that ensure that the effect on condensable PM emissions is assured (for example, enforceable limitations on operating temperature, or limits on FGD scrubber operations which have the effect of reducing condensable PM emissions).

c. Comments and Responses

We received many comments on quantification of direct $PM_{2.5}$ emissions particularly about the need to conduct further validations for the available test methods, the availability of direct filterable or condensable $PM_{2.5}$ data or lack thereof for representative baselines, and the procedures for applying baseline data for developing effective regulations.

1. Method 202

Comment: A majority of commenters characterized the performance of Method 202 as lacking in reliability. Some commenters characterized the formation of artifacts in Method 202 as significant and the primary reason for their recommendation to defer the inclusion of condensable particulate matter in the baseline assessments and regulatory development for the initial SIPs. The commenters stated that the principal artifact formed when using Method 202 was the result of SO_2 dissolving in the impinger water and converting to sulfuric acid.

Response: We agree that SO_2 in particular, and perhaps other gaseous compounds, can react with the collecting liquids used in the method to form materials (artifacts) that would not otherwise be solid or liquid or would not condense upon exiting the stack. We believe that when Method 202 is applied appropriately (i.e., with the N_2 purge as prescribed), the SO_2 artifact formation is reduced by as much as or more than 90 percent; however, we agree that further verification and refinement would be appropriate to verify the potential for artifact formation.

In response, we are undertaking laboratory studies in collaboration with several stakeholders to characterize the artifact formation and other uncertainties associated with conducting Method 202, and to identify procedures to be used in applying methods to minimize uncertainties. We are involving stakeholders representing industry and State and local agencies in the project design and results review. Stakeholders who have expressed interest in participating in these studies include the Electric Power Research Institute, companies associated with the National Environmental Development Association's Clean Air Project (NEDA/CAP), the Portland Cement Association, the Lime Manufacturing Association, the American Foundry Association, the National Aluminum Association, and several governmental organizations represented by National Association of Clean Air Agencies. Other parties may participate in the study as well.

By the end of 2007, we intend to have conducted a comprehensive laboratory study that examines the relationship between several critical condensable PM sampling and analysis parameters (e.g., SO_2 concentration, moisture concentration, sample duration, and water acidity) and the artifact formation associated with the measurements. One intended result of the project will be identifying possible modifications to Method 202 to minimize and quantify the uncertainties. We will publish the results of the laboratory study along with an assessment of other input and data from stakeholders on the EPA website and, to the extent possible, in a widely circulated peer review journal. Also, to the extent necessary, we intend to propose revisions to the method to incorporate improvements and to clarify application.

2. Conditional Test Methods 039 and 040

Comment: Several commenters cited as a deficiency that neither conditional test method 040 (CTM–040) for measuring filterable $PM_{2.5}$ nor the dilution sampling method (CTM–039) has been thoroughly validated through EPA Method 301. There were also comments that neither of the CTMs was published in the **Federal Register**.

Response: We agree with the comments that neither method has been subjected to adequate public notice and comment rulemaking. Taking that step will facilitate application of the appropriate methods for implementing the SIPs. On the other hand, there are a number of levels of validation already achieved for one or more of these methods that will determine what, if any, additional validation work will be necessary. For example, while we could seek resources to evaluate dilution sampling technology, including CTM–039, and to request public involvement in the project planning, conduct, and review with the possibility of a **Federal Register** proposal, our preference would be to incorporate by reference an approved voluntary consensus test method (e.g., ASTM standard).

We believe that a dilution sampling method for measuring direct $PM_{2.5}$ eliminates essentially all artifact formation and provides the most accurate emissions quantification. To the extent that we need to and can secure resources and stakeholder interest, we plan to perform additional validation testing of CTM–039 or other dilution sampling technologies to characterize the precision of this approach. In conjunction with our validation efforts, we intend to continue participation in the ASTM D22 committee to develop and publish a dilution sampling method and encourage other volunteers on that committee to approve the consensus based dilution sampling method. We believe that this work is nearly complete. As outlined above, we are already undertaking laboratory studies to assess the method and to identify possible modifications to reduce formation of these artifacts. Preliminary laboratory evaluations conducted by EPA and by Environment Canada[47] indicate that additional artifact reductions of 60 to 90 percent may be achieved with other minor modifications to Method 202. These preliminary findings indicate that Method 202 is essentially a viable method that these proposed laboratory studies will serve to enhance. Within 18 months we intend to propose, if necessary, modifications to Method 202 or similar methodologies suitable for measuring condensable $PM_{2.5}$.

As for CTM–040, we believe that further validation of this method is unwarranted since the technology and procedures are based upon the same as evaluated for promulgated Method 201A. Method 201A has undergone public review and comment (55 FR 14246, April 17, 1990). Also, as noted earlier, we have already begun laboratory and data evaluation work the possible result of which would be a revised Method 202 to be proposed in the **Federal Register** to include improvements indicated by the evaluation. At that same time, we may propose CTM–040 to be used in combination with Method 202 for measuring direct $PM_{2.5}$ with additional guidance on appropriate approaches to testing for direct $PM_{2.5}$ emissions from various types of control measures (e.g., electrostatic precipitator and flue gas desulphurization combinations).

3. Role of Condensable PM Emissions in Defining RACT

Comment: Commenters indicated that States must reassess and revise emissions limits if the States adopt methods for measuring direct $PM_{2.5}$ including condensable PM where not required previously. Commenters noted that most existing PM emissions limits are not reflective of data collected with

[47] ''Optimized Method 202 Sampling Train to Minimize the Biases Associated with Method 202 Measurement of Condensable Particulate Matter Emissions,'' John Richards, Tom Holder, and David Goshaw, Air Control Techniques, P.C.; Air & Waste Management Association, Hazardous Waste Combustion Specialty Conference AWM, November 2–3, 2005, St. Louis, MO.

methods that measure condensable or filterable $PM_{2.5}$ and, therefore, not enforceable using a new or different test method.

Response: We agree that coordinating the test method with the pollutant defined by the emissions limit is critical to an effective regulation. In the case of direct $PM_{2.5}$ regulations, the methods for measuring filterable and condensable PM provide data that are significantly different than do methods often used in implementing many current regulations (i.e., filterable plus condensable $PM_{2.5}$ versus filterable PM only). The existing PM emissions regulations implementing many current SIPs have focused almost exclusively on filterable PM at stack conditions or other elevated temperatures (e.g., 250 °F) with little or no measurement of condensable PM, let alone filterable $PM_{2.5}$. These deficiencies exist in spite of the Agency's policies and guidance presented in documents such as the 1987 PM_{10} SIP Development Guideline [48] and the General Preamble for the Implementation of Title 1 of the Clean Air Act Amendments of 1990 [49] issued in 1992. These documents set forth Agency policy stating that direct PM_{10} and direct $PM_{2.5}$ emissions include both filterable and condensable particulate matter. The policies are reinforced by a 2005 directive from the CAA Advisory Committee.[50]

More to the point, the use of test methods that quantify only filterable PM would limit the capability of any assessment of control measures available for developing cost effective strategies to achieve attainment of the $PM_{2.5}$ NAAQS. Examples include an attainment demonstration that includes control methodologies for PM precursors which are likely to result in a significant decrease in the emissions of direct $PM_{2.5}$ (for example, alkaline scrubbers to reduce SO_2 emissions) and incorporate these direct $PM_{2.5}$ emissions reductions in their attainment demonstration or allow for the use of these reductions as credits for other programs.

Some States may decide to measure and control condensable PM emissions prior to the end of the transition period. To the extent that a State has the supporting technical information and test methods, the State may also assess the capabilities of current control technologies, possible modifications to such technologies, or new technologies as appropriate relative to control of condensable $PM_{2.5}$ emissions in developing effective control strategies and regulations. As an example, a specific approach for controlling condensable PM could be a change in control device operating temperature to achieve necessary emissions reductions. We also note that it is important that implementation of any new or revised rules and test methods should be prospective and clearly differentiated from existing regulations to avoid confusion over status of compliance relative to existing PM emissions limits.

4. Sufficiency of Current Baselines Relative to Direct $PM_{2.5}$ for Regulatory Development

Comment: Many commenters indicated that the currently available baselines for direct $PM_{2.5}$ emissions are not sufficient for States to develop effective emissions control regulations. One commenter claimed that States will need additional information regarding how to arrive at enforceable $PM_{2.5}$ emissions limitations through application of correlations to existing PM_{10} emissions limitations.

Response: We agree that State inventories accounting for direct $PM_{2.5}$ emissions are important to the NAAQS implementation decision-making process. For example, the current national emissions inventories have characterized the contribution of the condensable PM emissions to range from 40 to 80 percent of the direct $PM_{2.5}$ emissions particularly from combustion source categories. We also agree in many cases, the emissions baselines are not sufficiently representative of significant direct $PM_{2.5}$ contributors to allow States to develop effective and enforceable emissions limitations for sources that may require control of direct filterable or condensable $PM_{2.5}$ emissions in order for States to come into attainment with the $PM_{2.5}$ NAAQS.

We note that States are already required under the consolidated emissions reporting rule (CERR) to report direct $PM_{2.5}$ emissions, including condensable PM, in each inventory revision. That means that inventories and associated baselines must address sources and contributions of direct $PM_{2.5}$ emissions, both filterable and condensable PM, from individual sources and groups of sources as well as for future year projected emissions. These data are important for the purposes of calculating emissions reductions and demonstrating that such reductions are attributable to the control measures being implemented.

In taking the process to the next step, we contend that many current baselines established using the available direct filterable and condensable $PM_{2.5}$ national industry average emissions factors (e.g., those found in AP–42 and WebFIRE, *http://www.epa.gov/ttn/chief/efpac/index.html*) often are of quality insufficient to establish effective source-specific emissions limits. First, national industry average emissions factors are subject to significant uncertainties as they usually represent data from a very limited number of example facilities in a category and for a very limited number of operating conditions. Second, the available emissions factors databases may not include direct $PM_{2.5}$ emissions data for specific source types that appear in some State and local inventories.

In short, we believe that States should rely on directly measured emissions data in developing source category or pollutant-specific emissions limits for regulations. This approach is preferable to the use of these national industry average emissions factors such as those found in AP–42. If there are no directly measured emissions data available from the subject sources, national average emissions factors should be used only with appropriate and significant adjustments for uncertainty. Based on our initial study [51] of the uncertainties associated with national average emissions factors when applied to site-specific or rule-development activities, we would expect multipliers of 0.1 to 3.3 for an A-rated national average filterable and condensable direct $PM_{2.5}$ emissions factors. The level of a particular multiplier would depend on how representative of the source category the applicable emissions factor is, the quantity of data supporting that emissions factor, and the specific application. Determining what adjustment may apply for a particular application requires detailed knowledge of the emissions control variability, the expected range of operational and process variability, and the statistical uncertainty in the measured emissions data. While more general adjustments to emissions factors are possible for these purposes, we believe that the better approach is to improve and update the emissions factors used in the database for a particular area with measured

[48] U.S. Environmental Protection Agency. PM–10 SIP Development Guideline. Office of Air Quality Planning and Standards, Research Triangle Park, NC. EPA Publication No. EPA–450/2–86–001. June 1987.

[49] The General Preamble is available online at *http://www.epa.gov/ttn/oarpg/t1pfpr.html.*

[50] Clean Air Act Advisory Committee, Recommendations to the Clean Air Act Advisory Committee—Phase I and Next Steps, Air Quality Management Work Group, Environmental Protection Agency, *http://www.epa.gov/air/caaac/pdfs/report1-17-05.pdf*, January 2005.

[51] Option Paper 4—Providing Guidance Regarding The Use Of Emissions Factors For Purposes Other Than Emissions Inventories, September 2005, *http://www.epa.gov/ttn/chief/efpac/projects.html.*

direct $PM_{2.5}$ emissions data. For these reasons and to allow time for data collection and analysis, we have determined the need for a period of transition for States in developing direct $PM_{2.5}$ emissions reduction strategies.

5. Transition Period

Comment: Some commenters suggested that EPA should allow States to base their initial 2008 SIPs on NO_X, SO_2, and filterable PM or PM_{10} (as a surrogate for filterable $PM_{2.5}$) rather than require State and local agencies to develop direct $PM_{2.5}$ emissions regulations immediately. Commenters suggested that EPA provide a transition period for sources to adopt SIPs that address direct $PM_{2.5}$ and to apply the appropriate test methods. The commenters proposed that during this transition period, a source should be able to continue to use Method 5, Method 17, or whatever method was used to set the underlying limit contained in the source's title V operating permit. Commenters believe that such a transition plan must provide additional time to collect data related to condensable PM emissions. Commenters believe that this additional time is necessary because it is unrealistic to develop SIP revisions addressing condensable emissions by April 2008. Other commenters suggested that source emissions inventories used for regulatory decision-making and identifying regulatory control measures must be based on accurate measurements.

Response: As outlined above, we agree that a transition period should be allowed to allow time to resolve and adopt appropriate testing procedures for condensable PM emissions, to collect total (filterable and condensable) $PM_{2.5}$ emissions data that are more representative of the sources in their areas, and develop effective regulations for control of direct $PM_{2.5}$, including condensable PM.

6. Data Collection for Regulatory Development

Comment: Several commenters recommended that EPA should be responsible for developing data of emissions from common sources of direct $PM_{2.5}$.

Response: We disagree with the commenters' recommendation that EPA should be primarily or solely responsible for developing baseline data on common sources of direct $PM_{2.5}$ emissions. Commenters are suggesting that we should collect data representative of direct $PM_{2.5}$ emissions from source categories potentially subject to regulation of direct $PM_{2.5}$ emissions. Furthermore, they suggest that we expand or improve the current compilation of national industry average emissions factors such as found in AP–42 and WebFIRE (*http://www.epa.gov/ttn/chief/efpac/index.html*). Given the limited extent to which national industry average emissions factors are suitable for developing State or local regulations that set limits on direct $PM_{2.5}$ emissions, we believe that it is inherent that States instead have primary responsibility for reviewing and applying measured emissions data collected from their sources in enhancing their current baselines. In some cases, this will mean that States and other stakeholders will need to conduct more focused direct $PM_{2.5}$ emissions data collection and improve relevant emissions factors.

This approach is appropriate for several reasons. First, we believe that stakeholders other than EPA are better equipped to identify specific data needs and that they have the means to collect the data. Second, we believe we are better positioned to provide guidance on test planning, data collection, and emissions factors calculations with a less direct role in data collection and evaluation. Third, we believe that States in need of additional information can also benefit from experience of other States with similar source types and who are developing regulations to implement the NAAQS including the control of condensable PM. See also the discussion in section II.L.2.c.1 above on the currently active collaborative study to assess direct $PM_{2.5}$ emissions measurement technologies and to collect updated direct $PM_{2.5}$ emissions data.

7. Developing Effective Regulations for Direct $PM_{2.5}$, Including Condensable PM, Emissions

Most current PM regulations focus on the control and measurement of filterable PM emissions and do not account for condensable PM emissions. At issue are assessing and accounting for the differences in methodology and applicable limits when changing to a program designed to achieve reductions in $PM_{2.5}$ emissions, including condensable PM.

Comment: A number of respondents commented that EPA needs to promulgate a $PM_{2.5}$ test method and adopt regulatory language that determines the $PM_{2.5}$ limits based on that promulgated $PM_{2.5}$ test method as soon as possible. Other commenters suggested that EPA and States have no choice but to revise the underlying standard by adopting new monitoring requirements through a notice and comment rulemaking. Further, these commenters indicate that it is essential that EPA require that no change in a test method or in methods of monitoring for determining compliance until such time as EPA or the permitting agency have undertaken a notice and comment process to determine how the emissions limitations must be revised. A number of commenters cited specific components necessary for effective regulations.

Response: We agree that notice and comment rulemaking is appropriate for establishing effective regulations. As noted above, we are already undertaking a study of the available test methods to determine the need for regulatory revisions. We also agree that new regulations limiting direct $PM_{2.5}$ emissions must include effective emissions limitations to the extent that a State must reduce sources of direct $PM_{2.5}$. How a State determines to take such regulatory action depends on the State's implementation plan. Regarding the specific components necessary for effective regulations, see section O below on enforcement and compliance issues.

M. Improving Source Monitoring

a. Background

In the November 1, 2005 proposal, we discussed a number of actions the EPA would undertake to improve the effectiveness of existing and new regulations with improved source monitoring provisions. Specifically, we repeated a plan outlined on January 22, 2004 (69 FR 3202; a **Federal Register** notice describing requirements for monitoring in operating permits), that includes a four-part strategy for improving monitoring of emissions at the source where necessary through rulemaking. One element of that plan is for EPA to develop guidance on how States can reduce $PM_{2.5}$ emissions by improving source monitoring related to $PM_{2.5}$ emissions limits. We noted that we expect to describe in such guidance methods of improving monitoring frequency or adopting more appropriate monitoring for States to consider in developing their $PM_{2.5}$ SIPs and to illustrate the amount of credit that States could receive in $PM_{2.5}$ SIPs for adopting such improved monitoring. We suggested that States with areas where additional reductions are needed to help the area achieve compliance with the NAAQS could implement improved monitoring measures to obtain additional emissions reductions. We put forward that State agencies could receive SIP credits as a result of enforceable improved monitoring or

voluntary emissions monitoring programs meeting EPA voluntary program policies.

Specific examples of improved monitoring we outlined included: (1) Conducting the currently required monitoring more frequently (i.e., increased monitoring frequency), (2) changing the monitoring technique to a parameter more closely related to control of direct or precursor $PM_{2.5}$ emissions (i.e., a correlated parametric monitoring technique), (3) changing the technique to more measurement of direct $PM_{2.5}$ emissions and $PM_{2.5}$ precursors, or (4) a combination of these improvements. These types of monitoring improvements could be conducted for both controlled and uncontrolled emissions units. The improved monitoring control measure would require facilities to pay more attention to the operation of add-on air pollution control devices, work practices, and other control measure activities. The additional attention will reduce periods during which control devices and other control measures do not operate as intended or required. The result would be increased emissions reductions from implementing existing and new rules.

We discussed a range of currently applied and new monitoring technologies. We addressed concerns we have about the limitations of the widespread use of visual emissions (VE) monitoring techniques, such as visible emissions checks, to show compliance with PM emissions limits. We noted particular concerns about VE approaches, even with frequent application, having the ability to verify compliance when the margin of compliance is small or the ability to detect relatively significant changes in emissions control performance. The other concern we noted about the use of VE tools is the limited frequency at which they are conducted. We cited studies on the availability of continuous instrumental methods for monitoring opacity and operational parameters closely related to PM control levels including the development of repeatable correlations between parameter levels and PM emissions. We noted that PM continuous emissions monitoring systems (PM CEMS) technology provides the opportunity to quantify PM emissions levels (concentration or emissions rates). These additional data provide the source owner/operator with a level of information that can be useful for understanding and operating the process and the control measures in ways to minimize emissions, improve operating efficiencies, and reduce enforcement liabilities. Furthermore, we noted that this technology will provide the State with quantitative information on PM emissions which will help improve the inventories and to implement effective control strategies to meet the NAAQS.

We also discussed at some length what we believe constitutes improved monitoring and the potential for monitoring-related emissions reductions. We discussed a study of how these emissions reductions would be achieved by increasing the monitoring frequency or improving the monitoring of an add-on air pollution control device or other process activity above the level currently required in existing rules. The increased frequency or improved technique would allow owners or operators to achieve greater emissions reductions by identifying and responding more quickly to periods of ineffective control measure operation. States could use an improved monitoring control measure in regulations or through other means to reduce emissions levels and receive credits towards attainment. Specifically, we cited materials that indicate that source owners and operators who increase monitoring frequency could achieve emissions reductions up to 13 percent and those who improve the monitoring technique could achieve emissions reductions up to 15 percent. States with nonattainment areas in need of additional reductions to achieve compliance with the NAAQS could implement an improved monitoring measure and develop additional emissions reductions credits. We outlined several specific examples.

In order to inform our improved monitoring guidance development efforts, we used the 2005 proposal to solicit specific comments on (1) how potentially inadequate source monitoring in certain SIPs could be improved; (2) how improved $PM_{2.5}$ monitoring relates to title V monitoring; (3) whether instrumental techniques are more appropriate than visual emissions (VE) techniques for monitoring compliance with PM emissions limits; and (4) a basis for determining whether improved monitoring would be effective and under what conditions should be required. We also requested comment on the feasibility of monitoring of co-pollutant control measures and requested examples of improved monitoring for any applications.

b. Final Rule

We maintain that improved monitoring is critical to implementing the $PM_{2.5}$ direct and precursor emissions reductions programs. We also believe that improving monitoring both in terms of increasing data collection and analysis frequency and in measuring the pollutant of interest more directly will accomplish several important and advantageous outcomes. First, improved monitoring will improve verification of compliance and assurance of the intended emissions reductions. Second, improved monitoring can provide additional emissions reductions through quicker detection and correction of control measure problems. Third, improved monitoring can improve operating efficiencies that often result in cost savings to the facility exceeding the cost of the monitoring. We will continue to evaluate the effects of improved monitoring on emissions reductions and ways to quantify the benefits associated with improved monitoring.

We intend to move forward with developing and providing additional technical and informational materials regarding technologies constituting improved monitoring and for developing regulations with improved monitoring. These materials may also include guidance and tools for establishing emissions reductions credits and the economic benefits associated with improved monitoring. As noted in section L above, we also reaffirm our policy that effective regulations must include certain elements that define applicable emissions limitations, the testing and monitoring requirements, and compliance, reporting, and corrective action obligations.

c. Comments and Responses

We expected to receive practical advice concerning improved $PM_{2.5}$ source emissions monitoring methods and field-tested examples. Instead, commenters focused on (1) critiquing PM CEMS technology (2) insisting that improving monitoring changes stringency of existing rules and requires rulemaking, and (3) critiquing the theoretical study linking emissions reductions with improved monitoring.

1. Currently Available PM CEMS for Monitoring Direct $PM_{2.5}$ Emissions

Comment: Commenters noted that because currently available PM CEMS measure filterable PM at stack conditions or at other elevated temperatures, the instruments do not measure the condensable portion of $PM_{2.5}$.

Response: We agree with this comment relative to PM CEMS in use to date and the ability to detect condensable PM. PM CEMS as applied today can be calibrated to measure filterable $PM_{2.5}$ emissions with very good sensitivity and repeatability. Note

that we are aware of a number of PM CEMS vendors developing devices relying on much the same technology but modified to measure condensable PM. Further, we are aware of at least one manufacturer offering a PM CEMS applicable to stationary sources that also complies with ASTM requirements for mobile source emissions monitoring. We also believe that monitoring for filterable $PM_{2.5}$ will be as important in some cases as monitoring for condensable PM and that PM CEMS in use today are markedly better at monitoring PM emissions than other frequently used monitoring approaches.

We realize that PM CEMS represent just one of a range of monitoring options that constitute improvements over the current monitoring. For instance, we believe that improved monitoring would include replacing current periodic VE measurements or daily recording of pressure drop of fabric filters with continuous bag leak detectors. We know of projects (e.g., ASTM committee work) for continuing the development of optical, as well as electromagnetic, monitoring tools to increase sensitivity and cost-effectiveness. Such monitoring would increase monitoring frequency and would yield data much more closely related to and more sensitive to control device operation than most currently applied monitoring. To the extent that condensable PM control is critical in implementing a regulation, we believe that monitoring must address that need. We will continue to collect and also provide information on source monitoring approaches that are improvements over current methods in both frequency and representativeness relative to implementing $PM_{2.5}$ emissions control strategies.

2. Status of Guidance Relative to Regulations

Comment: A significant majority of commenters suggested that improving monitoring in an existing regulation increases its stringency and requires notice and comment rulemaking, not guidance. Just one commenter suggested guidance could be developed and used.

Response: There are two aspects to the comments on this issue. One is whether improved monitoring would change source operations. We agree with the commenters that increasing the frequency of data collection or providing data more directly related to the pollutant of concern with improved monitoring could result in changes in how a facility is operated relative to compliance. We disagree with commenters that such changes in process operation resulting from improved monitoring constitute an increase in a regulation's stringency with respect to compliance. First, as mentioned in the preamble to the Credible Evidence rule (62 FR 8326, February 24, 1997), an emissions standard's required stringency is unaffected by the frequency of monitoring given no decrease in averaging time or emissions limitation. Secondly, data from improved monitoring will provide a facility operator better information on control measure performance more quickly and allow for reducing the duration and the number of periods that may lead to compliance problems. Reducing the duration of excess emissions periods, for example, with improved monitoring is not an increase in regulatory stringency but a decrease in enforcement liability.

The second aspect to the comment is questioning whether we can issue technical information about improved monitoring as guidance without applying it to a **Federal Register** notice and comment process. We disagree with commenters who believe that our developing and disseminating technical resource information is limited to notice and comment rulemaking. We note that making technical and other information materials available to the public, states, and industry is an important Agency function. There are many examples of the Agency dispensing such information including the Monitoring Knowledge Base (*http://cfpub.epa.gov/mkb/*) that provides just such information on improved monitoring. On the other hand, we agree with commenters that any significant change to an existing regulation, including the addition of new monitoring requirements, would be subject to notice and comment rulemaking. To the extent that States determine the need for changing existing or developing new regulations, public notice and comment rulemaking is appropriate. Our role in developing technical resources and information informing the states in developing those revised or new regulations does not require, nor should be subject to the rulemaking process. In that light, we recognize the value in obtaining and responding to public comments and suggestions on informative technical materials. Further, we believe rulemaking is not necessarily required for source owners or operators who volunteer to participate in an optional improved monitoring program, such as the one mentioned in the proposal. That program seeks to provide SIP credits to States where source owners or operators agree to improve their PM monitoring approaches. We plan on continuing to prepare and offer non-regulatory incentives for source owners and operators who volunteer to improve existing monitoring.

3. Study of Improved Monitoring-Induced Emissions Reductions

Comment: Commenters recommended that the proposal's theoretical study showing PM emissions reductions from the use of improved monitoring needs to be validated with field data.

Response: We agree with commenters that one should base any costs and benefits findings as well as validating the approach on available data. To the extent that this applies to assessing the benefits of emissions reductions achieved through improved monitoring, we requested that commenters provide data or leads to other information or to other alternatives that show how improved monitoring yields emissions reductions and ways to quantify possible PM credits for SIPs. In fact, we are disappointed that commenters failed to provide these data or examples of other approaches. As resources allow, we will investigate opportunities for field validation of the theoretical study, as well as other means to offer incentives for use of improved monitoring.

N. Guidance Specific to Tribes

a. Background

The proposal set forth guidance for Tribes regarding various aspects of air quality management, and this guidance remains largely the same as described in the section below.

b. Final Rule

The 1998 Tribal Authority Rule (TAR) (40 CFR part 49), which implements section 301(d) of the CAA, gives Tribes the option of developing tribal implementation plans (TIPs). Specifically, the TAR provides for the Tribes to be treated in the same manner as a State in implementing sections of the CAA. However, Tribes are not required to develop implementation plans. The EPA determined in the TAR that it was inappropriate to treat Tribes in a manner similar to a State with regard to specific plan submittal and implementation deadlines for NAAQS-related requirements, including, but not limited to, such deadlines in CAA sections 110(a)(1), 172(a)(2), 182, 187, and 191. (Add footnote) See 40 CFR 49.4(a). In addition, EPA determined it was not appropriate to treat tribes similarly to states with respect to provisions of the CAA requiring as a condition of program approval the demonstration of criminal enforcement

authority or providing for the delegation of such criminal enforcement authority. See 40 CFR 49.4(g). To the extent a tribe is precluded from asserting criminal enforcement authority, the Federal government will exercise primary criminal enforcement responsibility. See 40 CFR 49.8. In such circumstances, tribes seeking approval for CAA programs provide potential investigative leads to an appropriate federal enforcement agency. (end footnote)

If a Tribe elects to do a TIP, we will work with the Tribe to develop an appropriate schedule which meets the needs of the Tribe, and which does not interfere with the attainment of the NAAQS in other jurisdictions. The Tribe developing a TIP can work with the EPA Regional Office on the appropriateness of addressing RFP and other substantive SIP requirements that may or may not be appropriate for the Tribe's situation.

The TAR indicates that EPA is ultimately responsible for implementing CAA programs in Indian country, as necessary and appropriate, if Tribes choose not to implement those provisions. For example, an unhealthy air quality situation in Indian country may require EPA to develop a FIP to reduce emissions from sources on the reservation. In such a situation, EPA, in consultation with the Tribe and in consideration of their needs, would work to ensure that the NAAQS are met as expeditiously as practicable. Likewise, if we determine that sources in Indian country could interfere with a larger nonattainment area meeting the NAAQS by its attainment date, we would develop a FIP for those sources in consultation with the Tribe, as necessary or appropriate.

The TAR also provides flexibility for the Tribe in the preparation of a TIP to address the NAAQS. If a Tribe elects to develop a TIP, the TAR offers flexibility to Tribes to identify and implement on a Tribe-by-Tribe, case-by-case basis only those CAA programs or program elements needed to address their specific air quality problems. In the proposed Tribal rule, we described this flexible implementation approach as a modular approach. Each Tribe may evaluate the particular activities, including potential sources of air pollution within the exterior boundaries of its reservation (or within non-reservation areas for which it has demonstrated jurisdiction), which cause or contribute to its air pollution problem. A Tribe may adopt measures for controlling those sources of $PM_{2.5}$-related emissions, as long as the elements of the TIP are reasonably severable from the package of elements that can be included in a whole TIP. A TIP must include regulations designed to solve specific air quality problems for which the Tribe is seeking EPA approval, as well as a demonstration that the Tribal air agency has the authority from the Tribal government to develop and run their program, the capability to enforce their rules, and the resources to implement the program they adopt. In addition, the Tribe must receive an eligibility determination from EPA to be treated in the same manner as a State and to receive authorization from EPA to run a CAA program.

The EPA would review and approve, where appropriate, these partial TIPs as one step of an overall air quality plan to attain the NAAQS. A Tribe may step in later to add other elements to the plan, or EPA may step in to fill gaps in the air quality plan as necessary or appropriate. In approving a TIP, we would evaluate whether the plan interferes with the overall air quality plan for an area when Tribal lands are part of a multi-jurisdictional area. Because many of the nonattainment areas will include multiple jurisdictions, and in some cases both Tribal and State jurisdictions, it is important for the Tribes and the States to work together to coordinate their planning efforts. States need to incorporate Tribal emissions in their base emission inventories if Indian country is part of an attainment or nonattainment area. Tribes and States need to coordinate their planning activities as appropriate to ensure that neither is adversely affecting attainment of the NAAQS in the area as a whole.

c. Comments and Responses

No public comments were received on this section.

O. Enforcement and Compliance

a. Background

The proposed rule included a discussion of the specific requirements that must be addressed in order for SIP regulations to be enforceable.

b. Final Rule

The final rule includes similar guidance on enforceable SIP regulations, with some additional discussion about specific elements that must be addressed regarding compliance testing and compliance monitoring. (Note that enforceable SIP regulations may address these key elements in different ways depending on the type of source category being regulated.)

In general, for a SIP regulation to be enforceable, it must clearly spell out which sources or source types are subject to its requirements and what its requirements (e.g., emission limits, work practices, etc.) are. The regulation also needs to specify the time frames within which these requirements must be met, and must definitively state recordkeeping and monitoring requirements appropriate to the type of sources being regulated. The recordkeeping and monitoring requirements must be sufficient to enable the State or EPA to determine whether the source is complying with the emission limit on a continuous basis. An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.

Complete and effective regulations that ensure compliance with an applicable emissions limit must include requirements for both performance testing of emissions and ongoing monitoring of the compliance performance of control measures. SIP regulations must include the following critical elements of regulatory compliance testing:

- Indicator(s) of compliance—the pollutant or pollutants of interest (e.g., filterable $PM_{2.5}$ plus condensable $PM_{2.5}$) and the applicable measurable units for expressing compliance (e.g., ng/J of heat input, lb/hr);
- Test method—reference to a specific EPA or other published set of sample collection and analytical procedures, equipment design and performance criteria, and the calculations providing data in units of the indicator of compliance (see section II.L. below for descriptions of available and potential improved test methods);
- Averaging time—the minimum length of each required test run and the requirement to average the results of the test runs (e.g., three runs) representing a specified period of time (e.g., 8 hours); and
- Frequency—the maximum time between conduct of emissions or performance tests (e.g., within 30 days of facility start-up and once each successive quarter, every 6-month period, yearly).

In order to be complete with regard to compliance monitoring provisions, SIP regulations must include the following critical elements:

- Indicator(s) of performance—the parameter or parameters measured or observed for demonstrating proper operation of the pollution control measures or compliance with the applicable emissions limitation or standard. Indicators of performance may include direct or predicted emissions measurements, process or control device (and capture system) operational

parametric values that correspond to compliance with efficiency or emissions limits, and recorded findings of verification of work practice activities, raw material or fuels pollutant content, or design characteristics. Indicators may be expressed as a single maximum or minimum value, a function of process variables (e.g., within a range of pressure drops), a particular operational or work practice status (e.g., a damper position, completion of a waste recovery task), raw material or fuel pollutant content, or an interdependency between two or more variables;

• Measurement technique—the means used to gather and record information of or about the indicators of performance. The components of the measurement technique include the detector type or analytical method, location and installation specifications, inspection procedures, and quality assurance and quality control measures. Examples of measurement approaches include continuous emissions monitoring systems, continuous opacity monitoring systems, continuous parametric monitoring systems, performance testing, vendor or laboratory analytical data, and manual inspections and data collection that include making records of process conditions, raw materials or fuel specifications, or work practices;

• Monitoring frequency—the number of times to obtain and record monitoring data over a specified time interval. Examples of monitoring frequencies include at least one data value every 15 minutes for continuous emissions or parametric monitoring systems, at least every 10 seconds for continuous opacity monitoring systems, upon receipt or application of raw materials or fuel to the process, and at least once per operating day (or week, month, etc.) for performance testing, work practice verification, or equipment design inspections; and

• Averaging time—the period over which to average and use data to verify compliance with the emissions limitation or standard or proper operation of the pollution control measure. Examples of averaging time include a 3-hour average in units of the emissions limitation, a 30-day rolling average emissions value, a daily average of a control device operational parametric range, periodic (e.g., monthly, annual) average of raw materials or fuel pollutant content, and an instantaneous alarm.

These regulatory elements are essential for effective implementation of the rules and clear and enforceable applicable requirements. We believe that approval of regulations implementing the SIPs must ensure that these critical elements are present and clearly defined to be approvable. We reiterate that the compliance obligations, including emissions limits and other applicable requirements, must be representative of and accountable to the assumptions used in the SIP demonstration. This accountability includes the ability to transfer the applicable regulatory requirements to an operating permit subject to EPA and public review.

Under the Title V regulations, sources have an obligation to include in their Title V permit applications all emissions for which the source is major and all emissions of regulated air pollutants. The definition of regulated air pollutant in 40 CFR 70.2 includes any pollutant for which a NAAQS has been promulgated, which would include both PM_{10} and $PM_{2.5}$. To date, some permitted entities have been using PM_{10} emissions as a surrogate for $PM_{2.5}$ emissions. Upon promulgation of this rule, EPA will no longer accept the use of PM_{10} as a surrogate for $PM_{2.5}$. Thus, sources will be required to include their $PM_{2.5}$ emissions in their Title V permit applications, in any corrections or supplements to these applications, and in applications submitted upon modification and renewal.[52] The degree of quantification of $PM_{2.5}$ emissions required will depend on the types of determinations that a permitting authority needs to address for a particular source, the requirements of title V, and the informational needs and requirements of the particular State in question. Sources must continue to describe their PM_{10} emissions in their applications as indicated above because the original PM_{10} NAAQS remains in effect.

c. Comments and Responses

Comment: One commenter disagreed with language in the preamble to the proposal regarding Title V permitting requirements and the requirement to include various emissions information in title V permit applications. As described in 40 CFR 70.5(c)(3)(i) and 71.5(c)(3)(i), sources are required to include in their permit applications all emissions for which the source is major and all emissions of regulated air pollutants. In the preamble to the proposal, the EPA stated that in the past some permitted entities have been using PM_{10} emissions as a surrogate for $PM_{2.5}$ emissions in permit applications, or in corrections or supplements to applications. The EPA stated that upon promulgation of this rule, the EPA will no longer accept the use of PM_{10} as a surrogate for $PM_{2.5}$.

The commenter disagreed with language in the proposal stating that sources would be required to detail or quantify $PM_{2.5}$ emissions in permit applications, or in corrections or supplements to applications. The commenter asserts that the inclusion of $PM_{2.5}$ emissions information is required in a Title V permit application only if there is an applicable requirement in existence for which the source's applicability is in question and cited to various examples from the memorandum entitled ''White Paper for Streamlined Development of Part 70 Permit Applications,'' from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, to Air Division Directors, Regions I–X, dated July 10, 1995.

Response: The commenter is concerned that as a result of this rule all applications (including initial, modification, and renewal applications) will need to include a quantification of $PM_{2.5}$ emissions, and that a State will request that every source supplement or correct any existing title V application in order to provide an estimation of $PM_{2.5}$ emissions at the source.

The EPA is not implying that this is the case. The degree of quantification of $PM_{2.5}$ emissions required in an application (including an initial, modification, or renewal application), or in a correction or supplement to an existing application, depends on the types of determinations that a permitting authority needs to address for a particular source, the requirements of title V, and the informational needs and requirements of the particular State in question. For example, if a source which emits $PM_{2.5}$ emissions has submitted a title V application, but a draft permit has not yet been issued, then the source is required to submit information relative to the quantification of its $PM_{2.5}$ emissions if such information is needed or requested and it has not previously submitted such information. See 40 CFR 70.5(b) and 71.5(b).

Circumstances necessitating the quantification of $PM_{2.5}$ emissions and the submittal of this information include: (1) Determining all of the pollutants for which a source is major; (2) determining whether an applicable requirement or program applies, e.g., determining the applicability of a SIP requirement or a PSD or nonattainment NSR program, etc.; or (3) determining what fees a source owes a permitting

[52] See 40 CFR 70.5(c)(3)(i), 70.5(b), and 70.7(a)(1)(i); 40 CFR 71.5(c)(3)(i), 71.5(b), and 71.7(a)(1)(i).

authority as a result of considering $PM_{2.5}$ emissions.

In all circumstances, however, a State may require that a source quantify its $PM_{2.5}$ emissions information in an application, supplement, or correction, even if it is not needed for the particular determination at issue. The State, for example, may choose to obtain this information for air quality planning purposes, developing emission inventories, or for other purposes related to its air quality management goals. Requesting such emissions information is an option for any title V permitting authority.

The ''White Paper for Streamlined Development of Part 70 Permit Applications,'' referenced by the commenter, was a confirmation of EPA policy with respect to the fact that the specificity of emissions quantification can vary significantly, depending on the circumstances of a particular source. It is also important to note that this guidance document is a statement regarding the range of discretion available to permitting authorities in implementing the emissions quantification requirement, not a restriction of that discretion to minimum practices. Thus, States can implement this guidance document at their option, either in part or in its entirety.

In summary, the purpose of the statements made in the preamble to the proposal was to notify sources that as of the promulgation of this final rule, the EPA will no longer accept the use of PM_{10} emissions information as a surrogate for $PM_{2.5}$ emissions information [53] given that both pollutants are regulated by a National Ambient Air Quality Standard and therefore are considered regulated air pollutants. See the definition of regulated air pollutant in 40 CFR 70.2 and 71.2.[54] The degree of quantification of $PM_{2.5}$ emissions now required in an application (including an initial, modification, or renewal application), or provided in a correction or supplement to an existing application, will depend on the types of determinations that a permitting authority needs to address for a particular source, the requirements of title V, and the informational needs and requirements of the particular State in question.

P. Emergency Episodes

a. Background

In the proposal, we noted that subpart H of 40 CFR part 51 specifies requirements for SIPs to address emergency air pollution episodes and for preventing air pollutant levels from reaching levels determined to cause significant harm to the health of persons. We noted that we anticipate proposing a separate rulemaking in the future to update portions of that rule. The preamble to the proposal

b. Final Rule

We have not yet proposed any rule revision related to emergency episodes.

c. Comments and Responses

We received no comments on this section of the proposal.

Q. Ambient Monitoring

a. Background

Ambient air quality monitoring for $PM_{2.5}$ plays an important role in identifying areas violating the NAAQS, control strategy development, and tracking progress to attainment. We indicated in the proposal that States are required to monitor $PM_{2.5}$ mass concentrations using Federal Reference Method devices to determine compliance with the NAAQS.[55] We did not propose any revisions to current ambient monitoring requirements listed in 40 CFR part 58. Currently, there are more than 1200 FRM monitors located across the country. States will need to maintain monitors in designated nonattainment areas in order to track progress toward attainment and ultimately determine whether the area has attained the $PM_{2.5}$ standards.

In addition to the FRM network, EPA and the States have also deployed more than 250 speciation monitoring sites around the country to sample for chemical composition of $PM_{2.5}$. The data provided from these speciation monitors are invaluable in identifying contributing source categories and developing control strategies to reach attainment. Source apportionment and other receptor modeling techniques rely on the detailed data on species, ions, and other compounds obtained from chemical analysis. Analyses of rural versus urban sites to identify which $PM_{2.5}$ components comprise the ''urban excess'' (urban minus rural levels) portion of $PM_{2.5}$ mass also rely on data from speciation monitors. The EPA encourages states to expand their data analysis efforts using the wealth of information provided from the speciation monitoring network.

b. Final Rule

There is no change from the proposal. We are not promulgating any additional monitoring requirements as part of this rulemaking. Revised monitoring regulations were issued in 2006 along with the revised PM NAAQS.

c. Comments and Responses

There were no comments on this section.

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action.'' Implementation of the $PM_{2.5}$ NAAQS is likely to have an annual effect on the economy of $100 million or more. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action. For clarity, we note that the estimated costs and benefits of implementing the 1997 $PM_{2.5}$ NAAQS are not created by this rule, because the Clean Air Act requires state implementation of the 1997 $PM_{2.5}$ standards (through state development of plans with enforceable requirements for sources) on a statutory timetable regardless of whether EPA issues this rule interpreting the statutory requirements. The rule reflects the statutory requirements.

As part of the ''Regulatory Impact Analysis for Particulate Matter National Ambient Air Quality Standards (September 2006),'' EPA prepared an assessment of the estimated costs and benefits associated with attaining the 1997 $PM_{2.5}$ NAAQS in 2015, incremental to currently promulgated federal and state programs including for example the Clean Air Interstate Rule, the Nonroad Diesel Rule, and other programs. This analysis is included as Appendix A of the report and is available in the docket for this action and on EPA's Web site at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/Appendix%20A—2015%20Analysis.pdf.* This illustrative

[53] For background information on issues surrounding implementation of the $PM_{2.5}$ NAAQS, see the EPA memo entitled ''Implementation of New Source Review Requirements in $PM_{2.5}$ Nonattainment Areas,'' from Stephen D. Page, Director, Office of Air Quality Planning and Standards, to Regional Air Directors, Regions I–X, dated April 5, 2005.

[54] For background information on regulated air pollutants, see the EPA memo entitled ''Definition of Regulated Air Pollutant for Purposes of Title V,'' from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, to Air Division Directors, Regions I–X, dated April 26, 1993.

[55] The $PM_{2.5}$ monitoring regulations are located at 40 CFR part 58.

analysis finds that the estimated monetized benefits of attaining the 1997 standards in 2015 are between $43 billion and $97 billion annually, and the estimated monetized costs are $6.7 billion annually. The RIA states: ''Note that because this analysis was intended to compare costs and benefits of attaining alternative standards by fixed dates, it did not attempt to identify for each designated $PM_{2.5}$ area measures that may be needed to meet subpart 1 Clean Air Act requirements, such as reasonably available measures and attainment as expeditiously as practicable. It is expected that additional costs and benefits will begin to accrue in earlier years as states comply with these requirements.'' (RIA, p. 1–4)

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* In a separate **Federal Register** notice published today, EPA is requesting comment on the information collection requirements of this rule. The information collection requirements are not enforceable until OMB approves them.

The data collected from the State or local air agency respondents will include the required SIP elements prescribed in CAA sections 110 and part D, subpart 1 of title I for Implementation plans and the requirements in this Implementation Rule (40 CFR 51.1000–51.1012). The $PM_{2.5}$ SIP will contain rules and other requirements designed to achieve the NAAQS by the deadlines established under the CAA, and it also contains a demonstration that the State's requirements will in fact result in attainment. The SIP must meet the requirements in subpart 1 to adopt RACM, RACT, and provide for RFP toward attainment for the period prior to the area's attainment date.

The Agency anticipates additional administrative burden during the 3 year period of the ICR for State governments and the Agency of 630,000 hours and 69,300 hours, respectively. Fifty percent of the hours are expended in the first year with the remainder evenly divided between the second and third years of the ICR period. Tribes are not required to conduct attainment demonstrations or submit the RFP, RACT, or RACM requirements.

The present value of the total additional costs for State government respondents is estimated at $33.4 million for the 3 year period. On an equivalent annual basis that is $12.7 million per year during the 3 year period of the ICR. The present value of the Agency administrative cost burden is estimated at $3.7 million dollars for the 3 year period. This is equivalent to an equal annual stream of costs of $1.4 million per year during the three year period. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this final action on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities and it is not necessary to prepare a regulatory flexibility analysis in conjunction with this final rule. The final rule governing SIPs will not directly impose any requirements on small entities. Rather, this rule interprets the obligations established in the CAA for States to submit implementation plans in order to attain the $PM_{2.5}$ NAAQS.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, EPA is required by section 205 of the UMRA to identify and consider a reasonable number of regulatory alternatives, and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

This rule contains no Federal mandate that may result in expenditures

of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any 1 year. The estimated administrative burden hours and costs associated with implementing the $PM_{2.5}$ NAAQS are estimated in the ICR for this rule. The estimated costs presented there for States totals $33.4 million for a three-year period. Thus, this rule is not subject to the requirements of section 202 and 205 of the UMRA. The EPA consulted with governmental entities affected by this rule and has determined that this rule contains no regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments.

The CAA imposes the obligation for States to submit SIPs to implement the $PM_{2.5}$ NAAQS. In this rule, EPA is merely providing an interpretation of those requirements. However, even if this rule did establish an independent requirement for States to submit SIPs, it is questionable whether a requirement to submit a SIP revision would constitute a Federal mandate in any case. The obligation for a State to submit a SIP that arises out of section 110 and section 172 (part D) of the CAA is not legally enforceable by a court of law, and at most is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(9a)(I) of UMRA (2 U.S.C. 658(a)(I)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(a)(i)(I) of UMRA (2 U.S.C. 658(5)(a)(i)(I)).

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications.'' ''Policies that have Federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

At the time of proposal, EPA concluded that the proposed rule would not have any federalism implications. The EPA stated that the proposed rule would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The CAA establishes the scheme whereby States take the lead in developing plans to meet the NAAQS. This rule clarifies the statutory obligations of States in implementing the $PM_{2.5}$ NAAQS. However, EPA recognized that States would have a substantial interest in this rule and any corresponding revisions to associated SIP requirements.

Therefore, in the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA held a number of calls with representatives of State and local air pollution control agencies and hosted a public hearing in Washington, DC in November 2005. The EPA considered the comments from State and local governments in developing the final rule.

EPA concludes that this final rule does not have federalism implications, for the reasons proposed. The final rule will not modify the relationship of the States and EPA for purposes of developing programs to implement the NAAQS. As noted above in section D on UMRA, this rule does not impose significant costs on State and local governments. (EPA estimates the costs to States to implement the $PM_{2.5}$ NAAQS to be $33.4 million.) Thus, Executive Order 13132 does not apply to this rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.'' This final rule does not have ''Tribal implications'' as defined in Executive Order 13175. This rule concerns the requirements for State and tribal implementation plans for attaining the $PM_{2.5}$ air quality standards. The CAA provides for States to develop plans to regulate emissions of air pollutants within their jurisdictions. The Tribal Air Rule (TAR) under the CAA gives Tribes the opportunity to develop and implement CAA programs such as programs to attain and maintain the $PM_{2.5}$ NAAQS, but it leaves to the discretion of the Tribe the decision of whether to develop these programs and which programs, or appropriate elements of a program, they will adopt.

Although Executive Order 13175 does not apply to this rule, EPA did reach out to Tribal leaders and environmental staff in developing this rule. From 2001–2004, the EPA supported a National Designations Workgroup to provide a forum for tribal professionals to give input to the designations process. In 2006, EPA supported a national ''Tribal Air call'' which provides an open forum for all Tribes to voice concerns to EPA about the NAAQS implementation process, including the $PM_{2.5}$ NAAQS. In these meetings, EPA briefed call participants and Tribal environmental professionals gave input as the rule was under development. Furthermore, in December 2005, EPA sent individualized letters to all federally recognized Tribes about the proposal to give Tribal leaders the opportunity for consultation.

This final rule does not have Tribal implications as defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes, since no Tribe has implemented a CAA program to attain the $PM_{2.5}$ NAAQS at this time. The EPA notes that even if a Tribe were implementing such a plan at this time, while the rule might have Tribal implications with respect to that Tribe, it would not impose substantial direct costs upon it, nor would it preempt Tribal law.

Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the Federal government and Indian Tribes. The CAA and the TAR establish the relationship of the Federal government and Tribes in developing plans to attain the NAAQS, and this rule does nothing to modify that relationship. As this rule does not have Tribal implications, Executive Order 13175 does not apply.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

EO 13045, ''Protection of Children from Environmental Health and Safety Risks,'' (62 FR 19885, April 23, 1997) applies to any rule that (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This final

rule is subject to EO 13045 because it is economically significant as defined in EO 12866, and we believe that the environmental health risk addressed by this action may have a disproportionate effect on children. This rule implements a previously promulgated health-based Federal standard—the $PM_{2.5}$ NAAQS [56]. The NAAQS constitute uniform, national standards for PM pollution; these standards are designed to protect public health with an adequate margin of safety, as required by CAA section 109. However, the protection offered by these standards may be especially important for children because children, along with other sensitive population subgroups such as the elderly and people with existing heart or lung disease, are potentially susceptible to health effects resulting from PM exposure. Because children are considered a potentially susceptible population, we have carefully evaluated the environmental health effects of exposure to PM pollution among children. These effects and the size of the population affected are summarized in section 9.2.4 of the Criteria Document and section 3.5 of the Staff Paper.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This final rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions That Significantly Affect Energy Supply, Distribution, or Use,'' (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This rule is not a ''significant energy action,'' because it does not establish requirements that directly affect the general public and the public and private sectors, but, rather, interprets the statutory requirements that apply to States in preparing their SIPs. The SIPs themselves will likely establish requirements that directly affect the general public, and the public and private sectors.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This final rulemaking does not involve technical standards. Therefore, EPA is not considering the use of any VCS. The EPA will encourage the States and Tribes to consider the use of such standards, where appropriate, in the development of their implementation plans.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

EO 12898 (59 FR 7629 (Feb. 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the United States.

The EPA has determined that the final rule should not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. The health and environmental risks associated with fine particles were considered in the establishment of the $PM_{2.5}$ NAAQS. The level is designed to be protective with an adequate margin of safety. This final rule provides a framework for improving environmental quality and reducing health risks for areas that may be designated nonattainment.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing the rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective June 25, 2007.

L. Petitions for Judicial Review

Under section 307(b)(1) of the Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by June 25, 2007. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. See Act section 307(b)(2).

M. Judicial Review

Under sections 307(d)(1)(E) and 307(d)(1)(V) of the CAA, the Administrator determines that this action is subject to the provisions of section 307(d). Section 307(d)(1)(V) provides that the provisions of section 307(d) apply to ''such other actions as the Administrator may determine.'' While the Administrator did not make this determination earlier, the Administrator believes that all of the procedural requirements, e.g., docketing, hearing and comment periods, of section 307(d) have been complied with during the course of this rulemaking.

IV. Statutory Authority

The statutory authority for this action is provided by 42 U.S.C. 7401, 7408, 7410, 7501–7509a, and 7601(a)(1). This notice is also subject to 307(d) of the CAA (42 U.S.C. 7407(d)).

List of Subjects in 40 CFR Part 51

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Sulfur oxides, Transportation, Volatile organic compound.

Dated: March 29, 2007.

Stephen L. Johnson,

Administrator.

■ For the reasons set out in the preamble, title 40, chapter I of the Code

[56] *See* 62 FR 38652–38760, National Ambient Air Quality Standards for Particulate Matter, Final Rule; also 40 CFR part 50.

of Federal Regulations is amended as follows:

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

■ 2. A new Subpart Z is added to read as follows:

Subpart Z—Provisions for Implementation of $PM_{2.5}$ National Ambient Air Quality Standards

Sec.

§ 51.1000 Definitions.

The following definitions apply for purposes of this subpart. Any term not defined herein shall have the meaning as defined in 40 CFR 51.100.

Act means the Clean Air Act as codified at 42 U.S.C. 7401–7671q. (2003).

Attainment date means the date by which an area, under an approved State implementation plan, is required to attain the $PM_{2.5}$ NAAQS (based on the average of three consecutive years of ambient air quality data).

Baseline year inventory for the RFP plan is the emissions inventory for the year also used as the base year for the attainment demonstration.

Benchmark RFP plan means the reasonable further progress plan that requires generally linear emission reductions in pollutants from the baseline emissions year through the milestone inventory year.

Date of designation means the effective date of the $PM_{2.5}$ area designation as promulgated by the Administrator.

Direct $PM_{2.5}$ emissions means solid particles emitted directly from an air emissions source or activity, or gaseous emissions or liquid droplets from an air emissions source or activity which condense to form particulate matter at ambient temperatures. Direct $PM_{2.5}$ emissions include elemental carbon, directly emitted organic carbon, directly emitted sulfate, directly emitted nitrate, and other inorganic particles (including but not limited to crustal material, metals, and sea salt).

Existing control measure means any Federally enforceable national, State, or local control measure that has been approved in the SIP and that results in reductions in emissions of $PM_{2.5}$ or $PM_{2.5}$ precursors in a nonattainment area.

Full implementation inventory is the projected RFP emission inventory for the year preceding the attainment date, representing a level of emissions that demonstrates attainment.

Milestone year inventory is the projected RFP emission inventory for the applicable RFP milestone year (*i.e.* 2009 and, where applicable, 2012).

$PM_{2.5}$ NAAQS means the particulate matter national ambient air quality standards (annual and 24-hour) codified at 40 CFR 50.7.

$PM_{2.5}$ design value for a nonattainment area is the highest of the three-year average concentrations calculated for the monitors in the area, in accordance with 40 CFR part 50, appendix N.

$PM_{2.5}$ attainment plan precursor means $S0_2$ and those other $PM_{2.5}$ precursors emitted by sources in the State which the State must evaluate for emission reduction measures to be included in its $PM_{2.5}$ nonattainment area or maintenance area plan.

$PM_{2.5}$ precursor means those air pollutants other than $PM_{2.5}$ direct emissions that contribute to the formation of $PM_{2.5}$. $PM_{2.5}$ precursors include $S0_2$, NO_X, volatile organic compounds, and ammonia.

Reasonable further progress (RFP) means the incremental emissions reductions toward attainment required under sections 172(c)(2) and 171(1).

Subpart 1 means the general attainment plan requirements found in subpart 1 of part D of title I of the Act.

§ 51.1001 Applicability of part 51.

The provisions in subparts A through X of this part apply to areas for purposes of the $PM_{2.5}$ NAAQS to the extent they are not inconsistent with the provisions of this subpart.

§ 51.1002 Submittal of State implementation plan.

(a) For any area designated by EPA as nonattainment for the $PM_{2.5}$ NAAQS, the State must submit a State implementation plan satisfying the requirements of section 172 of the Act and this subpart to EPA by the date prescribed by EPA which will be no later than 3 years from the date of designation.

(b) The State must submit a plan consistent with the requirements of section 110(a)(2) of the Act unless the State already has fulfilled this obligation for the purposes of implementing the $PM_{2.5}$ NAAQS.

(c) *Pollutants contributing to fine particle concentrations.* The State implementation plan must identify and evaluate sources of $PM_{2.5}$ direct emissions and $PM_{2.5}$ attainment plan precursors in accordance with §§ 51.1009 and 51.1010. After January 1, 2011, for purposes of establishing emissions limits under 51.1009 and 51.1010, States must establish such limits taking into consideration the condensable fraction of direct $PM_{2.5}$ emissions. Prior to this date, States are not prohibited from establishing source emission limits that include the condensable fraction of direct $PM_{2.5}$.

(1) The State must address sulfur dioxide as a $PM_{2.5}$ attainment plan precursor and evaluate sources of SO_2 emissions in the State for control measures.

(2) The State must address NO_X as a $PM_{2.5}$ attainment plan precursor and evaluate sources of NO_X emissions in the State for control measures, unless the State and EPA provide an appropriate technical demonstration for a specific area showing that NO_X emissions from sources in the State do not significantly contribute to $PM_{2.5}$ concentrations in the nonattainment area.

(3) The State is not required to address VOC as a $PM_{2.5}$ attainment plan precursor and evaluate sources of VOC emissions in the State for control measures, unless:

(i) the State provides an appropriate technical demonstration for a specific area showing that VOC emissions from sources in the State significantly contribute to $PM_{2.5}$ concentrations in the nonattainment area, and such demonstration is approved by EPA; or

(ii) The EPA provides such a technical demonstration.

(4) The State is not required to address ammonia as a $PM_{2.5}$ attainment plan precursor and evaluate sources of ammonia emissions from sources in the State for control measures, unless:

(i) The State provides an appropriate technical demonstration for a specific area showing that ammonia emissions from sources in the State significantly contribute to $PM_{2.5}$ concentrations in the

nonattainment area, and such demonstration is approved by EPA; or

(ii) The EPA provides such a technical demonstration.

(5) The State must submit a demonstration to reverse any presumption in this rule for a $PM_{2.5}$ precursor with respect to a particular nonattainment area, if the administrative record related to development of its SIP shows that the presumption is not technically justified for that area.

§ 51.1003 [Reserved]

§ 51.1004 Attainment dates.

(a) Consistent with section 172(a)(2)(A) of the Act, the attainment date for an area designated nonattainment for the $PM_{2.5}$ NAAQS will be the date by which attainment can be achieved as expeditiously as practicable, but no more than five years from the date of designation. The Administrator may extend the attainment date to the extent the Administrator determines appropriate, for a period no greater than 10 years from the date of designation, considering the severity of nonattainment and the availability and feasibility of pollution control measures.

(b) In the SIP submittal for each of its nonattainment areas, the State must submit an attainment demonstration justifying its proposed attainment date. For each nonattainment area, the Administrator will approve an attainment date at the same time the Administrator approves the attainment demonstration for the area, consistent with the attainment date timing provision of section 172(a)(2)(A) and paragraph (a) of this section.

(c) Upon a determination by EPA that an area designated nonattainment for the $PM_{2.5}$ NAAQS has attained the standard, the requirements for such area to submit attainment demonstrations and associated reasonably available control measures, reasonable further progress plans, contingency measures, and other planning SIPs related to attainment of the $PM_{2.5}$ NAAQS shall be suspended until such time as: the area is redesignated to attainment, at which time the requirements no longer apply; or EPA determines that the area has violated the $PM_{2.5}$ NAAQS, at which time the area is again required to submit such plans.

§ 51.1005 One-year extensions of the attainment date.

(a) Pursuant to section 172(a)(2)(C)(ii) of the Act, a State with an area that fails to attain the $PM_{2.5}$ NAAQS by its attainment date may apply for an initial 1-year attainment date extension if the State has complied with all requirements and commitments pertaining to the area in the applicable implementation plan, and:

(1) For an area that violates the annual $PM_{2.5}$ NAAQS as of its attainment date, the annual average concentration for the most recent year at each monitor is 15.0 $\mu g/m^3$ or less (calculated according to the data analysis requirements in 40 CFR part 50, appendix N).

(2) For an area that violates the 24-hour $PM_{2.5}$ NAAQS as of its attainment date, the 98th percentile concentration for the most recent year at each monitor is 65 $\mu g/m^3$ or less (calculated according to the data analysis requirements in 40 CFR part 50, appendix N).

(b) An area that fails to attain the $PM_{2.5}$ NAAQS after receiving a 1-year attainment date extension may apply for a second 1-year attainment date extension pursuant to section 172(a)(2)(C)(ii) if the State has complied with all requirements and commitments pertaining to the area in the applicable implementation plan, and:

(1) For an area that violates the annual $PM_{2.5}$ NAAQS as of its attainment date, the two-year average of annual average concentrations at each monitor, based on the first extension year and the previous year, is 15.0 $\mu g/m^3$ or less (calculated according to the data analysis requirements in 40 CFR part 50, appendix N).

(2) For an area that violates the 24-hour $PM_{2.5}$ NAAQS as of its attainment date, the two-year average of annual 98th percentile concentrations at each monitor, based on the first extension year and the previous year, is 65 $\mu g/m^3$ or less (calculated according to the data analysis requirements in 40 CFR part 50, appendix N).

§ 51.1006 Redesignation to nonattainment following initial designations for the $PM_{2.5}$ NAAQS.

Any area that is initially designated ''attainment/unclassifiable'' for the $PM_{2.5}$ NAAQS may be subsequently redesignated to nonattainment if ambient air quality data in future years indicate that such a redesignation is appropriate. For any such area that is redesignated to nonattainment for the $PM_{2.5}$ NAAQS, any absolute, fixed date that is applicable in connection with the requirements of this part is extended by a period of time equal to the length of time between the effective date of the initial designation for the $PM_{2.5}$ NAAQS and the effective date of redesignation, except as otherwise provided in this subpart.

§ 51.1007 Attainment demonstration and modeling requirements.

(a) For any area designated as nonattainment for the $PM_{2.5}$ NAAQS, the State must submit an attainment demonstration showing that the area will attain the annual and 24-hour standards as expeditiously as practicable. The demonstration must meet the requirements of § 51.112 and Appendix W of this part and must include inventory data, modeling results, and emission reduction analyses on which the State has based its projected attainment date. The attainment date justified by the demonstration must be consistent with the requirements of § 51.1004(a). The modeled strategies must be consistent with requirements in § 51.1009 for RFP and in § 51.1010 for RACT and RACM. The attainment demonstration and supporting air quality modeling should be consistent with EPA's $PM_{2.5}$ modeling guidance.

(b) *Required time frame for obtaining emissions reductions.* For each nonattainment area, the State implementation plan must provide for implementation of all control measures needed for attainment as expeditiously as practicable, but no later than the beginning of the year prior to the attainment date. Consistent with section 172(c)(1) of the Act, the plan must provide for implementation of all RACM and RACT as expeditiously as practicable. The plan also must include RFP milestones in accordance with § 51.1009, and control measures needed to meet these milestones, as necessary.

§ 51.1008 Emission inventory requirements for the $PM_{2.5}$ NAAQS.

(a) For purposes of meeting the emission inventory requirements of section 172(c)(3) of the Act for nonattainment areas, the State shall, no later than three years after designation:

(1) Submit to EPA Statewide emission inventories for direct $PM_{2.5}$ emissions and emissions of $PM_{2.5}$ precursors. For purposes of defining the data elements for these inventories, the $PM_{2.5}$ and $PM_{2.5}$ precursor-relevant data element requirements under subpart A of this part shall apply.

(2) Submit any additional emission inventory information needed to support an attainment demonstration and RFP plan ensuring expeditious attainment of the annual and 24-hour $PM_{2.5}$ standards.

(b) For inventories required for submission under paragraph (a) of this section, a baseline emission inventory is required for the attainment demonstration required under § 51.1007 and for meeting RFP requirements

under § 51.1009. As determined on the date of designation, the base year for this inventory shall be the most recent calendar year for which a complete inventory was required to be submitted to EPA pursuant to subpart A of this part. The baseline emission inventory for calendar year 2002 or other suitable year shall be used for attainment planning and RFP plans for areas initially designated nonattainment for the $PM_{2.5}$ NAAQS in 2004–2005.

§ 51.1009 Reasonable further progress (RFP) requirements.

(a) Consistent with section 172(c)(2) of the Act, State implementation plans for areas designated nonattainment for the $PM_{2.5}$ NAAQS must demonstrate reasonable further progress as provided in § 51.1009(b) through (h).

(b) If the State submits to EPA an attainment demonstration and State implementation plan for an area which demonstrates that it will attain the PM NAAQS within five years of the date of designation, the State is not required to submit a separate RFP plan. Compliance with the emission reduction measures in the attainment demonstration and State implementation plan will meet the requirements for achieving reasonable further progress for the area.

(c) For any area for which the State submits to EPA an approvable attainment demonstration and State implementation plan that demonstrates the area needs an attainment date of more than five years from the date of designation, the State also must submit an RFP plan. The RFP plan must describe the control measures that provide for meeting the reasonable further progress milestones for the area, the timing of implementation of those measures, and the expected reductions in emissions of direct $PM_{2.5}$ and $PM_{2.5}$ attainment plan precursors. The RFP plan is due to EPA within three years of the date of designation.

(1) For any State that submits to EPA an approvable attainment demonstration and State implementation plan justifying an attainment date of more than five and less than nine years from the date of designation, the RFP plan must include 2009 emissions milestones for direct $PM_{2.5}$ and $PM_{2.5}$ attainment plan precursors demonstrating that reasonable further progress will be achieved for the 2009 emissions year.

(2) For any area that submits to EPA an approvable attainment demonstration and State implementation plan justifying an attainment date of nine or ten years from the date of designation, the RFP plan must include 2009 and 2012 emissions milestones for direct $PM_{2.5}$ and $PM_{2.5}$ attainment plan precursors demonstrating that reasonable further progress will be achieved for the 2009 and 2012 emissions years.

(d) The RFP plan must demonstrate that in each applicable milestone year, emissions will be at a level consistent with generally linear progress in reducing emissions between the base year and the attainment year.

(e) For a multi-State nonattainment area, the RFP plans for each State represented in the nonattainment area must demonstrate RFP on the basis of common multi-State inventories. The States within which the area is located must provide a coordinated RFP plan. Each State in a multi-State nonattainment area must ensure that the sources within its boundaries comply with enforceable emission levels and other requirements that in combination with the reductions planned in other state(s) will provide for attainment as expeditiously as practicable and demonstrate reasonable further progress.

(f) In the benchmark RFP plan, the State must identify direct $PM_{2.5}$ emissions and $PM_{2.5}$ attainment plan precursors regulated under the $PM_{2.5}$ attainment plan and specify target emission reduction levels to be achieved during the milestone years. In developing the benchmark RFP plan, the State must develop emission inventory information for the geographic area included in the plan and conduct the following calculations:

(1) For direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor addressed in the attainment strategy, the full implementation reduction is calculated by subtracting the full implementation inventory from the baseline year inventory.

(2) The ''milestone date fraction'' is the ratio of the number of years from the baseline year to the milestone inventory year divided by the number of years from the baseline year to the full implementation year.

(3) For direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor addressed in the attainment strategy, a benchmark emission reduction is calculated by multiplying the full implementation reduction by the milestone date fraction.

(4) The benchmark emission level in the milestone year is calculated for direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor by subtracting the benchmark emission reduction from the baseline year emission level. The benchmark RFP plan is defined as a plan that achieves benchmark emission levels for direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor addressed in the attainment strategy for the area.

(5) In comparing inventories between baseline and future years for direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor, the inventories must be derived from the same geographic area. The plan must include emissions estimates for all types of emitting sources and activities in the geographic area from which the emission inventories for direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor addressed in the plan are derived.

(6) For purposes of establishing motor vehicle emissions budgets for transportation conformity purposes (as required in 40 CFR part 93) for a $PM_{2.5}$ nonattainment area, the State shall include in its RFP submittal an inventory of on-road mobile source emissions in the nonattainment area.

(g) The RFP plan due three years after designation must demonstrate that emissions for the milestone year are either:

(1) At levels that are roughly equivalent to the benchmark emission levels for direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor to be addressed in the plan; or

(2) At levels included in an alternative scenario that is projected to result in a generally equivalent improvement in air quality by the milestone year as would be achieved under the benchmark RFP plan.

(h) The equivalence of an alternative scenario to the corresponding benchmark plan must be determined by comparing the expected air quality changes of the two scenarios at the design value monitor location. This comparison must use the information developed for the attainment plan to assess the relationship between emissions reductions of the direct $PM_{2.5}$ emissions and each $PM_{2.5}$ attainment plan precursor addressed in the attainment strategy and the ambient air quality improvement for the associated ambient species.

§ 51.1010 Requirements for reasonably available control technology (RACT) and reasonably available control measures (RACM).

(a) For each $PM_{2.5}$ nonattainment area, the State shall submit with the attainment demonstration a SIP revision demonstrating that it has adopted all reasonably available control measures (including RACT for stationary sources) necessary to demonstrate attainment as expeditiously as practicable and to meet any RFP requirements. The SIP revision shall contain the list of the potential measures considered by the State, and

information and analysis sufficient to support the State's judgment that it has adopted all RACM, including RACT.

(b) In determining whether a particular emission reduction measure or set of measures must be adopted as RACM under section 172(c)(1) of the Act, the State must consider the cumulative impact of implementing the available measures. Potential measures that are reasonably available considering technical and economic feasibility must be adopted as RACM if, considered collectively, they would advance the attainment date by one year or more.

§ 51.1011 Requirements for mid-course review.

(a) Any State that submits to EPA an approvable attainment plan for a $PM_{2.5}$ nonattainment area justifying an attainment date of nine or ten years from the date of designation also must submit to EPA a mid-course review six years from the date of designation.

(b) The mid-course review for an area must include:

(1) A review of emissions reductions and progress made in implementing control measures to reduce emissions of direct $PM_{2.5}$ and $PM_{2.5}$ attainment plan precursors contributing to $PM_{2.5}$ concentrations in the area;

(2) An analysis of changes in ambient air quality data for the area;

(3) Revised air quality modeling analysis to demonstrate attainment;

(4) Any new or revised control measures adopted by the State, as necessary to ensure attainment by the attainment date in the approved SIP of the nonattainment area.

§ 51.1012 Requirement for contingency measures.

Consistent with section 172(c)(9) of the Act, the State must submit in each attainment plan specific contingency measures to be undertaken if the area fails to make reasonable further progress, or fails to attain the $PM_{2.5}$ NAAQS by its attainment date. The contingency measures must take effect without significant further action by the State or EPA.

[FR Doc. E7–6347 Filed 4–24–07; 8:45 am]

BILLING CODE 6560–50–P

[FR Doc. E7–19661 Filed 10–3–07; 8:45 am]
BILLING CODE 4310–05–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R04–OAR–2007–0835–200740(a); FRL–8475–4]

Approval of Implementation Plans of Kentucky: Clean Air Interstate Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is approving a revision to the Kentucky State Implementation Plan (SIP) submitted on July 19, 2007. This revision addresses the requirements of EPA's Clean Air Interstate Rule (CAIR), promulgated on May 12, 2005 and subsequently revised on April 28, 2006, and December 13, 2006. EPA has determined that the SIP revision fully implements the CAIR requirements for Kentucky. Therefore, as a consequence of the SIP approval, EPA will also withdraw the CAIR Federal Implementation Plans (FIPs) concerning sulfur dioxide (SO_2), nitrogen oxides (NO_X) annual, and NO_X ozone season emissions for Kentucky. The CAIR FIPs for all States in the CAIR region were promulgated on April 28, 2006, and subsequently revised on December 13, 2006.

CAIR requires States to reduce emissions of SO_2 and NO_X that significantly contribute to, and interfere with maintenance of, the national ambient air quality standards for fine particulates and/or ozone in any downwind state. CAIR establishes State budgets for SO_2 and NO_X and requires States to submit SIP revisions that implement these budgets in States that EPA concluded did contribute to nonattainment in downwind states. States have the flexibility to choose which control measures to adopt to achieve the budgets, including participating in the EPA-administered cap-and-trade programs. In the SIP revision that EPA is approving, Kentucky would meet CAIR requirements by participating in the EPA-administered cap-and-trade programs addressing SO_2, NO_X annual, and NO_X ozone season emissions.

DATES: This direct final rule is effective December 3, 2007 without further notice, unless EPA receives adverse comment by November 5, 2007. If EPA receives such comments, it will publish a timely withdrawal of the direct final rule in the **Federal Register** and inform the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R04–OAR–2007–0835, by one of the following methods:

1. *http://www.regulations.gov*: Follow the on-line instructions for submitting comments.
2. *E-mail: Lesane.Heidi@epa.gov.*
3. *Fax:* (404) 562–9019.
4. *Mail:* ''EPA–R04–OAR–2007–0835'', Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960.
5. *Hand Delivery or Courier:* Heidi Lesane, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. Such deliveries are only accepted during the Regional Office's normal hours of operation. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding Federal holidays.

Instructions: Direct your comments to Docket ID No. ''EPA–R04–OAR–2007–0835''. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit through *www.regulations.gov* or e-mail, information that you consider to be CBI or otherwise protected. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters and any form of encryption and should be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the electronic docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, i.e., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions concerning today's action, please contact Heidi LeSane, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. The telephone number is (404) 562–9074. Mrs. LeSane can also be reached via electronic mail at *LeSane.Heidi@epa.gov.*

SUPPLEMENTARY INFORMATION:

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I. What Action Is EPA Taking?

EPA is approving a revision to Kentucky's SIP, submitted on July 19, 2007. In its SIP revision, Kentucky meets CAIR requirements by requiring certain electric generating units (EGUs) to participate in the EPA-administered State CAIR cap-and-trade programs addressing SO_2, NO_X annual, and NO_X ozone season emissions. EPA has determined that the SIP as revised meets the applicable requirements of CAIR. As a consequence of this SIP approval, EPA will also issue a final rule to withdraw the FIPs concerning SO_2, NO_X annual, and NO_X ozone season emissions for Kentucky. This action will delete and reserve 40 CFR 52.940 and 40 CFR 52.941. The withdrawal of the CAIR FIPs for Kentucky is a conforming amendment that must be made once the SIP is approved because EPA's authority to issue the FIPs was premised on a deficiency in the SIP for Kentucky. Once the SIP is fully approved, EPA no longer has authority for the FIPs. Thus, EPA will not have the option of maintaining the FIPs following the full SIP approval. Accordingly, EPA does not intend to offer an opportunity for a public hearing or an additional opportunity for written public comment on the withdrawal of the FIPs.

II. What Is the Regulatory History of the CAIR and the CAIR FIPs?

The CAIR was published by EPA on May 12, 2005 (70 FR 25162). In this rule, EPA determined that 28 States and the District of Columbia contribute significantly to nonattainment and interfere with maintenance of the national ambient air quality standards (NAAQS) for fine particulates ($PM_{2.5}$) and /or 8-hour ozone in downwind States in the eastern part of the country. As a result, EPA required those upwind States to revise their SIPs to include control measures that reduce emissions of SO_2, which is a precursor to $PM_{2.5}$ formation, and/or NO_X, which is a precursor to both ozone and $PM_{2.5}$ formation. For jurisdictions that contribute significantly to downwind $PM_{2.5}$ nonattainment, CAIR sets annual State-wide emission reduction requirements (i.e., budgets) for SO_2 and annual State-wide emission reduction requirements for NO_X. Similarly, for jurisdictions that contribute significantly to 8-hour ozone nonattainment, CAIR sets State-wide emission reduction requirements for NO_X for the ozone season (May 1st to September 30th). Under CAIR, States may implement these reduction requirements by participating in the EPA-administered cap-and-trade programs or by adopting any other control measures.

CAIR explains to subject States what must be included in SIPs to address the requirements of section 110(a)(2)(D) of the Clean Air Act (CAA) with regard to interstate transport with respect to the 8-hour ozone and $PM_{2.5}$ NAAQS. EPA made national findings, effective on May 25, 2005, that the States had failed to submit SIPs meeting the requirements of section 110(a)(2)(D). The SIPs were due in July 2000, 3 years after the promulgation of the 8-hour ozone and $PM_{2.5}$ NAAQS. These findings started a 2-year clock for EPA to promulgate a FIP to address the requirements of section 110(a)(2)(D). Under CAA section 110(c)(1), EPA may issue a FIP anytime after such findings are made and must do so within two years unless a SIP revision correcting the deficiency is approved by EPA before the FIP is promulgated.

On April 28, 2006, EPA promulgated FIPs for all States covered by CAIR in order to ensure the emissions reductions required by CAIR are achieved on schedule. Each CAIR State is subject to the FIPs until the State fully adopts, and EPA approves, a SIP revision meeting the requirements of CAIR. The CAIR FIPs require EGUs to participate in the EPA-administered CAIR SO_2, NO_X annual, and NO_X ozone season trading programs, as appropriate. The CAIR FIP SO_2, NO_X annual, and NO_X ozone season trading programs impose essentially the same requirements as, and are integrated with, the respective CAIR SIP trading programs. The integration of the FIP and SIP trading programs means that these trading programs will work together to create effectively a single trading program for each regulated pollutant (SO_2, NO_X annual, and NO_X ozone season) in all States covered by the CAIR FIP or SIP trading program for that pollutant. The CAIR FIPs also allow States to submit abbreviated SIP revisions that, if approved by EPA, will automatically replace or supplement certain CAIR FIP provisions (e.g., the methodology for allocating NO_X allowances to sources in the State), while the CAIR FIP remains in place for all other provisions.

On April 28, 2006, EPA published two additional CAIR-related final rules that added the States of Delaware and New Jersey to the list of States subject to CAIR for $PM_{2.5}$ and announced EPA's final decisions on reconsideration of five issues, without making any substantive changes to the CAIR requirements.

III. What Are the General Requirements of CAIR and the CAIR FIPs?

CAIR establishes State-wide emission budgets for SO_2 and NO_X and is to be implemented in two phases. The first phase of NO_X reductions starts in 2009 and continues through 2014, while the first phase of SO_2 reductions starts in 2010 and continues through 2014. The second phase of reductions for both NO_X and SO_2 starts in 2015 and continues thereafter. CAIR requires States to implement the budgets by either: (1) Requiring EGUs to participate in the EPA-administered cap-and-trade programs; or (2) adopting other control measures of the State's choosing and demonstrating that such control measures will result in compliance with the applicable State SO_2 and NO_X budgets.

The May 12, 2005 and April 28, 2006 CAIR rules provide model rules that States must adopt (with certain limited changes, if desired) if they want to participate in the EPA-administered trading programs.

With two exceptions, only States that choose to meet the requirements of CAIR through methods that exclusively regulate EGUs are allowed to participate in the EPA-administered trading programs. One exception is for States that adopt the opt-in provisions of the model rules to allow non-EGUs individually to opt into the EPA-administered trading programs. The other exception is for States that include all non-EGUs from their NO_X SIP Call trading programs in their CAIR NO_X ozone season trading programs.

IV. What Are the Types of CAIR SIP Submittals?

States have the flexibility to choose the type of control measures they will use to meet the requirements of CAIR. EPA anticipates that most States will choose to meet the CAIR requirements by selecting an option that requires EGUs to participate in the EPA-administered CAIR cap-and-trade programs. For such States, EPA has provided two approaches for submitting and obtaining approval for CAIR SIP revisions. States may submit full SIP revisions that adopt the model CAIR cap-and-trade rules. If approved, these SIP revisions will fully replace the CAIR FIPs. Alternatively, States may submit abbreviated SIP revisions. These SIP revisions will not replace the CAIR FIPs; however, the CAIR FIPs provide that, when approved, the provisions in these abbreviated SIP revisions will be used instead of or in conjunction with, as appropriate, the corresponding provisions of the CAIR FIPs (e.g., the

NO_X allowance allocation methodology).

A State submitting a full SIP revision may either adopt regulations that are substantively identical to the model rules or incorporate by reference the model rules. CAIR provides that States may only make limited changes to the model rules if the States want to participate in the EPA-administered trading programs. A full SIP revision may change the model rules only by altering their applicability and allowance allocation provisions to:

1. Include NO_X SIP Call trading sources that are not EGUs under CAIR in the CAIR NO_X ozone season trading program;

2. Provide for allocation of NO_X annual or ozone season allowances by the State, rather than the Administrator of the EPA or the Administrator's duly authorized representative (Administrator), and using a methodology chosen by the State;

3. Provide for State allocation of NO_X annual allowances from the compliance supplement pool (CSP) using the State's choice of allowed, alternative methodologies; or

4. Allow units that are not otherwise CAIR units to opt individually into the CAIR SO_2, NO_X annual, or NO_X ozone season trading programs under the opt-in provisions in the model rules.

An approved CAIR full SIP revision addressing EGUs' SO_2, NO_X annual, or NO_X ozone season emissions will replace the CAIR FIP for that State for the respective EGU emissions.

V. Analysis of Kentucky's CAIR SIP Submittal

A. State Budgets for Allowance Allocations

The CAIR NO_X annual and ozone season budgets were developed from historical heat input data for EGUs. Using these data, EPA calculated annual and ozone season regional heat input values, which were multiplied by 0.15 pounds per million British thermal units (lb/mmBtu), for phase 1, and 0.125 lb/mmBtu, for phase 2, to obtain regional NO_X budgets for 2009–2014 and for 2015 and thereafter, respectively. EPA derived the State NO_X annual and ozone season budgets from the regional budgets using State heat input data adjusted by fuel factors.

The CAIR State SO_2 budgets were derived by discounting the tonnage of emissions authorized by annual allowance allocations under the Acid Rain Program under title IV of the CAA. Under CAIR, each allowance allocated in the Acid Rain Program for the years in phase 1 of CAIR (2010 through 2014) authorizes 0.50 ton of SO_2 emissions in the CAIR trading program, and each Acid Rain Program allowance allocated for the years in phase 2 of CAIR (2015 and thereafter) authorizes 0.35 ton of SO_2 emissions in the CAIR trading program.

In this action, EPA is approving Kentucky's SIP revision that adopts the budgets established for the Commonwealth in CAIR, i.e., 83,205 (2009–2014) and 69,337 (2015–thereafter) tons for NO_X annual emissions, 36,109 (2009–2014) and 30,651 (2015–thereafter) tons for NO_X ozone season emissions, and 188,773 (2010–2014) and 132,141 (2015–thereafter) tons for SO_2 emissions. Kentucky's SIP revision sets these budgets as the total amounts of allowances available for allocation for each year under the EPA-administered cap-and-trade programs.

B. CAIR Cap-and-Trade Programs

The CAIR NO_X annual and ozone-season model trading rules both largely mirror the structure of the NO_X SIP Call model trading rule in 40 CFR part 96, subparts A through I. While the provisions of the NO_X annual and ozone-season model rules are similar, there are some differences. For example, the NO_X annual model rule (but not the NO_X ozone season model rule) provides for a CSP, which is discussed below and under which allowances may be awarded for early reductions of NO_X annual emissions. As a further example, the NO_X ozone season model rule reflects the fact that the CAIR NO_X ozone season trading program replaces the NO_X SIP Call trading program after the 2008 ozone season and is coordinated with the NO_X SIP Call program. The NO_X ozone season model rule provides incentives for early emissions reductions by allowing banked, pre-2009 NO_X SIP Call allowances to be used for compliance in the CAIR NO_X ozone-season trading program. In addition, States have the option of continuing to meet their NO_X SIP Call requirement by participating in the CAIR NO_X ozone season trading program and including all their NO_X SIP Call trading sources in that program.

The provisions of the CAIR SO_2 model rule are also similar to the provisions of the NO_X annual and ozone season model rules. However, the SO_2 model rule is coordinated with the ongoing Acid Rain SO_2 cap-and-trade program under CAA title IV. The SO_2 model rule uses the title IV allowances for compliance, with each allowance allocated for 2010–2014 authorizing only 0.50 ton of emissions and each allowance allocated for 2015 and thereafter authorizing only 0.35 ton of emissions. Banked title IV allowances allocated for years before 2010 can be used at any time in the CAIR SO_2 cap-and-trade program, with each such allowance authorizing 1 ton of emissions. Title IV allowances are to be freely transferable among sources covered by the Acid Rain Program and sources covered by the CAIR SO_2 cap-and-trade program.

EPA also used the CAIR model trading rules as the basis for the trading programs in the CAIR FIPs. The CAIR FIP trading rules are virtually identical to the CAIR model trading rules, with changes made to account for federal rather than state implementation. The CAIR model SO_2, NO_X annual, and NO_X ozone season trading rules and the respective CAIR FIP trading rules are designed to work together as integrated SO_2, NO_X annual, and NO_X ozone season trading programs.

In the SIP revision, Kentucky chooses to implement its CAIR budgets by requiring EGUs to participate in EPA-administered cap-and-trade programs for SO_2, NO_X annual, and NO_X ozone season emissions. Kentucky has adopted a full SIP revision that adopts, with certain allowed changes discussed below, the CAIR model cap-and-trade rules for SO_2, NO_X annual, and NO_X ozone season emissions.

C. Applicability Provisions for Non-EGU NO_X SIP Call Sources

In general, the CAIR model trading rules apply to any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 megawatt electrical (MWe) producing electricity for sale.

States have the option of bringing in, for the CAIR NO_X ozone season program only, those units in the State's NO_X SIP Call trading program that are not EGUs as defined under CAIR. EPA advises States exercising this option to add the applicability provisions in the State's NO_X SIP Call trading rule for non-EGUs to the applicability provisions in 40 CFR 96.304 in order to include in the CAIR NO_X ozone season trading program all units required to be in the State's NO_X SIP Call trading program that are not already included under 40 CFR 96.304. Under this option, the CAIR NO_X ozone season program must cover all large industrial boilers and combustion turbines, as well as any small EGUs (i.e. units serving a generator with a nameplate capacity of 25 MWe or less)

that the State currently requires to be in the NO_X SIP Call trading program.

Kentucky has chosen to expand the applicability provisions of the CAIR NO_X ozone season trading program to include all non-EGUs in the State's NO_X SIP Call trading program. Kentucky has committed to revising the applicability section in its CAIR NO_X ozone season rule in order to clarify that, as intended by the State, units subject to its NO_X SIP Call program and brought into its CAIR program through the allowed expansion of the CAIR NO_X ozone season applicability provisions are to be treated as CAIR NO_X ozone season units and certain definitions from 401 KAR 51:001 apply to the provisions that bring these units into the CAIR program. EPA determined after review of Kentucky's final rules, and after Kentucky had adopted other necessary revisions to its CAIR rules, that these provisions needed clarification. However, while the clarifications are needed, EPA interprets Kentucky's current rule to provide that the NO_X SIP Call units are subject to the requirements for CAIR NO_X ozone season units and that the NO_X SIP Call definitions are used in applying the applicability provisions that bring in NO_X SIP Call units. In addition, Kentucky has committed to correct two citation references in its CAIR NO_X ozone season allowance allocation methodology needed in order to reference correctly its applicability section. EPA interprets Kentucky's current rule as applying the correct references.

Kentucky has also committed to revising the definitions of ''commence commercial operation'' and ''commence operation'' in its CAIR NO_X ozone season rule in order to clarify the deadlines, for meeting monitoring and reporting requirements, that apply to the NO_X SIP Call units that are brought into the CAIR program but do not serve generators producing electricity for sale, as intended by the State. EPA determined after review of Kentucky's final rules, and after Kentucky had adopted other necessary revisions to its CAIR rules, that these provisions needed clarification.

EPA has outlined these necessary revisions in a technical support document. EPA received a letter from Kentucky dated September 11, 2007, that provides a commitment to make these rule revisions in its CAIR rules in 2008. Specifically, in the September 11, 2007, letter, Kentucky commits to make the revisions discussed above to its CAIR NO_X Ozone Season trading rule, 401 KAR 51:220.

D. NO_X Allowance Allocations

Under the NO_X allowance allocation methodology in the CAIR model trading rules and in the CAIR FIP, NO_X annual and ozone season allowances are allocated to units that have operated for five years, based on heat input data from a three-year period that are adjusted for fuel type by using fuel factors of 1.0 for coal, 0.6 for oil, and 0.4 for other fuels. The CAIR model trading rules and the CAIR FIP also provide a new unit set-aside from which units without five years of operation are allocated allowances based on the units' prior year emissions.

States may establish in their SIP submissions a different NO_X allowance allocation methodology that will be used to allocate allowances to sources in the States if certain requirements are met concerning the timing of submission of units' allocations to the Administrator for recordation and the total amount of allowances allocated for each control period. In adopting alternative NO_X allowance allocation methodologies, States have flexibility with regard to:

1. The cost to recipients of the allowances, which may be distributed for free or auctioned;

2. The frequency of allocations;

3. The basis for allocating allowances, which may be distributed, for example, based on historical heat input or electric and thermal output; and

4. The use of allowance set-asides and, if used, their size.

Kentucky has chosen to replace the provisions of the CAIR NO_X annual and CAIR NO_X ozone season model trading rules concerning the allocation of NO_X annual and ozone season allowances with its own methodology. Kentucky has chosen to distribute 98% of its NO_X annual allowances based upon adjusted heat input. In Kentucky's final CAIR SIP submittal, Kentucky already made initial allocations for the control periods spanning from 2009 to 2014. In 2009, Kentucky will submit one-year allocations for the 2015 control period, and for every control period thereafter Kentucky will continue to submit allocations six years in advance. For example, in 2010, one-year allocations will be made for the 2016 control period; in 2011, one-year allocations will be made for the 2017 control period, etc. The remaining 2% of Kentucky's allowances will be held and sold as needed by the Commonwealth of Kentucky, with the proceeds to be deposited into Kentucky's general fund.

E. Allocation of NO_X Allowances From the Compliance Supplement Pool

The CAIR establishes a compliance supplement pool (CSP) to provide an incentive for early reductions in NO_X annual emissions. The CSP consists of 200,000 CAIR NO_X annual allowances of vintage 2009 for the entire CAIR region, and a State's share of the CSP is based upon the projected magnitude of the emission reductions required by CAIR in that State. States may distribute CSP allowances, one allowance for each ton of early reduction, to sources that make NO_X reductions during 2007 or 2008 beyond what is required by any applicable State or Federal emission limitation. States also may distribute CSP allowances based upon a demonstration of need for an extension of the 2009 deadline for implementing emission controls.

The CAIR annual NO_X model trading rule establishes specific methodologies for allocations of CSP allowances. States may choose an allowed, alternative CSP allocation methodology to be used to allocate CSP allowances to sources in the States.

Kentucky has chosen to modify the provisions of the CAIR NO_x annual model trading rule concerning the allocation of allowances from the CSP. Kentucky has chosen to distribute CSP allowances using an allocation methodology that continues to reward early reductions, but hinges on heat input data. Initially, the portion of the CSP that is available to a given source is determined by the following formula:

$$ERC_U = \frac{(BHI_U)}{BHI_T}(CSP_T)$$

Where: ERC_U is the Early Reduction Credit available to the unit, BHI_U is the Baseline Heat Input of the unit, BHI_T is the Baseline Heat Input from all sources within Kentucky, and CSP_T is 14,935 tons, the Early Reduction Credits available pursuant to 40 CFR 96.143(a).

Kentucky also makes available portions of the CSP for units that are able to demonstrate need, in a manner that is identical to 40 CFR 96.143(c). Remaining credits are then distributed on a pro rata basis, up to the total early reduction credits requested pursuant to 40 CFR 96.143(b), to those CAIR NO_X units with early reduction credits that exceeded the amount of credits made available by the previous calculation.

F. Individual Opt-In Units

The opt-in provisions of the CAIR SIP model trading rules allow certain non-EGUs (i.e., boilers, combustion turbines, and other stationary fossil-fuel-fired devices) that do not meet the

applicability criteria for a CAIR trading program to participate voluntarily in (i.e., opt into) the CAIR trading program. A non-EGU may opt into one or more of the CAIR trading programs. In order to qualify to opt into a CAIR trading program, a unit must vent all emissions through a stack and be able to meet monitoring, recordkeeping, and recording requirements of 40 CFR part 75. The owners and operators seeking to opt a unit into a CAIR trading program must apply for a CAIR opt-in permit. If the unit is issued a CAIR opt-in permit, the unit becomes a CAIR unit, is allocated allowances, and must meet the same allowance-holding and emissions monitoring and reporting requirements as other units subject to the CAIR trading program. The opt-in provisions provide for two methodologies for allocating allowances for opt-in units, one methodology that applies to opt-in units in general and a second methodology that allocates allowances only to opt-in units that the owners and operators intend to repower before January 1, 2015.

States have several options concerning the opt-in provisions. States may adopt the CAIR opt-in provisions entirely or may adopt them but exclude one of the methodologies for allocating allowances. States may also decline to adopt the opt-in provisions at all.

Kentucky has chosen to allow non-EGUs meeting certain requirements to opt into the CAIR NO_X annual trading program, including both of the opt-in allocation methods in the model rule.

Kentucky has chosen to allow non-EGUs meeting certain requirements to opt into the CAIR NO_X ozone season trading program, including both of the opt-in allocation methods in the model rule.

Kentucky has chosen to allow certain non-EGUs to opt into the CAIR SO_2 trading program, including both of the opt-in allocation methods in the model rule.

VI. Final Action

EPA is approving Kentucky's full CAIR SIP revision submitted on July 19, 2007. Under this SIP revision, Kentucky is choosing to participate in the EPA-administered cap-and-trade programs for SO_2, NO_X annual, and NO_X ozone season emissions. The SIP revision (interpreted and clarified as discussed above) meets the applicable requirements in 40 CFR 51.123(o) and (aa), with regard to NO_X annual and NO_X ozone season emissions, and 40 CFR 51.124(o), with regard to SO_2 emissions. Further, Kentucky has agreed to make the technical corrections to certain provisions as discussed above. Therefore, EPA has determined that the SIP as revised will meet the requirements of CAIR. As a consequence of the SIP approval, the Administrator of EPA will also issue, without providing an opportunity for a public hearing or an additional opportunity for written public comment, a final rule to withdraw the CAIR FIPs concerning SO_2, NO_X annual, and NO_X ozone season emissions for Kentucky. This action will delete and reserve 40 CFR 52.940 and 40 CFR 52.941.

EPA is approving the aforementioned changes to the SIP. EPA is publishing this rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no adverse comments. However, in the proposed rules section of this **Federal Register** publication, EPA is publishing a separate document that will serve as the proposal to approve the SIP revision should adverse comments be filed. This rule will be effective December 3, 2007 without further notice unless the Agency receives adverse comments by November 5, 2007.

If the EPA receives such comments, then EPA will publish a document withdrawing the final rule and informing the public that the rule will not take effect. All public comments received will then be addressed in a subsequent final rule based on the proposed rule. EPA will not institute a second comment period. Parties interested in commenting should do so at this time. If no such comments are received, the public is advised that this rule will be effective on December 3, 2007 and no further action will be taken on the proposed rule.

VII. Statutory and Executive Order Reviews

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a ''significant regulatory action'' and therefore is not subject to review by the Office of Management and Budget. For this reason, this action is also not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001). This action merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. Accordingly, the Administrator certifies that this rule will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). Because this rule approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law, it does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4).

This rule also does not have tribal implications because it will not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000). This action also does not have Federalism implications because it does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). This action merely approves a state rule implementing a Federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the CAA. This rule also is not subject to Executive Order 13045 ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), because it is not economically significant.

In reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. In this context, in the absence of a prior existing requirement for the State to use voluntary consensus standards (VCS), EPA has no authority to disapprove a SIP submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a SIP submission, to use VCS in place of a SIP submission that otherwise satisfies the provisions of the CAA. Thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply. This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other

required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by December 3, 2007. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects 40 CFR Part 52

Environmental protection, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: September 21, 2007.

J.I. Palmer, Jr.,

Regional Administrator, Region 4.

■ 40 CFR part 52 is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart S—Kentucky

■ 2. In § 52.920(c) Table 1 is amended under Chapter 51 by adding in numerical order the entries for ''401 KAR 51.210,'' ''401 KAR 51.220,'' and ''401 KAR 51.230'' to read as follows:

§ 52.920 Identification of plan.

* * * * *

(c) * * *

TABLE 1.—EPA APPROVED KENTUCKY REGULATIONS

State citation	Title/subject	State effective date	EPA approval date	Explanation
*	* * *	*	*	*
Chapter 51 Attainment and Maintenance of the National Ambient Air Quality Standards				
*	* * *	*	*	*
401 KAR 51.210	CAIR NO_X Annual Trading Program	2/2/2007	10/4/2007 [Insert citation of publication].	
401 KAR 51.220	CAIR NO_X Ozone Season Trading Program	6/13/2007	10/4/2007 [Insert citation of publication].	
401 KAR 51.230	CAIR SO_2 Trading Program	2/2/2007	10/4/2007 [Insert citation of publication].	
*	* * *	*	*	*

[FR Doc. E7–19327 Filed 10–3–07; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 82

[EPA–HQ–OAR–2003–0118; FRL–8477–7]

RIN 2060–AG12

Protection of Stratospheric Ozone: Notice 22 for Significant New Alternatives Policy Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Determination of acceptability.

SUMMARY: This Determination of Acceptability expands the list of acceptable substitutes for ozone-depleting substances under the U.S. Environmental Protection Agency's (EPA) Significant New Alternatives Policy (SNAP) program. The determinations concern new substitutes for use in the refrigeration and air conditioning sector.

DATES: This action is effective on October 4, 2007.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2003–0118 (continuation of Air Docket A–91–42). All electronic documents in the docket are listed in the index at *http://www.regulations.gov.* Although listed in the index, some information is not publicly available, i.e., Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Publicly available docket materials are available either electronically at *www.regulations.gov* or in hard copy at the EPA Air Docket (No. A–91–42), EPA/DC, EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Margaret Sheppard by telephone at (202) 343–9163, by facsimile at (202) 343–2362, by e-mail at *sheppard.margaret@epa.gov,* or by mail at U.S. Environmental Protection Agency, Mail Code 6205J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. Overnight or courier deliveries should be sent to the office location at 1310 L Street, NW., 10th floor, Washington, DC 20005.

For more information on the Agency's process for administering the SNAP program or criteria for evaluation of substitutes, refer to the original SNAP rulemaking published in the **Federal Register** on March 18, 1994 (59 FR 13044). Notices and rulemakings under the SNAP program, as well as other EPA publications on protection of stratospheric ozone, are available at EPA's Ozone Depletion World Wide Web site at *http://www.epa.gov/ozone/* including the SNAP portion at *http://www.epa.gov/ozone/snap/*.

SUPPLEMENTARY INFORMATION:

* * * * *

[FR Doc. 2010–11009 Filed 5–10–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52 and 81

[EPA–R05–OAR–2009–0928; EPA–R05–OAR–2010–0046; FRL–9147–3]

Approval and Promulgation of Implementation Plans and Designation of Areas for Air Quality Planning Purposes; Ohio; Indiana; Redesignation of the Ohio and Indiana Portions of the Cincinnati-Hamilton Area to Attainment for Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is approving the requests of Ohio and Indiana to redesignate the Ohio and Indiana portions of the Cincinnati-Hamilton, OH–KY–IN 8-hour ozone nonattainment area, "the Cincinnati-Hamilton area," to attainment for that standard, because these requests meet the statutory requirements for redesignation under the Clean Air Act (CAA). The Ohio Environmental Protection Agency (Ohio EPA) and the Indiana Department of Environmental Management (IDEM) submitted these requests on December 14, 2009, and January 21, 2010, respectively. (EPA will address the Kentucky portion of the Cincinnati-Hamilton area in a separate rulemaking action.)

These approvals involve several related actions. EPA is making a determination under the CAA that the Cincinnati-Hamilton area has attained the 1997 8-hour ozone National Ambient Air Quality Standard (NAAQS). The Cincinnati-Hamilton area includes Butler, Clermont, Clinton, Hamilton, and Warren Counties in Ohio, Lawrenceburg Township in Dearborn County, Indiana, and Boone, Campbell, and Kenton Counties in Kentucky. This determination is based on three years of complete, quality-assured ambient air quality monitoring data for the 2007–2009 ozone seasons that demonstrate that the 8-hour ozone NAAQS has been attained in the entire Cincinnati-Hamilton area. EPA is also approving, as revisions to the Ohio and Indiana State Implementation Plans (SIPs), the States' plans for maintaining the 8-hour ozone NAAQS through 2020 in the area.

EPA is approving the 2002 base year emissions inventory submitted by IDEM on June 13, 2007, as meeting the base year emissions inventory requirement of the CAA for the Indiana portion of the Cincinnati-Hamilton area. EPA is approving the 2005 base year emissions inventory submitted by Ohio EPA as part of its redesignation request as meeting the base year emissions inventory requirements of the CAA for the Ohio portion of the Cincinnati-Hamilton area. Finally, EPA finds adequate and is approving the States' 2015 and 2020 Motor Vehicle Emission Budgets (MVEBs) for the Ohio and Indiana portion of the Cincinnati-Hamilton area.

DATES: This final rule is effective May 11, 2010.

ADDRESSES: EPA has established dockets for this action: Docket ID No. EPA–R05–OAR–2009–0928 and ID No. EPA–R05–OAR–2010–0046. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *i.e.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. This facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays. We recommend that you telephone Kathleen D'Agostino, Environmental Engineer, at (312) 886–1767 before visiting the Region 5 office.

FOR FURTHER INFORMATION CONTACT: Kathleen D'Agostino, Environmental Engineer, Criteria Pollutant Section, Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886–1767, *dagostino.kathleen@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document whenever "we," "us," or "our" is used, we mean EPA. This supplementary information section is arranged as follows:

Table of Contents

I. What is the background for these actions?

The background for today's actions is discussed in detail in EPA's February 26, 2010, proposal (75 FR 8871). In that rulemaking, we noted that, under EPA regulations at 40 CFR part 50, the 8-hour ozone standard is attained when the three-year average of the annual fourth-highest daily maximum 8-hour average ozone concentrations is less than or equal to 0.08 ppm. (*See* 69 FR 23857 (April 30, 2004) for further information.) Under the CAA, EPA may redesignate nonattainment areas to attainment if sufficient complete, quality-assured data are available to determine that the area has attained the standard and if it meets the other CAA redesignation requirements in section 107(d)(3)(E).

The Ohio EPA and IDEM submitted requests to redesignate the Ohio and Indiana portions of the Cincinnati-Hamilton area to attainment for the 8-hour ozone standard on December 14, 2009, and January 21, 2010, respectively. The redesignation requests included three years of complete, quality-assured data for the period of 2007 through 2009, indicating the 8-hour NAAQS for ozone, as promulgated in 1997, had been attained for the Cincinnati-Hamilton area. The February 26, 2010, proposed rule provides a detailed discussion of how Ohio and Indiana met this and other CAA requirements.

II. What comments did we receive on the proposed rule?

EPA provided a 30-day review and comment period. The comment period closed on March 29, 2010. We received no comments on the proposed rule.

III. What action is EPA taking?

EPA is making a determination that the Cincinnati-Hamilton area has attained the 1997 8-hour ozone NAAQS. EPA is also approving the maintenance plan SIP revisions for the Ohio and Indiana portions of the Cincinnati-Hamilton area. EPA's approval of the maintenance plans is based on the States' demonstrations that the plans meet the requirements of section 175A of the CAA. After evaluating the redesignation requests submitted by Ohio and Indiana, EPA believes that the requests meet the redesignation criteria set forth in section 107(d)(3)(E) of the CAA. Therefore, EPA is approving the redesignation of the Ohio and Indiana portions of the Cincinnati-Hamilton area from nonattainment to attainment for the 1997 8-hour ozone NAAQS. EPA is also approving Ohio EPA's 2005 base year emissions inventory for the Ohio

portion of the Cincinnati-Hamilton area and IDEM's 2002 base year emissions inventory for Dearborn County as meeting the requirements of section 172(c)(3) of the CAA. Finally, EPA finds adequate and is approving the States' 2015 and 2020 MVEBs for Ohio and Indiana portions of the Cincinnati-Hamilton area.

In accordance with 5 U.S.C. 553(d), EPA finds there is good cause for this action to become effective immediately upon publication. This is because a delayed effective date is unnecessary due to the nature of a redesignation to attainment, which relieves the area from certain CAA requirements that would otherwise apply to it. The immediate effective date for this action is authorized under both 5 U.S.C. 553(d)(1), which provides that rulemaking actions may become effective less than 30 days after publication if the rule "grants or recognizes an exemption or relieves a restriction," and section 553(d)(3), which allows an effective date less than 30 days after publication "as otherwise provided by the agency for good cause found and published with the rule." The purpose of the 30-day waiting period prescribed in section 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. Today's rule, however, does not create any new regulatory requirements such that affected parties would need time to prepare before the rule takes effect. Rather, today's rule relieves the state of various requirements for this 8-hour ozone nonattainment area. For these reasons, EPA finds good cause under 5 U.S.C. 553(d)(3) for this action to become effective on the date of publication of this action.

IV. Statutory and Executive Order Reviews

Under the CAA, redesignation of an area to attainment and the accompanying approval of a maintenance plan under section 107(d)(3)(E) are actions that affect the status of a geographical area and do not impose any additional regulatory requirements on sources beyond those imposed by state law. A redesignation to attainment does not in and of itself create any new requirements, but rather results in the applicability of requirements contained in the CAA for areas that have been redesignated to attainment. Moreover, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. These actions do not impose additional requirements beyond those imposed by state law and the CAA. For that reason, these actions:

- Are not "significant regulatory actions" subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Do not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Are certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Do not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Do not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Are not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Are not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Are not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Do not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register.** A major rule cannot take effect until 60 days after it is published in the **Federal Register.** This action is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 12, 2010. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (*See* section 307(b)(2).)

List of Subjects

40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Volatile organic compounds.

40 CFR Part 81

Environmental protection, Air pollution control, National parks, Wilderness areas.

Dated: April 22, 2010.

Bharat Mathur,

Acting Regional Administrator, Region 5.

■ Parts 52 and 81, chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart P—Indiana

■ 2. Section 52.777 is amended by adding paragraphs (nn) and (oo) to read as follows:

§ 52.777 Control strategy: Photochemical oxidants (hydrocarbons).

* * * * *

(nn) Approval—Indiana's 2002 inventory satisfies the base year emissions inventory requirements of section 172(c)(3) of the Clean Air Act for the Indiana portion of the Cincinnati-Hamilton, OH–KY–IN area under the 1997 8-hour ozone standard.

(oo) Approval—On January 21, 2010, the Indiana Department of

Environmental Management submitted a request to redesignate the Indiana portion of the Cincinnati-Hamilton, OH–KY–IN area to attainment of the 8-hour ozone NAAQS. As part of the redesignation request, the State submitted a maintenance plan as required by section 175A of the Clean Air Act. Elements of the section 175 maintenance plan include a contingency plan and an obligation to submit a subsequent maintenance plan revision in 8 years as required by the Clean Air Act. The 2015 motor vehicle emissions budgets for the Ohio and Indiana portions of the Cincinnati-Hamilton, OH–KY–IN area are 31.73 tpd for VOC and 49.00 tpd for NO_X. The 2020 motor vehicle emissions budgets for the Ohio and Indiana portions of the area are 28.82 tpd for VOC and 34.39 tpd for NO_X.

* * * * *

Subpart KK—Ohio

■ 3. Section 52.1885 is amended by adding paragraphs (ff)(10) and (hh)(3) to read as follows:

§ 52.1885 Control strategy: Ozone.

* * * * *

(ff) * * *

(10) Approval—On December 14, 2009, the Ohio Environmental Protection Agency submitted a request to redesignate the Ohio portion of the Cincinnati-Hamilton, OH–KY–IN area to attainment of the 8-hour ozone NAAQS. As part of the redesignation request, the State submitted a maintenance plan as required by section 175A of the Clean Air Act. Elements of the section 175 maintenance plan include a contingency plan and an obligation to submit a subsequent maintenance plan revision in 8 years as required by the Clean Air Act. The 2015 motor vehicle emissions budgets for the Ohio and Indiana portions of the Cincinnati-Hamilton, OH–KY–IN area are 31.73 tpd for VOC and 49.00 tpd for NO_X. The 2020 motor vehicle emissions budgets for the Ohio and Indiana portions of the area are 28.82 tpd for VOC and 34.39 tpd for NO_X.

* * * * *

(hh) * * *

(3) Approval—Ohio's 2005 inventory satisfies the base year emissions inventory requirements of section 172(c)(3) of the Clean Air Act for the Ohio portion of the Cincinnati-Hamilton, OH–KY–IN area under the 1997 8-hour ozone standard.

PART 81—[AMENDED]

■ 4. The authority citation for part 81 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 5. Section 81.315 is amended by revising the entry for Cincinnati-Hamilton, OH–KY–IN in the table entitled "Indiana—Ozone (8-Hour Standard)" to read as follows:

§ 81.315 Indiana.

* * * * *

INDIANA—OZONE

[8-Hour standard]

Designated area	Designation [a]		Classification	
	Date [1]	Type	Date [1]	Type
* *	*	* *	*	*
Cincinnati-Hamilton, OH–KY–IN:				
Dearborn County (part)	May 11, 2010	Attainment		
* *	*	* *	*	*

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is June 15, 2004, unless otherwise noted.

* * * * *

■ 6. Section 81.336 is amended by revising the entry for Cincinnati-Hamilton, OH–KY–IN in the table entitled "Ohio-Ozone (8-Hour Standard)" to read as follows:

§ 81.336 Ohio.

* * * * *

OHIO—OZONE

[8-Hour standard]

Designated area	Designation [a]		Classification	
	Date [1]	Type	Date [1]	Type
* *	*	* *	*	*
Cincinnati-Hamilton, OH–KY–IN:				
Butler County	May 11, 2010	Attainment		
Clermont County				
Clinton County				
Hamilton County				
Warren County				
* *	*	* *	*	*

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is June 15, 2004, unless otherwise noted.

* * * * *

[FR Doc. 2010–11010 Filed 5–10–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–HQ–OAR–2007–1158; FRL–9147–4]

RIN 2060–AO71

Regulation of Fuels and Fuel Additives: Alternative Affirmative Defense Requirements for Ultra-Low Sulfur Diesel and Gasoline Benzene Technical Amendment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is issuing a direct final rule to amend the diesel sulfur regulations to allow refiners, importers, distributors, and retailers of highway diesel fuel the option to use an alternative affirmative defense if the Agency finds highway diesel fuel samples above the specified sulfur standard at retail facilities. This alternative defense consists of a comprehensive program of quality assurance sampling and testing that would cover all participating companies that produce and/or distribute highway diesel fuel if certain other conditions are met. The sampling and testing program would be carried out by an independent surveyor. The program would be conducted pursuant to a survey plan approved by EPA that is designed to achieve the same objectives as the current regulatory quality assurance requirement. This rule also amends the gasoline benzene regulations to allow disqualified small refiners the same opportunity to generate gasoline benzene credits as that afforded to non-small refiners.

DATES: This rule is effective on July 12, 2010 without further notice, unless EPA receives adverse comment by June 10, 2010. If EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that this rule, or the relevant provisions of this rule, will not take effect. The incorporation by reference of a certain publication listed in the regulations is approved by the Director of the Federal Register as of July 12, 2010.

Hearings: If EPA receives a request from a person wishing to speak at a public hearing by May 26, 2010, a public hearing will be held at a time and location to be announced in a subsequent **Federal Register** notice. To request to speak at a public hearing, send a request to the contact in **FOR FURTHER INFORMATION CONTACT**.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2007–1158, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–9744.
- *Mail:* Air and Radiation Docket, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460.
- *Hand Delivery:* EPA Docket Center, Room 3334, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC, Attention Air Docket ID No. EPA–HQ–OAR–2007–1158. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2007–1158. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will automatically be captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in www.regulations.gov or in hard copy at the Air Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Jaimee Dong, Compliance and Innovative Strategies Division, Office of Transportation and Air Quality, Office of Air and Radiation, Environmental Protection Agency, Mail Code 6405J, 1200 Pennsylvania Avenue, Washington, DC 20460; telephone number: (202) 343–9672; fax number: (202) 343–2800; e-mail address: *Dong.Jaimee@epa.gov.*

SUPPLEMENTARY INFORMATION:

Why is EPA using a direct final rule?

EPA is publishing this rule without a prior proposed rule because we view this as a noncontroversial action and anticipate no adverse comment. However, in the "Proposed Rules" section of today's **Federal Register,** we are publishing a separate document that will serve as the proposed rule to amend the diesel sulfur regulations and the gasoline benzene regulations if adverse comments are received on this direct final rule. We do not intend to institute a second comment period on this action. Any parties interested in commenting must do so at this time. For further information about commenting on this rule, see the **ADDRESSES** section of this document.

If EPA receives adverse comment on a distinct provision of this rulemaking, we will publish a timely withdrawal in the **Federal Register** indicating which provisions we are withdrawing. The provisions that are not withdrawn will become effective on the date set out above, notwithstanding adverse comment on any other provision. We will address all public comments in any subsequent final rule based on the proposed rule.

abuse, Foreign relations, Government contracts, Grant programs—health, Grant programs—veterans, Health care, Health facilities, Health professions, Health records, Homeless, Medical and dental schools, Medical devices, Medical research, Mental health programs, Nursing homes, Philippines, Reporting and recordkeeping requirements, Scholarships and fellowships, Travel and transportation expenses, Veterans.

Dated: May 6, 2010.

Robert C. McFetridge,

Director, Regulation Policy and Management, Office of the General Counsel.

For the reasons stated in the preamble, VA proposes to amend 38 CFR part 17 as follows:

PART 17—MEDICAL

1. The authority citation for part 17 continues to read as follows:

Authority: 38 U.S.C. 501, 1721, and as noted in specific sections.

2. Amend § 17.38 by revising paragraph (c)(5) to read as follows:

§ 17.38 Medical benefits package.

* * * * *

(c) * * *

(5) Hospital and outpatient care for a veteran who is either a patient or inmate in an institution of another government agency if that agency has a duty to give the care or services. This exclusion does not apply to veterans who are released from incarceration in a prison or jail into a temporary housing program (such as a community residential re-entry center or halfway house).

* * * * *

[FR Doc. 2010–11177 Filed 5–11–10; 8:45 am]

BILLING CODE P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52 and 81

[EPA–R04–OAR–2010–0134–201007; FRL–9150–1]

Approval and Promulgation of Implementation Plans and Designation of Areas for Air Quality Planning Purposes; Kentucky; Redesignation of the Kentucky Portion of the Cincinnati-Hamilton 1997 8-Hour Ozone Nonattainment Area to Attainment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On January 29, 2010, the Commonwealth of Kentucky, through the Kentucky Energy and Environment Cabinet, Division for Air Quality (DAQ), submitted a request to redesignate the Kentucky portion of the tri-state Cincinnati-Hamilton 8-hour ozone nonattainment area (the "tri-state Cincinnati-Hamilton Area") to attainment for the 1997 8-hour ozone national ambient air quality standards (NAAQS); and to approve the state implementation plan (SIP) revision containing a maintenance plan for the Kentucky portion of the tri-state Cincinnati-Hamilton Area. The tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment area is composed of Boone, Campbell and Kenton Counties in Kentucky (hereafter also referred to as "Northern Kentucky"); Butler, Clermont, Clinton, Hamilton and Warren Counties in Ohio; and a portion of Dearborn County in Indiana. In this action, EPA is proposing to: Determine that the tri-state Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS; approve Kentucky's redesignation request for Boone, Campbell and Kenton Counties in Kentucky as part of the tri-state Cincinnati Area; approve the 1997 8-hour ozone maintenance plan for Northern Kentucky, including the motor vehicle emission budgets (MVEBs) for nitrogen oxides (NO_X) and volatile organic compounds (VOC) for the years 2015 and 2020; and approve the 2008 emissions inventory for Northern Kentucky as meeting the requirements of the Clean Air Act (CAA). EPA's proposed approval of Kentucky's redesignation request is based on the belief that Kentucky's request meets the criteria for redesignation to attainment specified in the CAA, including the determination that the entire tri-state Cincinnati-Hamilton ozone nonattainment area has attained the 1997 8-hour ozone NAAQS. In a separate rulemaking action, EPA has proposed to approve redesignation requests and maintenance plans submitted by Ohio and Indiana for their respective portions of this 1997 8-hour ozone area.

In this action, EPA is also notifying the public of the status of EPA's adequacy determination for the new 2015 and 2020 MVEBs that are contained in the 1997–8-hour ozone maintenance plan for Northern Kentucky. MVEBs for the Ohio and Indiana portions of this Area are included in the Ohio and Indiana submittals, and are being addressed through EPA's separate action for those submissions. EPA is also in the process of rulemaking on a new 8-hour ozone NAAQS. Today's actions, however, relate only to the 1997 8-hour ozone NAAQS.

DATES: Comments must be received on or before June 11, 2010.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R04–OAR–2010–0134, by one of the following methods:

1. *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.

2. *E-mail: benjamin.lynorae@epa.gov.*

3. *Fax:* (404) 562–9019.

4. *Mail:* EPA–R04–OAR–2010–0134, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960.

5. *Hand Delivery or Courier:* Ms. Lynorae Benjamin, Chief, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. Such deliveries are only accepted during the Regional Office's normal hours of operation. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding Federal holidays.

Instructions: Direct your comments to Docket ID No. EPA–R04–OAR–2010–0134. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit through *http://www.regulations.gov* or e-mail, information that you consider to be CBI or otherwise protected. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to

technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket: All documents in the electronic docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *i.e.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Ms. Jane Spann or Mr. Zuri Farngalo of the Regulatory Development Section, in the Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. Jane Spann may be reached by phone at (404) 562–9029, or via electronic mail at *spann.jane@epa.gov.* The telephone number for Mr. Farngalo is (404) 562–9152, and the electronic mail is *farngalo.zuri@epa.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. What proposed actions is EPA taking?

EPA is proposing several related actions, which are summarized below and described in greater detail throughout this notice of rulemaking: (1) To determine that the tri-state Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS; (2) to approve the Commonwealth of Kentucky's request to redesignate the Kentucky portion of the tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment area (Boone, Campbell and Kenton Counties in Kentucky) to attainment for the 1997 8-hour ozone NAAQS under section 107(d)(3)(E) of the CAA; (3) to approve under section 172(c)(3) the emissions inventory submitted with the maintenance plan; and (4) to approve under section 175A Kentucky's 1997 8-hour ozone NAAQS maintenance plan into the Kentucky SIP, including the associated MVEBs. These proposed actions will be revisions to the Kentucky SIP pursuant to section 110 of the CAA. In addition, and related to today's actions, EPA is also notifying the public of the status of EPA's adequacy determination for the Northern Kentucky MVEBs.

First, EPA is proposing to determine that the tri-state Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS, based on the most recent three years of complete, quality assured monitoring data. EPA further proposes to determine that the Area has met the requirements for redesignation under section 107(d)(3)(E) of the CAA if EPA's proposed approval of the emissions inventory for Northern Kentucky is finalized. In a separate action, EPA has proposed approval of the redesignation requests and maintenance plans for the Ohio and Indiana portions of the tri-state Cincinnati-Hamilton Area (75 FR 8871, February 26, 2010). In this action, EPA is now proposing to approve a request to redesignate the Kentucky portion of the Area and to change the legal designation of Boone, Campbell and Kenton Counties in Kentucky from nonattainment to attainment for the 1997 8-hour ozone NAAQS.

Second, EPA is proposing to approve under section 172(c)(3) Kentucky's 2008 emissions inventory included in the maintenance plan for Northern Kentucky as meeting the requirements of that section. In coordination with Ohio and Indiana, Kentucky selected 2008 as "the attainment year" for the tri-state Cincinnati-Hamilton Area for the purpose of demonstrating attainment of the 1997 8-hour ozone NAAQS. This emissions inventory identifies the level of emissions in the Area, which is sufficient to attain the 1997 8-hour ozone NAAQS. Please see section IX of this rulemaking for more detail on Kentucky's 2008 emission inventory.

Third, EPA is proposing to approve Kentucky's 1997 8-hour ozone NAAQS maintenance plan for Northern Kentucky as meeting the requirements of section 175A of the CAA, such approval being one of the CAA criteria for redesignation to attainment. The maintenance plan is designed to help keep the tri-state Cincinnati-Hamilton Area in attainment of the 1997 8-hour ozone NAAQS through 2020. Consistent with the CAA, the maintenance plan that EPA is proposing to approve today also includes 2015 and 2020 NO_X and VOC MVEBs. EPA is proposing to approve (into the Kentucky's SIP) the 2015 and 2020 MVEBs that are included as part of Kentucky's maintenance plan for the 1997 8-hour ozone NAAQS. The adequacy comment period for these MVEBs closed on March 5, 2010, and EPA did not receive any comments. (See section VIII of this proposed rulemaking.) Notably, these MVEBs apply only to Northern Kentucky. MVEBs contained in the Ohio's and Indiana's submittals for the remainder of the tri-state Cincinnati Area were addressed in a separate action (75 FR 8871, February 26, 2010).

EPA is also notifying the public of the status of EPA's adequacy process for the newly-established 2015 and 2020 NO_X and VOC MVEBs for Northern Kentucky. The MVEBs for the Ohio and Indiana portions of this 1997 8-hour ozone area are being addressed in a separate action. The Adequacy comment period for the Northern Kentucky 2015 and 2020 MVEBs began on February 3, 2010, with EPA's posting of the availability of this submittal on EPA's Adequacy Web site (*http://www.epa.gov/otaq/stateresources/transconf/currsips.htm*). The adequacy comment period for these MVEBs closed on March 5, 2010. EPA did not receive any adverse comments or requests for Kentucky's submission. Please see section VIII of this proposed rulemaking for further explanation of this process, and for more details on the MVEBs determination.

Today's notice of proposed rulemaking is in response to Kentucky's January 29, 2010, SIP submittal requesting the redesignation of Boone, Campbell and Kenton Counties in Kentucky as part of the tri-state Cincinnati-Hamilton 1997 8-hour ozone area, and includes SIP revisions

addressing the specific issues summarized above and the necessary elements for redesignation described in sections 107(d)(3)(E) and 175A of the CAA.

II. What is the background for EPA's proposed actions?

Ground-level ozone is not emitted directly by sources. Rather, emissions of NO_X and VOC react in the presence of sunlight to form ground-level ozone. NO_X and VOC are referred to as precursors of ozone. The CAA establishes a process for air quality management through the NAAQS.

On July 18, 1997, EPA promulgated a revised 8-hour ozone standard of 0.08 parts per million (ppm). This standard is more stringent than the previous 1-hour ozone standard. Under EPA regulations at 40 CFR part 50, the 1997 8-hour ozone standard is attained when the 3-year average of the annual fourth-highest daily maximum 8-hour average ambient air quality ozone concentrations is less than or equal to 0.08 ppm (0.084 ppm when rounding is considered). (*See* 69 FR 23857 (April 30, 2004) for further information.) Ambient air quality monitoring data for the 3-year period must meet a data completeness requirement. The ambient air quality monitoring data completeness requirement is met when the average percent of days with valid ambient monitoring data is greater than 90 percent, and no single year has less than 75 percent data completeness as determined in Appendix I of part 50. Specifically, section 2.3 of 40 CFR part 50, Appendix I, "*Comparisons with the Primary and Secondary Ozone Standards*" states:

"The primary and secondary ozone ambient air quality standards are met at an ambient air quality monitoring site when the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration is less than or equal to 0.08 ppm. The number of significant figures in the level of the standard dictates the rounding convention for comparing the computed 3-year average annual fourth-highest daily maximum 8-hour average ozone concentration with the level of the standard. The third decimal place of the computed value is rounded, with values equal to or greater than 5 rounding up. Thus, a computed 3-year average ozone concentration of 0.085 ppm is the smallest value that is greater than 0.08 ppm."

The CAA required EPA to designate as nonattainment any area that was violating the 1997 8-hour ozone NAAQS based on the three most recent years of ambient air quality data. The tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment area was initially designated nonattainment for the 1997 8-hour ozone standard using 2001–2003 ambient air quality data. EPA published a final designations rulemaking for the NAAQS on April 30, 2004 (69 FR 23857).

Title I, Part D of the CAA contains two sets of provisions—subpart 1 and subpart 2—that address planning and control requirements for ozone nonattainment areas. Subpart 1 (which EPA refers to as "basic" nonattainment) contains general, less prescriptive, requirements for nonattainment areas for any pollutant—including ozone—governed by a NAAQS. Subpart 2 (which EPA refers to as "classified" nonattainment) provides more specific requirements for certain ozone nonattainment areas. Some 1997 8-hour ozone nonattainment areas were subject only to the provisions of subpart 1. Other 1997 8-hour ozone nonattainment areas were classified as subpart 2 areas and were subject to the provisions of subpart 2 in addition to subpart 1. Under EPA's Phase I 8-Hour Ozone Implementation Rule (69 FR 23857) (Phase I Rule), signed on April 15, 2004, and published April 30, 2004, an area was classified under subpart 2 based on its 8-hour ozone design value (*i.e.,* the 3-year average of the annual fourth highest daily maximum 8-hour average ozone concentrations), if it had a 1-hour design value at or above 0.121 ppm (the lowest 1-hour design value in Table 1 of subpart 2). All other areas were covered under subpart 1, based upon their 8-hour ambient air quality design values.

Northern Kentucky (as part of the bi-state Cincinnati-Hamilton Area) was originally designated as a moderate nonattainment area for the 1-hour ozone NAAQS on November 6, 1991 (56 FR 56694). On June 19, 2000 (65 FR 37879), the Kentucky portion of the Cincinnati-Hamilton 1-hour nonattainment area was redesignated as attainment for the 1-hour ozone NAAQS, and was considered to be a maintenance area subject to a CAA section 175A maintenance plan for the 1-hour NAAQS. On April 30, 2004, EPA designated the tri-state Cincinnati-Hamilton Area (which then included Boone, Campbell and Kenton Counties in Kentucky; Butler, Clermont, Clinton, Hamilton and Warren Counties in Ohio; and a portion of Dearborn County in Indiana) under subpart 1 as a "basic" 1997 8-hour ozone NAAQS nonattainment area (69 FR 23857, April 30, 2004).

As part of the 2004 designations, EPA also promulgated an implementation rule—the Phase I Rule. Various aspects of EPA's Phase I Rule were challenged in court. On December 22, 2006, the U.S. Court of Appeals for the District of Columbia Circuit (DC Circuit Court) vacated EPA's Phase I Rule (69 FR 23951, April 30, 2004). *South Coast Air Quality Management Dist. (SCAQMD)* v. *EPA,* 472 F.3d 882 (DC Cir. 2006). On June 8, 2007, in response to several petitions for rehearing, the DC Circuit Court clarified that the Phase I Rule was vacated only with regard to those parts of the Rule that had been successfully challenged. The Phase I Rule provisions related to classifications for areas currently classified under subpart 2 of title I, part D of the CAA as 1997 8-hour ozone NAAQS nonattainment areas, the 1997 8-hour ozone NAAQS attainment dates and the timing for emissions reductions needed for attainment of the 1997 8-hour ozone NAAQS remain effective. The June 8th decision left intact the Court's rejection of EPA's reasons for implementing the 1997 8-hour standard in certain nonattainment areas under subpart 1 in lieu of subpart 2. By limiting the vacatur, the Court let stand EPA's revocation of the 1-hour standard and those anti-backsliding provisions of the Phase I Rule that had not been successfully challenged. The June 8th decision affirmed the December 22, 2006, decision that EPA had improperly failed to retain measures required for 1-hour nonattainment areas under the anti-backsliding provisions of the regulations: (1) Nonattainment area New Source Review (NSR) requirements based on an area's 1-hour nonattainment classification; (2) Section 185 penalty fees for 1-hour severe or extreme nonattainment areas; and (3) measures to be implemented pursuant to section 172(c)(9) or 182(c)(9) of the CAA, on the contingency of an area not making reasonable further progress toward attainment of the 1-hour NAAQS, or for failure to attain that NAAQS. The June 8th decision clarified that the Court's reference to conformity requirements for anti-backsliding purposes was limited to requiring the continued use of 1-hour motor vehicle emissions budgets until 1997 8-hour ozone NAAQS budgets were available for 8-hour ozone conformity determinations, which is already required under EPA's conformity regulations. The Court thus clarified that 1-hour ozone conformity determinations are not required for anti-backsliding purposes.

For the reasons set forth below, EPA does not believe that the Court's rulings alter any requirements relevant to this redesignation action so as to preclude redesignation, nor does EPA believe the

Court's ruling prevents EPA from proposing or ultimately finalizing this redesignation. EPA believes that the Court's December 22, 2006, and June 8, 2007, decisions impose no impediment to moving forward with redesignation of Northern Kentucky to attainment, because even in light of the Court's decision, redesignation is appropriate under the relevant redesignation provisions of the CAA and longstanding policies regarding redesignation requests.

With respect to the 1997 8-hour ozone NAAQS, the Court's ruling rejected EPA's reasons for classifying areas under subpart 1 for the 1997 8-hour ozone NAAQS, and remanded that matter back to the Agency. In its January 16, 2009, proposed rulemaking in response to the *SCAQMD* decision, EPA has proposed to classify the tri-state Cincinnati-Hamilton Area (of which Northern Kentucky is a part) under subpart 2 as a moderate area (74 FR 2936). If EPA finalizes this rulemaking, the requirements under subpart 2 will become applicable when they are due. EPA proposed a deadline for submission of these requirements of one year after the effective date of the final rulemaking classifying this and other areas (74 FR 2940–2941). Although a future final decision by EPA to classify this Area under subpart 2 would trigger additional future requirements for the Area, EPA believes that this does not preclude this redesignation from being approved. This belief is based upon: (1) EPA's longstanding policy of evaluating requirements in accordance with the requirements due at the time redesignation request is submitted; and (2) consideration of the inequity of applying retroactively any requirements that might in the future be applied.

First, at the time the redesignation request was submitted, the tri-state Cincinnati-Hamilton Area was not classified under subpart 2, nor were subpart 2 requirements yet due for this Area. Under EPA's longstanding interpretation of section 107(d)(3)(E) of the CAA, to qualify for redesignation, states requesting redesignation to attainment must meet only the relevant SIP requirements that came due prior to the submittal of a complete redesignation request. September 4, 1992, Calcagni Memorandum ("Procedures for Processing Requests to Redesignate Areas to Attainment," Memorandum from John Calcagni, Director, Air Quality Management Division). *See also* Michael Shapiro Memorandum, September 17, 1993, and 60 FR 12459, 12465–66 (March 7, 1995) (Redesignation of Detroit-Ann Arbor, Michigan); *Sierra Club* v *EPA,* 375 F.3d 537 (7th Cir. 2004) (upholding this interpretation); 68 FR 25418, 25424, 25427 (May 12, 2003) (redesignation of St. Louis, Missouri).

Moreover, it would be inequitable to retroactively apply any new SIP requirements that were not applicable at the time the request was submitted. The DC Circuit Court has recognized the inequity in such retroactive rulemaking (*see Sierra Club* v. *Whitman* 285 F.3d 63 (DC Cir. 2002)), in which the Court upheld a district court's ruling refusing to make retroactive an EPA determination of nonattainment that was past the statutory due date. Such a determination would have resulted in the imposition of additional requirements on the area. The Court stated, "[a]lthough EPA failed to make the nonattainment determination within the statutory frame, Sierra Club's proposed solution only makes the situation worse. Retroactive relief would likely impose large costs on the states, which would face fines and suits for not implementing air pollution prevention plans in 1997, even though they were not on notice at the time." *Id.* at 68. Similarly here, it would be unfair to penalize the area by applying to it for purpose of redesignation, additional SIP requirements under subpart 2 that were not in effect or yet due at the time it submitted its redesignation request, or the time that the tri-state Cincinnati-Hamilton Area attained the standard.

With respect to the requirements under the 1-hour ozone NAAQS, Northern Kentucky had been redesignated attainment subject to a maintenance plan under section 175A. The DC Circuit Court's decisions do not impact redesignation requests for these types of areas, except to the extent that the Court, in its June 8th decision, clarified that for those areas with 1-hour MVEBs in their maintenance plans, anti-backsliding requires that those 1-hour budgets must be used for 8-hour conformity determinations until they are replaced by 1997 8-hour budgets. To meet this requirement, conformity determinations in such areas must comply with the applicable requirements of EPA's conformity regulations at 40 CFR part 93.

With regard to the anti-backsliding provisions for the 1-hour NAAQS that the DC Circuit Court found were not properly retained, Northern Kentucky is an attainment area subject to a maintenance plan for the 1-hour NAAQS, and 1-hour anti-backsliding requirements no longer apply to an area that is redesignated to attainment of the 1-hour ozone NAAQS. As a result, the decisions in *SCAQMD* should not alter any requirements that would preclude EPA from finalizing the redesignation of Northern Kentucky to attainment for the 1997 8-hour ozone NAAQS.

On January 29, 2010, Kentucky requested that EPA redesignate the Kentucky portion of the tri-state Cincinnati-Hamilton Area to attainment for the 1997 8-hour ozone NAAQS. The redesignation request included three years of complete, quality-assured ambient air quality data for the ozone seasons (March 1st through October 31st) of 2007–2009, demonstrating that the 1997 8-hour ozone NAAQS has been achieved for the entire tri-state Cincinnati-Hamilton Area. Under the CAA, nonattainment areas may be redesignated to attainment if EPA determines that the most recent three years of complete, quality-assured data show that the Area has attained the standard, and the Area meets the other redesignation requirements set forth in CAA section 107(d)(3)(E).

III. What are the Criteria for Redesignation?

The CAA provides the requirements for redesignating a nonattainment area to attainment. Specifically, section 107(d)(3)(E) of the CAA allows for redesignation providing that: (1) The Administrator determines that the area has attained the applicable NAAQS; (2) the Administrator has fully approved the applicable implementation plan for the area under section 110(k); (3) the Administrator determines that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable SIP and applicable Federal air pollutant control regulations and other permanent and enforceable reductions; (4) the Administrator has fully approved a maintenance plan for the area as meeting the requirements of section 175A; and (5) the state containing such area has met all requirements applicable to the area for purposes of redesignation under section 110 and part D of the CAA.

EPA provided guidance on redesignation in the General Preamble for the Implementation of title I of the CAA Amendments of 1990, on April 16, 1992 (57 FR 13498), and supplemented this guidance on April 28, 1992 (57 FR 18070). EPA has provided further guidance on processing redesignation requests in the following documents:

1. "Ozone and Carbon Monoxide Design Value Calculations," Memorandum from Bill Laxton, Director, Technical Support Division, June 18,1990;

2. "Maintenance Plans for Redesignation of Ozone and Carbon

Monoxide Nonattainment Areas," Memorandum from G. T. Helms, Chief, Ozone/Carbon Monoxide Programs Branch, April 30, 1992;

3. "Contingency Measures for Ozone and Carbon Monoxide (CO) Redesignations," Memorandum from G. T. Helms, Chief, Ozone/Carbon Monoxide Programs Branch, June 1, 1992;

4. "Procedures for Processing Requests to Redesignate Areas to Attainment," Memorandum from John Calcagni, Director, Air Quality Management Division, September 4, 1992 (hereafter referred to as the "Calcagni Memorandum");

5. "State Implementation Plan (SIP) Actions Submitted in Response to Clean Air Act (CAA) Deadlines," Memorandum from John Calcagni, Director, Air Quality Management Division, October 28, 1992;

6. "Technical Support Documents (TSDs) for Redesignation of Ozone and Carbon Monoxide (CO) Nonattainment Areas," Memorandum from G. T. Helms, Chief, Ozone/Carbon Monoxide Programs Branch, August 17, 1993;

7. "State Implementation Plan (SIP) Requirements for Areas Submitting Requests for Redesignation to Attainment of the Ozone and Carbon Monoxide (CO) National Ambient Air Quality Standards (NAAQS) On or After November 15, 1992," Memorandum from Michael H. Shapiro, Acting Assistant Administrator for Air and Radiation, September 17, 1993;

8. "Use of Actual Emissions in Maintenance Demonstrations for Ozone and CO Nonattainment Areas," Memorandum from D. Kent Berry, Acting Director, Air Quality Management Division, November 30, 1993;

9. "Part D New Source Review (Part D NSR) Requirements for Areas Requesting Redesignation to Attainment," Memorandum from Mary D. Nichols, Assistant Administrator for Air and Radiation, October 14, 1994; and

10. "Reasonable Further Progress, Attainment Demonstration, and Related Requirements for Ozone Nonattainment Areas Meeting the Ozone National Ambient Air Quality Standard," Memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, May 10, 1995.

IV. Why is EPA proposing these actions?

On January 29, 2010, Kentucky requested redesignation of Northern Kentucky (as part of the tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment area) to attainment for the 1997 8-hour ozone NAAQS. EPA's preliminary evaluation indicates that the tri-state Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS and that Northern Kentucky, upon final approval of its 2008 emissions inventory, meets the requirements for redesignation set forth in section 107(d)(3)(E), including the maintenance plan requirements under section 175A of the CAA. EPA is also proposing to approve the 2008 baseline emission inventory because EPA believes that it satisfies the requirements of section 172(c)(3). EPA is finding that the 2015 and 2020 NO_X and VOC MVEBs which are included in the maintenance plan are adequate, and EPA is proposing to approve them along with the requested redesignation.

V. What is the effect of EPA's proposed actions?

EPA's proposed actions establish the basis upon which EPA may take final action on the issues being proposed for approval today. Approval of Kentucky's redesignation request would change the legal designation of the Kentucky portion of the tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment area (Boone, Campbell and Kenton Counties) from nonattainment to attainment for the 1997 8-hour ozone NAAQS. 40 CFR part 81. It would also incorporate into the Kentucky SIP a plan for Northern Kentucky to maintain the 1997 8-hour ozone NAAQS in the Area through 2020. This maintenance plan includes contingency measures to remedy future violations of the 1997 8-hour ozone NAAQS. The maintenance plan also includes NO_X and VOC MVEBs for Northern Kentucky, and final approval of the MVEB's would establish them in the approved SIP. Table 1 identifies the state NO_X and VOC MVEBs for the years 2015 and 2020 for Northern Kentucky.

TABLE 1—NORTHERN KENTUCKY 1997 8-HOUR OZONE NO_X AND VOC MVEBS

[Summer season tons per day]

	2015	2020
NO_X	14.40	13.27
VOC	9.76	10.07

Approval of Kentucky's maintenance plan would also result in approval of the NO_X and VOC MVEBs. Additionally, EPA is notifying the public of the status of its adequacy determination for the 2015 and 2020 NO_X and VOC state MVEBs pursuant to 40 CFR 93.118(f)(1). A final approval of EPA's proposed action with respect to the 2008 emissions inventory would also result in approval of that inventory under section 172(c)(3).

VI. What is EPA's analysis of the request?

EPA is proposing to make the determination that the tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment area has attained the 1997 8-hour ozone standard, and that all other redesignation criteria have been met for the Kentucky portion of the tri-state Cincinnati-Hamilton Area. The basis for EPA's determination for the Area is discussed in greater detail below.

Criteria (1)—*The Area has attained the 1997 8-hour ozone NAAQS.*

EPA is proposing to determine that the tri-state Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS. An area may be considered to be attaining the 1997 8-hour ozone NAAQS if as determined in accordance with 40 CFR 50.10 and Appendix I of part 50, it meets the NAAQS based on three complete, consecutive calendar years of quality-assured air quality monitoring data. To attain the standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm. Based on the data handling and reporting convention described in 40 CFR part 50, Appendix I, the standard is attained if the design value is 0.084 ppm or below. The data must be collected and quality-assured in accordance with 40 CFR part 58, and recorded in the EPA Air Quality System (AQS). The monitors generally should have remained at the same location for the duration of the monitoring period required for demonstrating attainment.

EPA reviewed data from the ambient ozone monitoring stations in the tri-state

Cincinnati-Hamilton Area for the ozone seasons from 2007–2009. These data have been quality-assured and certified, and are recorded in AQS. The fourth-highest 8-hour ozone average for 2007, 2008 and 2009, and the 3-year average of these values (*i.e.,* design values), are summarized in the following table:

TABLE 2—ANNUAL 4TH MAX HIGH AND DESIGN VALUE CONCENTRATION FOR 8-HOUR OZONE FOR THE CINCINNATI-HAMILTON OH–KY–IN AREA

[Parts per million]

State*	County	Monitor	2007 4th high (ppm)	2008 4th high (ppm)	2009 4th high (ppm)	2007–2009 average (ppm)
Ohio	Butler	Hamilton, 39–017–0004	0.091	0.071	0.073	0.078
		Middletown, 39–017–1004	0.091	0.079	0.076	0.082
	Clermont	Batavia, 39–025–0022	0.086	0.071	0.069	0.075
	Clinton	Wilmington, 39–027–1022	0.082	0.076	0.070	0.076
	Hamilton	Grooms Rd., Cincinnati, 39–061–0006.	0.089	0.086	0.072	0.082
		Cleves, 39–061–0010	0.086	0.077	0.065	0.076
		250 Wm. Howard Taft, Cincinnati, 39–061–0040.	0.086	0.080	0.074	0.080
	Warren	Lebanon, 39–165–0007	0.088	0.082	0.077	0.082
Kentucky	Boone	KY 338 & Lower River Road, 21–037–3002.	0.078	0.064	0.064	0.068
	Campbell	Highland Heights, 21–117–0007	0.086	0.075	0.068	0.076
	Kenton	Covington, 21–117–0007	0.085	0.073	0.074	0.077

*There is no monitor in the Indiana portion of this Area.

As discussed above, the design value for an area is the highest 3-year average of the annual fourth-highest 8-hour ozone value recorded at any monitor in the Area. Therefore, the most recent 3-year design value (2007–2009) for the tri-state Cincinnati-Hamilton Area is 0.082 ppm, which meets the standard as described above. Currently available data show that the Area continues to attain the NAAQS. If the Area does not continue to attain until EPA finalizes the redesignation, EPA will not go forward with the redesignation. As discussed in more detail below, Kentucky has committed to continue monitoring in this Area in accordance with 40 CFR part 58. EPA proposes to find that the tri-state Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS.

Criteria (2)—*Kentucky has a fully approved SIP under section 110(k) for Northern Kentucky and* Criteria (5)—*Kentucky has met all Applicable Requirements under Section 110 and part D of the CAA.*

Below is a summary of how these two criteria were met.

EPA proposes to find that Kentucky has met all applicable SIP requirements for Northern Kentucky under section 110 of the CAA (general SIP requirements) for purposes of redesignation. EPA also proposes to find that, if EPA finalizes approval of the 2008 emissions inventory submitted with the redesignation request, the Kentucky SIP satisfies the criterion that it meet applicable SIP requirements for purposes of redesignation under part D of title I of the CAA (requirements specific to subpart 1 nonattainment areas) in accordance with section 107(d)(3)(E)(v). In addition, EPA proposes to determine that, upon final approval of the emissions inventory, the SIP is fully approved with respect to all requirements applicable for purposes of redesignation in accordance with section 107(d)(3)(E)(ii). In making these determinations, EPA ascertained which requirements are applicable to the Area and that if applicable, they are fully approved under section 110(k). SIPs must be fully approved only with respect to applicable requirements. As discussed more fully below, SIPs must be fully approved only with respect to requirements that became due prior to the submission of the redesignation request.

a. Northern Kentucky has met all Applicable Requirements under section 110 and part D of the CAA.

The September 4, 1992, Calcagni Memorandum describes EPA's interpretation of section 107(d)(3)(E). Under this interpretation, to qualify for redesignation, states requesting redesignation to attainment must meet only the relevant CAA requirements that come due prior to the submittal of a complete redesignation request. See also Michael Shapiro Memorandum, ("SIP Requirements for Areas Submitting Requests for Redesignation to Attainment of the Ozone and Carbon Monoxide NAAQS On or After November 15, 1992," September 17, 1993); 60 FR 12459, 12465–66 (March 7, 1995) (redesignation of Detroit-Ann Arbor, Michigan). Applicable requirements of the CAA that come due subsequent to the area's submittal of a complete redesignation request remain applicable until a redesignation is approved, but are not required as a prerequisite to redesignation. *See* section 175A(c) of the CAA; *Sierra Club,* 375 F.3d 537; *see also* 68 FR 25424, 25427 (May 12, 2003) (redesignation of St. Louis, Missouri).

If EPA's proposed determination of attainment for the tri-state Cincinnati-Hamilton Area is finalized, under 40 CFR 51.918, if that determination is finalized, the requirements to submit certain planning SIPs related to attainment, including attainment demonstration requirements (the RACM requirement of section 172(c)(1) of the CAA, the RFP and attainment demonstration requirements of sections 172(c)(2) and (c)(6) of the CAA, and the requirement for contingency measures of section 172(c)(9) of the CAA) would not be applicable to the Area so long as it continues to attain the NAAQS and would cease to apply upon redesignation. In addition, in the context of redesignations, EPA has interpreted requirements related to attainment as not applicable for purposes of redesignations. For example, in the General Preamble, EPA stated that:

> [t]he section 172(c)(9) requirements are directed at ensuring RFP and attainment by the applicable date. These requirements no longer apply to an area that has attained the standard and is eligible for redesignation. Furthermore, section 175A for maintenance plans * * * provides specific requirements for contingency measures that effectively supersede the requirements of section

172(c)(9) for these areas. "General Preamble for the Interpretation of Title I of the Clean Air Act Amendments of 1990" ("General Preamble"), 57 FR 13498, 13564 (April 16, 1992).

See also Calcagni Memorandum at page 6 ("The requirements for reasonable further progress and other measures for attainment will not apply for redesignations because they only have meaning for areas not attaining the standard").

General SIP requirements. Section 110(a)(2) of title I of the CAA delineates the general requirements for a SIP, which include enforceable emissions limitations and other control measures, means, or techniques, provisions for the establishment and operation of appropriate devices necessary to collect data on ambient air quality, and programs to enforce the limitations. General SIP elements and requirements are delineated in section 110(a)(2) of title I, part A of the CAA. These requirements include, but are not limited to, the following: submittal of a SIP that has been adopted by the state after reasonable public notice and hearing; provisions for establishment and operation of appropriate procedures needed to monitor ambient air quality; implementation of a source permit program; provisions for the implementation of part C requirements (Prevention of Significant Deterioration (PSD)) and provisions for the implementation of part D requirements (NSR permit programs); provisions for air pollution modeling; and provisions for public and local agency participation in planning and emission control rule development.

Section 110(a)(2)(D) requires that SIPs contain certain measures to prevent sources in a state from significantly contributing to air quality problems in another state. To implement this provision, EPA has required certain states to establish programs to address the transport of air pollutants (NO_X SIP Call [1] and Clean Air Interstate Rule (CAIR) (70 FR 25162, May 12, 2005)). However, the section 110(a)(2)(D) requirements for a state are not linked with a particular nonattainment area's designation and classification in that state. EPA believes that the requirements linked with a particular nonattainment area's designation and classifications are the relevant measures to evaluate in reviewing a redesignation request. The transport SIP submittal requirements, where applicable, continue to apply to a state regardless of the designation of any one particular area in the state. Thus, we do not believe that the CAA's interstate transport requirements should be construed to be applicable requirements for purposes of redesignation.

In addition, EPA believes that the other section 110 elements not connected with nonattainment plan submissions and not linked with an area's attainment status are not applicable requirements for purposes of redesignation. A state remains subject to these requirements after an area is redesignated to attainment. The section 110 and part D requirements, which are linked with a particular area's designation and classification, are the relevant measures to evaluate in reviewing a redesignation request. This approach is consistent with EPA's existing policy on applicability (*i.e.,* for redesignations) of conformity and oxygenated fuels requirements, as well as with section 184 ozone transport requirements. See Reading, Pennsylvania, proposed and final rulemakings (61 FR 53174–53176, October 10, 1996), (62 FR 24826, May 7, 1997); Cleveland-Akron-Loraine, Ohio, final rulemaking (61 FR 20458, May 7, 1996); and Tampa, Florida, final rulemaking at (60 FR 62748, December 7, 1995). See also the discussion on this issue in the Cincinnati, Ohio redesignation (65 FR 37890, June 19, 2000), and in the Pittsburgh, Pennsylvania redesignation (66 FR 50399, October 19, 2001).

EPA believes that section 110 elements not linked to the Area's nonattainment status are not applicable for purposes of redesignation. Therefore, as was discussed above, for purposes of redesignation, they are not considered applicable requirements. Nonetheless, EPA notes it has previously approved provisions in the Kentucky SIP addressing section 110 elements under the 1-hour ozone NAAQS (65 FR 37879, June 19, 2000) The Commonwealth believes that the section 110 SIP approved for the 1-hour ozone NAAQS are sufficient to meet the requirements under the 1997 8-hour ozone NAAQS. The Commonwealth has submitted a letter dated December 10, 2007, setting forth its belief that the section 110 SIP approved for the 1-hour ozone NAAQS is also sufficient to meet the requirements under the 1997 8-hour ozone NAAQS. EPA has not yet approved this submission, but such approval is not necessary for purposes of redesignation.

Part D requirements. EPA proposes that if EPA approves the Commonwealth's base year emissions inventory, which is part of the maintenance plan submittal, the Kentucky SIP will meet applicable SIP requirements under part D of the CAA. We believe the emissions inventory is approvable because the 2008 VOC and NO_X emissions for Northern Kentucky were developed consistent with EPA guidance for emission inventories and the choice of the 2008 base year is appropriate because it represents the 2007–2009 period when the 1997 8 hour ozone NAAQS was not violated.

Part D, subpart 1 applicable SIP requirements. EPA has determined that, if EPA finalizes the approval of the base year emissions inventories discussed in section IX. of this rulemaking, the Kentucky SIP will meet the applicable SIP requirements for their portions of the tri-state Cincinnati-Hamilton Area applicable for purposes of redesignation under part D of the CAA. Subpart 1 of part D, found in sections 172–176 of the CAA, sets for the basic nonattainment requirements applicable to all nonattainment areas. Subpart 2 of part D, which includes section 182 of the CAA, establishes additional specific requirements depending on the area's nonattainment classification. Since the tri-state Cincinnati-Hamilton Area (of which Northern Kentucky is a part) was not classified under subpart 2 at the time the redesignation request was submitted, the subpart 2 requirements do not apply for purposes of evaluating the Commonwealth's redesignation request. The applicable subpart 1 requirements are contained in sections 172(c)(1)–(9) and in section 176.

For purposes of evaluating this redesignation request, the applicable part D, subpart 1 SIP requirements for all nonattainment areas are contained in sections 172–176. A thorough discussion of the requirements contained in section 172 can be found in the General Preamble for Implementation of title I (57 FR 13498).

Subpart 1 Section 172 Requirements. For purposes of evaluating this redesignation request, the applicable section 172 SIP requirements for the tri-state Cincinnati-Hamilton area are contained in sections 172(c)(1)–(9). A thorough discussion of the requirements contained in section 172 can be found in the General Preamble for Implementation of Title I (57 FR 13498, April 16, 1992).

Section 172(c)(1) requires the plans for all nonattainment areas to provide

[1] On October 27, 1998 (63 FR 57356), EPA issued a NO_X SIP Call requiring the District of Columbia and 22 states to reduce emissions of NO_X in order to reduce the transport of ozone and ozone precursors. In compliance with EPA's NO_X SIP Call, Kentucky has developed rules governing the control of NO_X emissions from Electric Generating Units (EGUs), major non-EGU industrial boilers, major cement kilns, and internal combustion engines. EPA approved Kentucky's rules as fulfilling Phase I and Phase II of the NO_X SIP Call on October 23, 2009 (74 FR 54755).

for the implementation of all RACM as expeditiously as practicable and to provide for attainment of the national primary ambient air quality standards. EPA interprets this requirement to impose a duty on all nonattainment areas to consider all available control measures and to adopt and implement such measures as are reasonably available for implementation in each area as components of the area's attainment demonstration. On December 7, 2007, the Commonwealth submitted an attainment demonstration and identified the control measures necessary to attain the NAAQS in the tri-state Cincinnati-Hamilton Area. Similar attainment demonstrations were submitted by Ohio and Indiana as part of the tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment Area. However, because attainment has been reached, no additional measures are needed to provide for attainment, and section 172(c)(1) requirements are no longer considered to be applicable as long as the area continues to attain the standard until redesignation. 40 CFR 51.918. If EPA finalizes approval of the redesignation of the Kentucky portion of the tri-state Cincinnati-Hamilton Area, EPA will take no further action on the attainment demonstration submitted by the Commonwealth of Kentucky for this Area.

The RFP requirement under section 172(c)(2) is defined as progress that must be made toward attainment. This requirement is not relevant for purposes of redesignation because the tri-state Cincinnati-Hamilton Area has monitored attainment of the ozone NAAQS. (General Preamble, 57 FR 13564). *See also* 40 CFR 51.918. In addition, because the tri-state Cincinnati-Hamilton Area has attained the ozone NAAQS and is no longer subject to an RFP requirement, the requirement to submit the section 172(c)(9) contingency measures is not applicable for purposes of redesignation. *Id.*

Section 172(c)(3) requires submission and approval of a comprehensive, accurate and current inventory of actual emissions. As part of Kentucky's redesignation request for the tri-state Cincinnati-Hamilton Area, the Commonwealth submitted a 2008 base year emissions inventory. As discussed below in section IX., EPA is proposing to approve the 2008 base year inventory that Kentucky submitted with the redesignation request as meeting the section 172(c)(3) emissions inventory requirement.

Section 172(c)(4) requires the identification and quantification of allowable emissions for major new and modified stationary sources to be allowed in an area, and section 172(c)(5) requires source permits for the construction and operation of new and modified major stationary sources anywhere in the nonattainment area. EPA has determined that, since PSD requirements will apply after redesignation, areas being redesignated need not comply with the requirement that a NSR program be approved prior to redesignation, provided that the Area demonstrates maintenance of the NAAQS without part D NSR. A more detailed rationale for this view is described in a memorandum from Mary Nichols, Assistant Administrator for Air and Radiation, dated October 14, 1994, entitled, "Part D New Source Review Requirements for Areas Requesting Redesignation to Attainment." Kentucky has demonstrated that the tri-state Cincinnati-Hamilton Area will be able to maintain the standard without part D NSR in effect; therefore, EPA concludes that the Commonwealth need not have fully approved part D NSR programs prior to approval of the redesignation request. The Commonwealth's PSD programs will become effective in the tri-state Cincinnati-Hamilton Area upon redesignation to attainment. *See* rulemakings for Detroit, Michigan (60 FR 12467–12468, March 7, 1995); Cleveland-Akron-Lorain, Ohio (61 FR 20458, 20469–20470, May 7, 1996); Louisville, Kentucky (66 FR 53665, October 23, 2001); and Grand Rapids, Michigan (61 FR 31834–31837, June 21, 1996).

Section 172(c)(6) requires the SIP to contain control measures necessary to provide for attainment of the standard. Because attainment has been reached, no additional measures are needed to provide for attainment.

Section 172(c)(7) requires the SIP to meet the applicable provisions of section 110(a)(2). As noted above, we believe the Kentucky SIP meets the requirements of section 110(a)(2) applicable for purposes of redesignation.

Section 176 Conformity Requirements. Section 176(c) of the CAA requires states to establish criteria and procedures to ensure that federally-supported or funded projects conform to the air quality planning goals in the applicable SIP. The requirement to determine conformity applies to transportation plans, programs and projects developed, funded or approved under title 23 of the United States Code (U.S.C.) and the Federal Transit Act (transportation conformity) as well as to all other federally supported or funded projects (general conformity). State transportation conformity SIP revisions must be consistent with Federal conformity regulations relating to consultation, enforcement and enforceability that EPA promulgated pursuant to its authority under the CAA.

EPA believes it is reasonable to interpret the conformity SIP requirements [2] as not applying for purposes of evaluating the redesignation request under section 107(d) because state conformity rules are still required after redesignation and Federal conformity rules apply where state rules have not been approved. *See Wall,* 265 F.3d 426 (upholding this interpretation); See also 60 FR 62748 (December 7, 1995, Tampa, Florida). Kentucky submitted its transportation conformity SIP for 1997 8-hour ozone and particulate matter NAAQS on December 31, 2008. EPA proposed approval on December 4, 2009 (74 FR 63697) for Kentucky's transportation conformity SIP. EPA did not receive any comments for its proposed approval of Kentucky's transportation conformity SIP and is in the process of finalizing its action for this submission. Kentucky did not have a Federally-approved transportation conformity SIP for the 1-hour NAAQS, and thus approval of Kentucky's December 31, 2008, submittal will establish Kentucky's first Federally-approved transportation conformity SIP. However, conformity analyses are performed pursuant to EPA's Federal conformity rules.

NSR Requirements. EPA has also determined that areas being redesignated need not comply with the requirement that a NSR program be approved prior to redesignation, provided that the area demonstrates maintenance of the standard without a part D NSR program in effect since PSD requirements will apply after redesignation. The rationale for this view is described in a memorandum from Mary Nichols, Assistant Administrator for Air and Radiation, dated October 14, 1994, entitled "Part D New Source Review (Part D NSR) Requirements for Areas Requesting Redesignation to Attainment." Kentucky has demonstrated that Northern Kentucky (as part of the tri-state Cincinnati-Hamilton Area) will be able to maintain the standard without a part D NSR program in effect, and therefore, Kentucky need not have a fully-approved part D NSR program prior to approval of the redesignation request.

[2] CAA Section 176(c)(4)(E) requires states to submit revisions to their SIPs to reflect certain Federal criteria and procedures for determining transportation conformity. Transportation conformity SIPs are different from the motor vehicle emission budgets that are established in control strategy SIPs and maintenance plans.

However, Kentucky currently has a fully-approved part D NSR program in place. Kentucky has a fully-approved part D NSR program. Kentucky's PSD program will become effective in Northern Kentucky upon redesignation to attainment. *See* rulemakings for Detroit, Michigan (60 FR 12467–12468, March 7, 1995); Cleveland-Akron-Lorraine, Ohio (61 FR 20458, 20469–70, May 7, 1996); Louisville, Kentucky (66 FR 53665, October 23, 2001); and Grand Rapids, Michigan (61 FR 31834–31837, June 21, 1996). Thus, Northern Kentucky has satisfied all applicable requirements for purposes of redesignation under section 110 and part D of the CAA.

b. Northern Kentucky has a fully approved applicable SIP under section 110(k) of the CAA.

If EPA issues a final approval of the base year emissions inventories, EPA will have fully approved the applicable Kentucky SIP for the Kentucky portion of the tri-state Cincinnati-Hamilton 8-hour ozone nonattainment area, under section 110(k) of the CAA for all requirements applicable for purposes of redesignation. EPA may rely on prior SIP approvals in approving a redesignation request, see Calcagni Memorandum at p. 3; *Southwestern Pennsylvania Growth Alliance* v. *Browner,* 144 F.3d 984, 989–90 (6th Cir. 1998); *Wall,* 265 F.3d 426, plus any additional measures it may approve in conjunction with a redesignation action. See 68 FR 25426 (May 12, 2003) and citations therein. Following passage of the CAA of 1970, Kentucky has adopted and submitted, and EPA has fully approved at various times, provisions addressing the various 1-hour ozone NAAQS SIP elements applicable in the Cincinnati-Hamilton Area (65 FR 37879, June 19, 2000).

As indicated above, EPA believes that the section 110 elements not connected with nonattainment plan submissions and not linked to the area's nonattainment status are not applicable requirements for purposes of redesignation. EPA also believes that since the part D subpart 2 requirements did not become due prior to submission of the redesignation request, they also are therefore not applicable requirements for purposes of redesignation. *Sierra Club* v. *EPA,* 375 F.3d 537 (7th Cir. 2004); 68 FR 25424, 25427 (May 12, 2003) (redesignation of the St. Louis-East St. Louis Area to attainment of the 1-hour ozone NAAQS). With the approval of the emissions inventory, EPA will have approved all Part D subpart 1 requirements applicable for purposes of redesignation.

Criteria (3)—*The air quality improvement in the tri-state Cincinnati-Hamilton 1997 8-hour Ozone NAAQS Nonattainment Area is due to permanent and enforceable reductions in emissions resulting from implementation of the SIP and applicable Federal air pollution control regulations and other permanent and enforceable reductions.*

Measured reductions in ozone concentrations in and around Northern Kentucky are largely attributable to reductions from emission sources—in Kentucky as well as Ohio and Indiana—of VOC and NO_X, which are precursors in the formation of ozone. See 75 FR 8879. EPA believes that Kentucky has demonstrated that the observed air quality improvement in the tri-state Cincinnati-Hamilton Area is due to permanent and enforceable reductions in emissions resulting from implementation of the SIP, Federal measures, and other state adopted measures. Additionally, new emissions control programs for fuels and motor vehicles will help ensure a continued decrease in emissions throughout the region. The following is a discussion of permanent and enforceable measures that have been implemented in the Northern Kentucky Area.

i. *Stationary Source NO_X Rules.* Kentucky has developed rules governing the control of NO_X emissions from EGUs, major non-EGU industrial boilers, major cement kilns, and internal combustion engines. EPA approved Kentucky's rules as fulfilling Phase I and Phase II of the NO_X SIP Call on October 23, 2009 (74 FR 54755). Kentucky began complying with Phase I of this rule in 2004. Compliance with Phase II of the SIP Call, which requires the control NO_X emissions from large internal combustion engines, began in Kentucky in 2007, and resulted in a 41 percent NO_X reduction from 1995 to 2008 levels.

ii. *Federal Emission Control Measures.* Reductions in VOC and NO_X emissions have occurred statewide and in upwind areas as a result of Federal emission control measures, with additional emission reductions expected to occur in the future. Federal emission control measures include the following.

Tier 2 Emission Standards for Vehicles and Gasoline Sulfur Standards. These emission control requirements result in lower VOC and NO_X emissions from new cars and light duty trucks, including sport utility vehicles. The Federal rules were phased in between 2004 and 2009. EPA has estimated that, by the end of the phase-in period, the following vehicle NO_X emission reductions will occur nationwide: passenger cars (light duty vehicles) (77 percent); light duty trucks, minivans, and sports utility vehicles (86 percent); and, larger sports utility vehicles, vans, and heavier trucks (69 to 95 percent). VOC emission reductions are expected to range from 12 to 18 percent, depending on vehicle class, over the same period. Some of these emission reductions occurred by the attainment years (2007–2009) and additional emission reductions will occur during the maintenance period.

Heavy-Duty Diesel Engine Rule. EPA issued this rule in July 2000. This rule includes standards limiting the sulfur content of diesel fuel, which went into effect in 2004. A second phase took effect in 2007 which further reduced the highway diesel fuel sulfur content to 15 ppm, leading to additional reductions in combustion NO_X and VOC emissions. This rule is expected to achieve a 95 percent reduction in NO_X emissions from diesel trucks and busses.

Non-Road Diesel Rule. EPA issued this rule in 2004. This rule applies to diesel engines used in industries, such as construction, agriculture, and mining. It is estimated that compliance with this rule will cut NO_X emissions from non-road diesel engines by up to 90 percent. This rule is currently achieving emission reductions, but will not be fully implemented until 2010.

iii. *Control Measures in Upwind Areas.* On October 27, 1998 (63 FR 57356), EPA issued a NO_X SIP Call requiring the District of Columbia and 22 states to reduce emissions of NO_X. Affected states were required to comply with Phase I of the SIP Call beginning in 2004, and Phase II beginning in 2007. The reduction in NO_X emissions has resulted in lower concentrations of transported ozone entering the Cincinnati-Hamilton area. Emission reductions resulting from regulations developed in response to the NO_X SIP Call are permanent and enforceable.

Additional measures implemented by the Commonwealth of Kentucky which are providing emission reduction benefits for the Northern Kentucky Area:

- All new major VOC sources locating in Kentucky are subject to RACT;
- All major modifications to existing major VOC sources are subject to RACT requirements;
- Implementation of a program to enhance inspection of stationary sources to ensure emission control equipment is functioning properly;
- Requirements for Stage II vapor recovery;
- Federal Motor Vehicle Control Standards apply in Kentucky;
- Reformulated gasoline;

• Federal controls on VOC content for Architectural and Maintenance Paints, Auto Body Shops, and Consumer Products;

• Open burning ban during summer ozone season for Northern Kentucky; and

• PSD requirements.

In addition to the measures listed above, further reductions will be achieved throughout the implementation of new federal regulations to further control the emission of Hazardous Air Pollutants that are VOC and the emission control programs being imposed as a result of enforcement agreements with some sources in the area. The reductions cannot be quantified at this time, but will be reflected in future triennial assessments.

Regarding point source emissions for the Kentucky portion of the tri-state Cincinnati-Hamilton Area, Duke Power's East Bend plant located in Boone County operates a wet lime scrubber, which controls sulfur dioxide emissions; and a modified furnace designed with low NO_X burners and selective catalytic reduction to reduce NO_X emissions.

Criteria (4)—*The area has a fully approved maintenance plan pursuant to section 175A of the CAA.*

In conjunction with its request to redesignate Northern Kentucky (as part of the tri-state Cincinnati-Hamilton 1997 8-hour ozone nonattainment area) to attainment, Kentucky submitted a SIP revision to provide for the maintenance of the 1997 8-hour ozone NAAQS for at least 10 years after the effective date of redesignation to attainment and commits to submitting a revised 10 year maintenance plan eight years after the redesignation is approved if they are still required to do so at that time.

a. What is required in a maintenance plan?

Section 175A of the CAA sets forth the elements of a maintenance plan for areas seeking redesignation from nonattainment to attainment. Under section 175A, the plan must demonstrate continued attainment of the applicable NAAQS for at least 10 years after the Administrator approves a redesignation to attainment. Eight years after the redesignation, the State of Kentucky must submit a revised maintenance plan, which demonstrates that attainment will continue to be maintained for the 10 years following the initial 10-year period. To address the possibility of future NAAQS violations, the maintenance plan must contain such contingency measures, with a schedule for implementation as EPA deems necessary to assure prompt correction of any future 1997 8-hour ozone violations. Section 175A of the CAA sets forth the requirements for maintenance plans for areas seeking redesignation from nonattainment to attainment. The Calcagni Memorandum provides additional guidance on the content of a maintenance plan. The Calcagni Memorandum explains that an ozone maintenance plan should address five elements: the attainment emissions inventory, maintenance demonstration, monitoring, verification of continued attainment, and a contingency plan. As is discussed more fully below, EPA proposes to find that Kentucky's maintenance plan includes all the necessary components and is approvable as part of the redesignation request.

b. Attainment Emissions Inventory

In coordination with Ohio and Indiana, Kentucky selected 2008 as "the attainment year" for the purposes of demonstrating maintenance of the 1997 8-hour ozone NAAQS. The attainment inventory identifies the level of emissions in the area, which is sufficient to attain the 1997 8-hour ozone standard. Kentucky began development of the attainment inventory by first developing a baseline emissions inventory for Northern Kentucky. The year 2008 was chosen as the base year for developing a comprehensive ozone precursor emissions inventory for which projected emissions could be developed for 2011, 2015, 2018 and 2020. The projected inventory estimates emissions forward to 2020, which meets the 10-year interval required in Section 175A of the CAA. Nonroad mobile emissions were generated using EPA's National Mobile Inventory Model (NMIM), with the following exceptions: recreational motorboat populations and spatial surrogates were updated; emissions estimates were developed for commercial marine vessels, aircraft, and railroads as these three nonroad categories are not included in NMIM. On-road mobile source emissions were calculated using EPA's MOBILE6.2 emission factors model. The 2008 VOC and NO_X emissions, as well as the emissions for other years, for Northern Kentucky were developed consistent with EPA guidance, and are summarized in Tables 3 and 4 in the following subsection.

c. Maintenance Demonstration

The January 29, 2010, redesignation request includes a maintenance plan for Northern Kentucky. The maintenance plan:

(i) Shows maintenance of the 1997 8-hour ozone standard by providing information to support the demonstration that current and future emissions of VOC and NO_X remain at or below attainment year 2008 emissions levels. The year 2008 was chosen as the attainment year because it is one of the years in the most recent three-year period (2007-2009) during which the tri-state Cincinnati-Hamilton Area attained the 1997 8-hour ozone standard. A maintenance demonstration need not be based on modeling. See *Wall* v. *EPA,* 265 F.3d 426 (6th Cir. 2001), *Sierra Club* v. *EPA,* 375 F.3d 537 (7th Cir. 2004). See also 66 FR 53094, 53099–53100 (October 19, 2001), 68 FR 25413, 25430–25432 (May 12, 2003)).

(ii) Uses 2008 as the attainment year and includes future emission inventory projections for 2011, 2015, 2018, and 2020.

(iii) Identifies an "out year," at least 10 years (and beyond) after the time necessary for EPA to review and approve the redesignation request. Per 40 CFR part 93, NO_X and VOC MVEBs were established for the last year (2020) of the maintenance plan. Additionally, Kentucky chose, through interagency consultation, to establish MVEBs for 2015 for NO_X and VOC. See section VII below.

(iv) Provides the following actual and projected emissions inventories, in tons per day (tpd) for Northern Kentucky. See Tables 3 and 4.

TABLE 3—NORTHERN KENTUCKY VOC EMISSIONS

[tpd]

	2008	2011	2015	2018	2020
Point					
Boone	2.81	2.90	3.04	3.14	3.20
Campbell	0.28	0.29	0.30	0.31	0.31
Kenton	1.17	1.23	1.31	1.38	1.42

TABLE 3—NORTHERN KENTUCKY VOC EMISSIONS—Continued

[tpd]

	2008	2011	2015	2018	2020
Point Total	4.79	4.42	4.65	4.62	4.93
Area					
Boone	8.41	8.45	8.50	8.50	8.50
Campbell	4.34	4.28	4.20	4.20	4.20
Kenton	7.88	7.79	7.66	7.66	7.66
Area Total	20.63	20.52	20.36	20.36	20.36
Nonroad					
Boone	5.07	4.84	4.55	4.44	4.36
Campbell	1.51	1.41	1.29	1.25	1.22
Kenton	1.95	1.87	1.76	1.74	1.73
Nonroad Total	8.53	8.12	7.60	7.68	7.31
Mobile*					
Boone	4.00	3.63	3.17	3.04	2.96
Campbell	2.29	2.04	1.74	1.62	1.55
Kenton	3.85	3.39	2.85	2.67	2.56
Mobile Total	10.14	9.06	8.29	7.69	7.07
Northern Kentucky Total	44.09	42.12	40.90	40.35	39.67

* Calculated using MOBILE6.2.

TABLE 4—NORTHERN KENTUCKY NO_X EMISSIONS

[tons per day]

	2008	2011	2015	2018	2020
Point					
Boone	23.27	24.04	25.08	25.91	26.47
Campbell	0.02	0.02	0.02	0.03	0.03
Kenton	0.04	0.03	0.03	0.03	0.03
Point Total	23.33	24.09	25.13	25.97	26.53
Area					
Boone	5.02	5.02	5.03	5.03	5.03
Campbell	1.32	1.31	1.30	1.30	1.30
Kenton	4.06	4.04	4.02	4.02	4.02
Area Total	10.40	10.37	10.35	10.35	10.35
Nonroad					
Boone	11.02	10.47	9.77	9.60	9.48
Campbell	5.34	5.00	4.57	4.43	4.34
Kenton	7.33	6.81	6.15	5.91	5.75
Nonroad Total	23.69	22.28	20.49	19.94	19.57
Mobile*					
Boone	8.53	6.64	4.63	3.90	3.45
Campbell	4.88	3.74	2.54	2.09	1.81
Kenton	8.37	6.33	4.23	3.47	3.01
Mobile Total	21.78	16.71	11.40	9.46	8.27
Northern Kentucky Total	79.20	73.45	67.37	65.72	54.72

* Calculated using MOBILE6.2.

Kentucky is using emissions inventory projections for the years 2011, 2015, 2018 and 2020 to demonstrate maintenance. The Ohio-Kentucky-Indiana (OKI) Regional Council of Governments calculated onroad emissions for 2011, 2015, 2018 and 2020 using the MOBILE6.2 emissions model in addition to using this model to calculate the 2008 base year emissions. Emissions estimates for the remaining source categories were based on future year inventories developed by Kentucky and the Lake Michigan Air Directors Consortium (LADCO). Specifically, for Kentucky's submission, LADCO developed the emissions and projections for area and nonhighway mobile sources. Kentucky used information in the National Emissions Inventory (NEI) database and Kentucky's Emissions Inventory Systems database to determine the point source emissions. A comparison was made between employment projections and earnings projections using the U.S. Department of Commerce's Bureau of Economic Analysis data. Kentucky's submission provides detailed documentation for how the emissions were developed for this submission. EPA has reviewed this information and has determined that the emissions were developed using methodology that is consistent with EPA policy and guidance.

Consideration of CAIR for Maintenance Demonstration. The emission projections show that Ohio, Indiana (75 FR 8882–8884), and Kentucky do not expect emissions in the tri-state Cincinnati-Hamilton Area to exceed the level of the 2008 attainment year inventory during the maintenance period, even without implementation of CAIR (see also discussion below). As shown in Table 5, VOC and NO_X emissions in the entire tri-state Cincinnati-Hamilton Area are projected to decrease by 30.41 tpd and 47.00 tpd, respectively, between 2008 and 2020.

Table 5. Comparison of 2008, 2015 and 2020 VOC and NO_X Emissions for the Entire Tri-State Cincinnati-Hamilton Area (tpd)

	VOC					NOx				
	2008	2015	2020	Net Change (2008-2015)	Net Change (2008-2020)	2008	2015	2020	Net Change (2008-2015)	Net Change (2008-2020)
Point	14.91	17.50	18.46	2.59	3.55	112.29	159.03	163.65	46.74	51.36
Area	78.36	74.69	74.69	-3.67	-3.67	21.38	21.38	21.38	0.00	0.00
Onroad	55.47	35.35	32.13	-20.12	-23.34	113.45	54.01	38.17	-59.44	-75.28
Nonroad	39.04	33.65	32.09	-5.39	-6.95	62.35	45.73	39.27	-16.62	-23.08
Total	187.78	161.19	157.37	-26.59	-30.41	309.47	280.15	262.47	-29.32	-47.00

To further support the maintenance plan demonstrations for the tri-state Cincinnati-Hamilton Area, LADCO performed a regional modeling analysis to address the effect of the recent court decision vacating CAIR. This analysis is documented in LADCO's "Regional Air Quality Analyses for Ozone, $PM_{2.5}$, and Regional Haze: Final Technical Support Document (Supplement), September 12, 2008;" see the discussion in EPA's proposed approval of the Ohio and Indiana maintenance plans for the tri-state Cincinnati-Hamilton Area. See 75 FR 8883–8884.

LADCO produced a base year inventory for 2005 and future year inventories for 2009, 2012, and 2018. To estimate future electric generating units (EGU) NO_X emissions without implementation of CAIR, LADCO projected 2007 EGU NO_X emissions for all states in the modeling domain based on Energy Information Administration growth rates by state (North American Electric Reliability Corporation region) and fuel type for the years 2009, 2012 and 2018. The assumed 2007–2018 growth rates were 8.8 percent for Illinois, Iowa, Missouri and Wisconsin; 13.5 percent for Indiana, Kentucky, Michigan and Ohio; and 15.1 percent for Minnesota. Emissions were adjusted by applying legally enforceable controls, e.g., consent decree or rule.

Ozone modeling performed by LADCO supports the conclusion that the tri-state Cincinnati-Hamilton Area will maintain the standard throughout the maintenance period. Peak modeled ozone levels in the area for 2009, 2012 and 2018 are 0.082 ppm, 0.081 ppm, and 0.078 ppm, respectively. These projected ozone levels were modeled applying only legally enforceable controls; *e.g.,* consent decrees, rules, the NO_X SIP Call, Federal motor vehicle control programs (FMVCP), etc. Because these programs will remain in place, emission levels, and therefore ozone levels, would not be expected to increase significantly between 2018 and 2020.

EPA has considered the relationship of the maintenance plans to the reductions required pursuant to CAIR. CAIR was remanded to EPA, and the process of developing a replacement rule is ongoing. However, the remand of CAIR does not alter the requirements of the NO_X SIP Call, and Kentucky has demonstrated maintenance without any additional CAIR requirements (beyond those required by the NO_X SIP Call). Therefore, EPA believes that Kentucky's demonstration of maintenance under sections 175A and 107(d)(3)(E) is valid.

The NO_X SIP Call requires states to make significant, specific emissions reductions. It also provided a mechanism, the NO_X Budget Trading Program, which states could use to achieve those reductions. When EPA promulgated CAIR, it discontinued (starting in 2009) the NO_X Budget Trading Program, 40 CFR 51.121(r), but created another mechanism, the CAIR ozone season trading program, which states could use to meet their SIP Call obligations, 70 FR 25289–90. EPA notes that a number of states, when submitting SIP revisions to require sources to participate in the CAIR ozone season trading program, removed the SIP provisions that required sources to participate in the NO_X Budget Trading Program. In addition, because the provisions of CAIR, including the ozone season NO_X trading program, remain in place during the remand, EPA is not currently administering the NO_X Budget Trading Program. Nonetheless, all states, regardless of the current status of

their regulations that previously required participation in the NO_X Budget Trading Program, will remain subject to all of the requirements in the NO_X SIP Call even if the existing CAIR ozone season trading program is withdrawn or altered. In addition, the anti-backsliding provisions of 40 CFR 51.905(f) specifically provide that the provisions of the NO_X SIP Call, including the statewide NO_X emission budgets, continue to apply after revocation of the 1-hour standard.

All NO_X SIP Call states have SIPs that currently satisfy their obligations under the SIP Call, the SIP Call reduction requirements are being met, and EPA will continue to enforce the requirements of the NO_X SIP Call even after any response to the CAIR remand. For these reasons, EPA believes that regardless of the status of the CAIR program, the NO_X SIP Call requirements can be relied upon in demonstrating maintenance. Here, Kentucky has demonstrated maintenance based in part on those requirements.

d. Monitoring Network

There are currently eleven monitors measuring ozone in the tri-state Cincinnati-Hamilton Area (three in Northern Kentucky and one in the remainder in the Ohio portion of this Area). Kentucky has committed, in the maintenance plan, to continue operation of the three monitors in Northern Kentucky in compliance with 40 CFR part 58, and has addressed the requirement for monitoring. Ohio has made a similar commitment in their redesignation and maintenance plan submission to EPA for this Area. There is no monitor in the Indiana portion of this Area.

e. Verification of Continued Attainment

The Commonwealth of Kentucky has the legal authority to enforce and implement the requirements of the ozone maintenance plan. This includes the authority to adopt, implement and enforce any subsequent emissions control contingency measures determined to be necessary to correct future ozone attainment problems.

Kentucky will track the progress of the maintenance plan by performing future reviews of emissions inventory for Northern Kentucky using the latest emissions factors, models and methodologies. For these periodic inventories, Kentucky will review the assumptions made for the purpose of the maintenance demonstration concerning projected growth of activity levels. If any of these assumptions appear to have changed substantially, Kentucky commits to re-project emissions.

f. Contingency Plan

The contingency plan provisions are designed to promptly correct a violation of the NAAQS that occurs after redesignation. Section 175A of the CAA requires that a maintenance plan include such contingency measures as EPA deems necessary to assure that the state will promptly correct a violation of the NAAQS that occurs after redesignation. The maintenance plan should identify the contingency measures to be adopted, a schedule and procedure for adoption and implementation, and a time limit for action by the state. A state should also identify specific indicators to be used to determine when the contingency measures need to be implemented. The maintenance plan must include a requirement that a state will implement all measures with respect to control of the pollutant that were contained in the SIP before redesignation of the area to attainment in accordance with section 175A(d).

In the January 29, 2010, submittal, Kentucky affirms that all programs instituted by the Commonwealth and EPA will remain enforceable, and that sources are prohibited from reducing emissions controls following the redesignation of the area. Kentucky commits in their submission to provide an update for the maintenance plan 8 years after formal redesignation in accordance with section 175A(b) of the CAA should this requirement remain applicable for this Area.

As required by section 175A of the CAA, Kentucky has adopted a contingency plan to address possible future 8-hour ozone air quality problems. In the event that a measured value of the fourth highest maximum is 0.085 ppm or greater in any portion of the maintenance area in a single ozone season, or if periodic emissions inventory updates reveal excessive or unanticipated growth greater than ten percent in ozone precursor emissions, the Commonwealth will evaluate existing control measures to see if any further emission reductions should be implemented at that time.

In the event of a monitored violation of the 1997 8-hour ozone NAAQS in the tri-state Cincinnati-Hamilton Area, Kentucky commits to adopt, within nine months, one or more of the following contingency measures to re-attain the standard. A violation of the standard occurs when the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration is equal to or greater than 0.085 ppm. All regulatory programs will be adopted and implemented within 18 months after the triggering monitored violation.

- Implementation of a program to require additional emissions reductions on stationary sources;
- Implementation of fuel programs, including incentives for alternative fuels; Restriction of certain roads or lanes to, or construction of such roads or lands for use by passenger buses or high-occupancy vehicles;
- Trip-reduction ordinances;
- Employer-based transportation management plans, including incentives;
- Programs to limit or restrict vehicle us in downtown areas, or other areas of emissions concentration, particularly during periods of peak use;
- Programs for new construction and major reconstructions of paths or tracks for use by pedestrians or by non-motorized vehicles when economically feasible and in the public interest.

Kentucky also reserves the right in its submission to implement other contingency measures if new control programs should be developed and advantageous for the Area.

EPA believes that that the maintenance plan adequately addresses the five basic components of a maintenance plan: attainment inventory, maintenance demonstration, monitoring network, verification of continued attainment, and a contingency plan. Thus EPA proposes to find that the maintenance plan SIP revision submitted by the Commonwealth of Kentucky for Northern Kentucky meets the requirements of section 175A of the CAA and is approvable.

VII. What is EPA's analysis of Kentucky's proposed state NO_X and VOC MVEBs for Northern Kentucky?

Under the CAA, states are required to submit, at various times, control strategy SIPs and maintenance plans in ozone areas. These control strategy SIPs (RFP and attainment demonstration) and maintenance plans establish MVEBs for criteria pollutants and/or their precursors to address pollution from cars and trucks. Per 40 CFR part 93, an MVEB is established for the last year of the maintenance plan. A state may adopt MVEBs for other years as well. The MVEB is the portion of the total allowable emissions in the maintenance demonstration that is allocated to highway and transit vehicle use and emissions. See 40 CFR 93.101. The MVEB serves as a ceiling on emissions from an area's planned transportation system. The MVEB concept is further

explained in the preamble to the November 24, 1993, transportation conformity rule (58 FR 62188). The preamble also describes how to establish the MVEB in the SIP and how to revise the MVEB.

After interagency consultation with the transportation partners for the tri-state Cincinnati-Hamilton Area, Kentucky has elected to develop MVEBs for VOC and NO_X for Northern Kentucky separate from the remainder of the tri-state Cincinnati-Hamilton Area. MVEBs for the remainder of the tri-state Cincinnati-Hamilton Area is addressed in the Ohio and Indiana submittals. Kentucky is developing these MVEBs for Northern Kentucky, as required, for the last year of its maintenance plan, 2020, an interim year, 2015. The MVEBs for 2015 and 2020 reflect the total on-road emissions for those individual years, plus an allocation from the available NO_X and VOC safety margin for each year. Under 40 CFR 93.101, the term safety margin is the difference between the attainment level (from all sources) and the projected level of emissions (from all sources) in the maintenance plan. The safety margin can be allocated to the transportation sector; however, the total emissions must remain below the attainment level. These MVEBs and allocation from the safety margin were developed in consultation with the transportation partners and were added to account for uncertainties in population growth, changes in model VMT and new emission factor models. For 2015, the safety margin added to the mobile VOC emissions 2 tpd, and the safety margin added to the mobile NO_X emissions is 3 tpd. For 2020, the safety margin added to the mobile VOC emissions is 3 tpd, and the safety margin added to the mobile NO_X emissions is 5 tpd. The resulting NO_X and VOC MVEBs for Northern Kentucky are defined in Table 6 below.

TABLE 6—NORTHERN KENTUCKY 1997 8-HOUR OZONE NO_X AND VOC MVEBS

[Summer season tons per day]

	2015	2020
NO_X	14.40	13.27
VOC	9.76	10.07

As mentioned above, Kentucky has chosen to allocate a portion of the available safety margin to the 2015 and 2020 NO_X and VOC MVEBs. The following tables identify the original NO_X and VOC safety margins that were available in the tri-state Cincinnati Area for the applicable years. It should be noted that the safety margin allocation from above is not reflected in the following table so any further allocation of the available safety margin in the Kentucky portion of this area will be quantified at the time of the allocation should the Commonwealth elect to allocate additional safety margin to the MVEBs in the Northern Kentucky Area. Table 7 and Table 8 below detail the available safety margin for the tri-state Cincinnati-Hamilton Area prior to allocations provided for MVEBs for Northern Kentucky and the remainder of the tri-state Area. Kentucky's has remaining safety margin to allocate. Should Kentucky decide to allocate further safety margin to the MVEB, the Commonwealth will do so through a subsequent SIP revision which will identify the available safety margin for allocation and any additional allocation.

TABLE 7—SAFETY MARGIN FOR VOC FOR TRI-STATE CINCINNATI-HAMILTON AREA

[tons per day]

VOC	2008	2015	2020	Safety margin	Safety margin
				2015	2020
Butler, OH	26.66	23.85	23.64	2.80	3.01
Clermont, OH	15.51	12.94	12.54	2.39	2.77
Clinton, OH	6.83	5.45	5.02	1.38	1.81
Hamilton, OH	69.25	56.80	55.00	12.41	14.21
Warren, OH	18.48	14.92	14.54	3.56	3.94
Dearborn, IN	7.49	6.86	6.96	12.18	12.08
Boone, KY	20.29	19.26	19.02	1.03	1.27
Campbell, KY	8.42	7.53	7.28	0.89	1.14
Kenton, KY	14.85	13.58	13.37	1.27	1.48
Combined Total	187.78	161.19	157.37	37.91	41.71

TABLE 8—SAFETY MARGIN FOR VOC FOR TRI-STATE CINCINNATI-HAMILTON AREA

[tons per day]

NO_X	2008	2015	2020	Safety margin	Safety margin
				2015	2020
Butler, OH	40.52	30.49	27.06	8.50	11.93
Clermont, OH	39.73	59.76	59.12	−31.80	−32.13
Clinton, OH	6.31	3.84	2.97	2.47	3.34
Hamilton, OH	88.37	73.30	65.16	29.41	37.55
Warren, OH	22.26	13.32	10.88	8.94	11.38

TABLE 8—SAFETY MARGIN FOR VOC FOR TRI-STATE CINCINNATI-HAMILTON AREA—Continued

[tons per day]

NO_X	2008	2015	2020	Safety margin	Safety margin
				2015	2020
Dearborn, IN	33.09	32.07	32.56	0.90	0.41
Boone, KY	47.84	44.51	44.43	3.33	3.41
Campbell, KY	11.56	8.43	7.48	3.13	4.08
Kenton, KY	19.79	14.43	12.81	5.36	6.98
Combined Total	309.47	280.15	262.47	30.24	46.95

Through this rulemaking, EPA is proposing to approve the 2015 and 2020 MVEBs for VOC and NO_X for Northern Kentucky because EPA has determined that the Area maintains the 1997 8-hour ozone NAAQS with the emissions at the levels of the budgets. Once the MVEBs for Northern Kentucky (the subject of this rulemaking) are approved or found adequate (whichever is done first), they must be used for future conformity determinations. See section VIII for more information on the status of EPA's adequacy determination for the proposed NO_X and VOC MVEBs for the years 2015 and 2020 for Northern Kentucky.

VIII. What is the status of EPA's adequacy determination for the proposed NO_X and VOC MVEBs for the years 2015 and 2020 for Northern Kentucky?

Under section 176(c) of the CAA, new transportation projects, such as the construction of new highways, must "conform" to (*i.e.,* be consistent with) the part of the state's air quality plan that addresses pollution from cars and trucks. "Conformity" to the SIP means that transportation activities will not cause new air quality violations, worsen existing violations, or delay timely attainment of the NAAQS. If a transportation plan does not "conform," most new projects that would expand the capacity of roadways cannot go forward. Regulations at 40 CFR part 93 set forth EPA policy, criteria, and procedures for demonstrating and assuring conformity of such transportation activities to a SIP. The regional emissions analysis is one, but not the only, requirement for implementing transportation conformity. Transportation conformity is a requirement for nonattainment and maintenance areas. Maintenance areas are areas that were previously nonattainment for a particular NAAQS but have since been redesignated to attainment with a maintenance plan for that NAAQS.

When reviewing submitted "control strategy" SIPs or maintenance plans containing MVEBs, EPA may affirmatively find the MVEB contained therein "adequate" for use in determining transportation conformity. Once EPA affirmatively finds the submitted MVEB is adequate for transportation conformity purposes, that MVEB must be used by state and Federal agencies in determining whether proposed transportation projects "conform" to the SIP as required by section 176(c) of the CAA.

EPA's substantive criteria for determining "adequacy" of an MVEB are set out in 40 CFR 93.118(e)(4). The process for determining "adequacy" consists of three basic steps: Public notification of a SIP submission, a public comment period, and EPA's adequacy finding. This process for determining the adequacy of submitted SIP MVEBs was initially outlined in EPA's May 14, 1999, guidance, "Conformity Guidance on Implementation of March 2, 1999, Conformity Court Decision." This guidance was finalized in the Transportation Conformity Rule Amendments for the "New 8-Hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards and Miscellaneous Revisions for Existing Areas; transportation conformity rule amendments—Response to Court Decision and Additional Rule Change," on July 1, 2004 (69 FR 40004). Additional information on the adequacy process for MVEBs is available in the proposed rule entitled, "Transportation Conformity Rule Amendments: Response to Court Decision and Additional Rule Changes," 68 FR 38974, 38984 (June 30, 2003).

As discussed earlier, Kentucky's maintenance plan submission includes VOC and NO_X state MVEBs for Northern Kentucky for the years 2015 and 2020. EPA reviewed both the VOCs and NO_X state MVEBs through the adequacy process. The Kentucky SIP submission, including the Northern Kentucky VOC and NO_X MVEBs was open for public comment on EPA's adequacy website on February 3, 2010, found at: *http://www.epa.gov/otaq/stateresources/transconf/currsips.htm.* The EPA public comment period on adequacy of the 2015 and 2020 VOC and NO_X state MVEBs for Northern Kentucky closed on March 5, 2010. EPA did not receive any comments on the adequacy of the MVEBs, nor did EPA receive any requests for the SIP submittal. EPA provided a separate adequacy posting for the MVEBs in association with the Ohio and Indiana portions of this Area. The status of the adequacy process for the Ohio and Indiana MVEBs is discussed in EPA's separate action related to those areas (*see* 75 FR 8871, 8886; February 26, 2010).

EPA intends to make its determination on the adequacy of the 2015 and 2020 MVEBs for Northern Kentucky for transportation conformity purposes by completing the adequacy process that was started on February 3, 2010, in coordination with the final rule for this redesignation request and maintenance plan. After EPA finds the 2015 and 2020 MVEBs, adequate or approves them, the new MVEBs for VOC and NO_X must be used, for future transportation conformity determinations. For required regional emissions analysis years that involve the years 2015 through 2019, the applicable budgets for the purposes of conducting transportation conformity will be the new 2015 MVEBs. For required regional emissions analysis years that involve 2020 or beyond, the applicable budgets will be the new 2020 MVEBs for Northern Kentucky. The 2015 and 2020 MVEBs are defined in section VII of this proposed rulemaking.

IX. What is EPA's analysis of the proposed 2008 base year emissions inventory for Northern Kentucky?

As discussed above, section 172(c)(3) of the CAA requires areas to submit a base year emissions inventory. As part of Kentucky's request to redesignate the

Kentucky portion of the tri-state Cincinnati-Hamilton Area, the Commonwealth submitted 2008 base year emissions inventory to meet this requirement. Emissions contained in the submittal cover the general source categories of point sources, area sources, on-road mobile sources, and non-road mobile sources. All emission summaries were accompanied by source-specific descriptions of emission calculation procedures and sources of input data. On-road mobile emissions were prepared by the OKI using the MOBILE6.2 emissions model.

Kentucky's submittal documents 2008 emissions in the Kentucky portion of the tri-state Cincinnati-Hamilton Area in units of tons per summer day. Table 9 below provides a summary of the 2008 summer day emissions of VOC and NO_X for Northern Kentucky.

NORTHERN KENTUCKY 2008 SUMMER DAY EMISSIONS FOR VOC AND NO_X

[Tons per day]

	NO_X	VOC
Boone	23.27	2.81
Campbell	0.02	0.28
Kenton	0.04	1.17
Point Total	23.33	4.79
Boone	5.02	8.41
Campbell	1.32	4.34
Kenton	4.06	7.88
Area Total	10.40	20.63
Boone	11.02	5.07
Campbell	5.34	1.51
Kenton	7.33	1.95
Nonroad Total	23.69	8.53
Boone	8.53	4.00
Campbell	4.88	2.29
Kenton	8.37	3.85
Mobile Total	21.78	10.14
Northern Kentucky Total	79.20	44.09

EPA is proposing to approve this 2008 base year inventory as meeting the section 172(c)(3) emissions inventory requirement.

X. What are EPA's proposed actions?

EPA is proposing to: (1) To determine that the tri-state Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS based on quality assured monitoring data from 2007–2009; (2) approve Kentucky's redesignation request for Boone, Campbell and Kenton Counties in Kentucky as part of the tri-state Cincinnati Area; (3) approve Kentucky's January 29, 2010 SIP revision providing the 1997 8-hour ozone maintenance plan for Northern Kentucky, including the MVEBs for NO_X and VOC for the years 2015 and 2020; and (4) approve the 2008 emissions inventory for Northern Kentucky as meeting the requirements of the CAA.

EPA's proposed approval is based on the Commonwealth's demonstration that the plan meets the requirements of section 175A of the CAA. After evaluating the Commonwealth's redesignation request, EPA believes that, upon final approval of the emissions inventory that was also submitted, the request meets the redesignation criteria set forth in CAA sections 107(d)(3)(E) and 175A. Therefore, EPA is proposing to approve the redesignation of the Kentucky portion of the tri-state Cincinnati-Hamilton Area from nonattainment to attainment for the 1997 8-hour ozone NAAQS. The final approval of this redesignation request would change the official designation for the Kentucky portion of the tri-state Cincinnati-Hamilton Area from nonattainment to attainment for the 1997 8-hour ozone NAAQS. Final approval would also establish 2015 and 2020 NO_X and VOC MVEBs for Northern Kentucky to use for the purposed of implementing transportation conformity. EPA is proposing to approve Kentucky's 2008 base year emissions inventory for the Kentucky portion of the tri-state Cincinnati-Hamilton Area as meeting the requirements of section 172(c)(3) EPA is taking action on the redesignation requests, emission inventories and maintenance plans for the Ohio and Indiana portions (as a part of the tri-state Cincinnati-Hamilton Area) in a separate but coordinated action.

In this action, EPA is also describing the status of EPA's adequacy determination for the new 2015 and 2020 MVEBs that are contained in the 1997 8-hour ozone maintenance plan for Northern Kentucky in accordance with 40 CFR 93.118(f)(1). Within 24 months from the effective date of EPA's adequacy finding for the MVEBs, or the effective date for the final rule for this action, whichever is earlier, the transportation partners will need to demonstrate conformity to the new NO_X and VOC MVEBs pursuant to 40 CFR 93.104(e). EPA intents to conclude it adequacy process for the Northern Kentucky MVEBs with its final rulemaking for this proposed action. MVEBs for the Ohio and Indiana portions of this Area are included in the Ohio and Indiana submittals, and are being addressed through EPA's separate action for those submissions.

XI. Statutory and Executive Order Reviews

Under the CAA, redesignation of an area to attainment and the accompanying approval of a maintenance plan under section 107(d)(3)(E) are actions that affect the status of a geographical area and do not impose any additional regulatory requirements on sources beyond those imposed by state law. A redesignation to attainment does not in and of itself

create any new requirements, but rather results in the applicability of requirements contained in the CAA for areas that have been redesignated to attainment. Moreover, under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, these proposed actions merely approve state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For these reasons, these proposed actions:

- Are not a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Do not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Are certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Do not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Do not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Are not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Are not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Are not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Do not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects

40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Incorporation by reference, Nitrogen oxides, Ozone, Reporting and recordkeeping requirements, and Volatile organic compounds.

40 CFR Part 81

Environmental protection, Air pollution control, National parks, Wilderness areas.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: May 3, 2010.

A. Stanley Meiburg,

Acting Regional Administrator, Region 4.

[FR Doc. 2010–11145 Filed 5–11–10; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 64

[CG Docket No. 03–123; DA 10–761]

Telecommunications Relay Services and Speech-to-Speech Services for Individuals With Hearing and Speech Disabilities

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: In this document, the Commission, via the Consumer and Governmental Affairs Bureau (Bureau), seeks comment on the annual payment formulas and funding requirement estimates for the Interstate Telecommunications Relay Services (TRS) Fund (Fund) for the period of July 1, 2010, through June 30, 2011 (2010–2011 Fund year), as proposed by the National Exchange Carrier Association (NECA), the Fund Administrator. The Bureau seeks comment on NECA's proposed compensation rates for Interstate TRS, Speech-to-Speech Services (STS), Captioned Telephone Services (CTS), Internet Protocol (IP) CTS, IP Relay, and Video Relay Services (VRS), for the 2010–2011 Fund year, as well as on NECA's proposals for the carrier contribution factor and funding requirement.

DATES: Comments are due on or before May 14, 2010; reply comments are due on or before May 21, 2010.

ADDRESSES: You may submit comments, identified by CG Docket No. 03–123, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Federal Communications Commission's Web Site: http://fjallfoss.fcc.gov/ecfs2/*. Follow the instructions for submitting comments.
- *People with Disabilities:* Contact the FCC to request reasonable accommodations (accessible format documents, sign language interpreters, CART, etc.) by e-mail: *FCC504@fcc.gov* or phone: 202–418–0530 or TTY: 202–418–0432.

For detailed instructions for submitting comments and additional information on the rulemaking process, *see* the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: Diane Mason, Consumer and Governmental Affairs Bureau, Disability Rights Office, at (202) 418–7126 (voice), (202) 418–7828 (TTY), or e-mail at *Diane.Mason@fcc.gov*.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's document DA 10–761, adopted and released on April 30, 2010. The complete text of DA 10–761, NECA's submission and any subsequently filed documents in this matter will be available during regular business hours at the FCC Reference Center, Portals II, 445 12th Street, SW., Room CY–A257, Washington, DC 20554, (202) 418–0270. Document DA 10–761, NECA's submission and any subsequently filed documents in this matter may also be purchased from the Commission's duplicating contractor at its Web site, *http://www.bcpiweb.com,* or call 1–800–378–3160. A copy of the submission may also be found by searching on ECFS (insert CG Docket No. 03–123 into the Proceeding block).

Pursuant to 47 CFR 1.415 and 1.419, interested parties may file comments on this document. All filings must reference CG Docket No. 03–123. Comments may be filed using: (1) The Commission's Electronic Comment Filing System (ECFS), (2) the Federal Government's eRulemaking Portal, or (3) by filing paper copies. Comments may be filed electronically using the Internet by accessing the ECFS: *http://fjallfoss.fcc.gov/ecfs* or the Federal eRulemaking Portal: *http://www.regulations.gov*. Filers should follow the instructions provided on the Web site for submitting comments. In completing the transmittal screen, commenters should include their full name, U.S. Postal Service mailing address, and CG Docket No. 03–123.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, 72, 78, and 97

[EPA–HQ–OAR–2009–0491; FRL–9174–9]

RIN 2060–AP50

Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to limit the interstate transport of emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2). In this action, EPA is proposing to both identify and limit emissions within 32 states in the eastern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS. EPA is proposing to limit these emissions through Federal Implementation Plans (FIPs) that regulate electric generating units (EGUs) in the 32 states. This action will substantially reduce the impact of transported emissions on downwind states. In conjunction with other federal and state actions, it helps assure that all but a handful of areas in the eastern part of the country will be in compliance with the current ozone and $PM_{2.5}$ NAAQS by 2014 or earlier. To the extent the proposed FIPs do not fully address all significant transport, EPA is committed to assuring that any additional reductions needed are addressed quickly. EPA takes comments on ways this proposal could achieve additional NO_X reductions and additional actions including other rulemakings that EPA could undertake to achieve any additional reductions needed.

DATES: *Comments.* Comments must be received on or before October 1, 2010.

Public Hearing: Three public hearings will be held before the end of the comment period. The dates, times and locations will be announced separately. Please refer to **SUPPLEMENTARY INFORMATION** for additional information on the comment period and the public hearings.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2009–0491 by one of the following methods:

- *http://www.regulations.gov.* Follow the online instructions for submitting comments. Attention Docket ID No. EPA–HQ–OAR–2009–0491.
- *E-mail: a-and-r-docket@epa.gov.* Attention Docket ID No. EPA–HQ–OAR–2009–0491.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2009–0491.
- *Mail:* EPA Docket Center, EPA West (Air Docket), Attention Docket ID No. EPA–HQ–OAR–2009–0491, U.S. Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. Please include 2 copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.
- *Hand Delivery:* U.S. Environmental Protection Agency, EPA West (Air Docket), 1301 Constitution Avenue, Northwest, Room 3334, Washington, DC 20004, Attention Docket ID No. EPA–HQ–OAR–2009–0491. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2009–0491. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, avoid any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket and Information Center, EPA/DC, EPA West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Tim Smith, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539–04), Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–4718; fax number: (919) 541–0824; e-mail address: *smith.tim@epa.gov.* For legal questions, please contact Ms. Sonja Rodman, U.S. EPA, Office of General Counsel, Mail Code 2344A, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, telephone (202) 564–4079; e-mail address *rodman.sonja@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

ARP Acid Rain Program
BART Best Available Retrofit Technology
BACT Best Available Control Technology
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CFR Code of Federal Regulations
EGU Electric Generating Unit
FERC Federal Energy Regulatory Commission
FGD Flue Gas Desulfurization
FIP Federal Implementation Plan
FR Federal Register
EPA U.S. Environmental Protection Agency
GHG Greenhouse Gas
Hg Mercury
IPM Integrated Planning Model
lb/mmbtu Pounds Per Million British Thermal Unit
$\mu g/m^3$ Micrograms Per Cubic Meter

NAAQS National Ambient Air Quality Standards
NO_X Nitrogen Oxides
NSPS New Source Performance Standard
OTAG Ozone Transport Assessment Group
PUC Public Utility Commission
SNCR Selective Non-catalytic Reduction
SCR Selective Catalytic Reduction
SIP State Implementation Plan
$PM_{2.5}$ Fine Particulate Matter, Less Than 2.5 Micrometers
PM_{10} Fine and Coarse Particulate Matter, Less Than 10 Micrometers
PM Particulate Matter
RIA Regulatory Impact Analysis
SO_2 Sulfur Dioxide
SO_X Sulfur Oxides, Including Sulfur Dioxide (SO_2) and Sulfur Trioxide (SO_3)
TIP Tribal Implementation Plan tpy Tons Per Year
TSD Technical Support Document

II. General Information

A. Does this action apply to me?

This rule affects EGUs, and regulates the following groups:

Industry group	NAICS [a]
Utilities (electric, natural gas, other systems).	2211, 2212, 2213

[a] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is aware of that could potentially be regulated. Other types of entities not listed in the table could also be regulated. To determine whether your facility would be regulated by the proposed rule, you should carefully examine the applicability criteria in proposed §§ 97.404, 97.504, 97,604, and 97.704.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this proposal will also be available on the World Wide Web. Following signature by the EPA Administrator, a copy of this action will be posted on the transport rule Web site *http://www.epa.gov/airtransport*.

C. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through *http://www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2009–0491.

2. *Tips for preparing your comments.* When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).
- Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.
- Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.
- Describe any assumptions and provide any technical information and/or data that you used.
- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns, and suggest alternatives.
- Explain your views as clearly as possible, avoiding the use of profanity or personal threats.
- Make sure to submit your comments by the comment period deadline identified.

D. How can I find information about the public hearings?

The EPA will hold three public hearings on this proposal. The dates, times and locations of the pubic hearings will be announced separately. Oral testimony will be limited to 5 minutes per commenter. The EPA encourages commenters to provide written versions of their oral testimonies either electronically or in paper copy. Verbatim transcripts and written statements will be included in the rulemaking docket. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela S. Long, Air Quality Policy Division (C504–03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–0641; e-mail: *long.pam@epa.gov*. Persons interested in presenting oral testimony should notify Ms. Long at least 2 days in advance of the public hearings. For updates and additional information on the public hearings, please check EPA's website for this rulemaking, *http://www.epa.gov/airtransport*. The public hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. The EPA officials may ask clarifying questions during the oral presentations, but will not respond to the presentations or comments at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearings.

E. How is this Preamble Organized?

III. Summary of Proposed Rule and Background

A. Summary of Proposed Rule

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any primary or secondary NAAQS. In this notice, EPA proposes to find that emissions of SO_2 and NO_X in 32 eastern states contribute significantly to nonattainment or interfere with maintenance in one or more downwind states with respect to one or more of three air quality standards—the annual average $PM_{2.5}$ NAAQS promulgated in 1997, the 24-hour average $PM_{2.5}$ NAAQS promulgated in 2006, and the ozone NAAQS promulgated in 1997.[1] These emissions are transported downwind either as SO_2 and NO_X or, after transformation in the atmosphere, as fine particles or ozone. This notice identifies emission reduction responsibilities of upwind states, and also proposes enforceable FIPs to achieve the required emissions reductions in each state through cost-effective and flexible requirements for power plants. Each state will have the option of replacing these Federal rules with state rules to achieve the required amount of emissions reductions from sources selected by the state.

With respect to the annual average $PM_{2.5}$ NAAQS, this proposal finds that 24 eastern states have SO_2 and NO_X emission reduction responsibilities, and quantifies each state's full emission reduction responsibility under section 110(a)(2)(D)(i)(I). With respect to the 24-hour average $PM_{2.5}$ NAAQS, this proposal finds that 25 eastern states have emission reduction responsibilities. The proposed reductions will at least partly eliminate, and subject to further analysis may fully eliminate, these states' significant contribution and interference with maintenance for purposes of the 24-hour average $PM_{2.5}$ standard. In all, emissions reductions related to interstate transport

[1] In the context of the jurisdictions covered by this proposed rule, EPA uses the term "states" to include the District of Columbia.

of fine particles would be required in 28 states.

With respect to the 1997 ozone NAAQS, this proposal requires emissions reductions in 26 states. For 16 of these states, we propose that the required reductions represent their full significant contribution and interference with maintenance for the ozone NAAQS. For an additional 10 states, the required NO_X reductions are needed for these states to make measurable progress towards eliminating their significant contribution and interference with maintenance. EPA has begun to conduct additional information gathering and analysis to determine the extent to which further reductions from these states may be needed to fully eliminate significant contribution and interference with maintenance with the 1997 ozone NAAQS.

This proposed rule would achieve substantial near-term emissions reductions from the power sector. EPA projects that with the proposed rule, EGU SO_2 emissions would be 5.0 million tons lower, annual NO_X emissions would be 700,000 tons lower, and ozone season NO_X emissions would be 100,000 tons lower in 2012, compared to baseline 2012 projections in the proposed covered states. Further, EGU SO_2 emissions would be 4.6 million tons lower, annual NO_X emissions would be 700,000 tons lower, and ozone season NO_X emissions would be 100,000 tons lower in 2014, compared to baseline 2014 projections (which will have dropped from 2012 due to other federal and state requirements, thereby lowering the 2014 baseline). *See* Table III.A–2 for projected EGU emissions with the proposed rule compared to baseline, and Table III.A–3 for projected EGU emissions with the proposed rule compared to 2005 actual emissions. The reductions obtained through the Transport Rule FIPs will help all but a very few areas in the eastern part of the country come into attainment with the 1997 $PM_{2.5}$ and ozone standards and take major strides toward helping states address nonattainment with the 2006 24-hour average $PM_{2.5}$ standard. *See* Table III.A–1 for proposed list of covered states.

EPA is committed to fulfilling its responsibility to ensure that downwind states receive the relief from upwind emissions guaranteed under CAA section 110(a)(2)(D) For the 24-hour $PM_{2.5}$ standard, EPA's air quality modeling shows that in the areas with continuing non-attainment or maintenance problems, the remaining exceedances occur almost entirely in the winter months. The relative importance of particle species such as sulfate and nitrate, is quite different between summer and winter. EPA is moving ahead before the final rule is published to determine the extent to which this wintertime problem is caused by emissions transported from upwind states. Further study of the 24-hour $PM_{2.5}$ results could lead to a number of possible outcomes; EPA cannot judge the relative likelihood of these outcomes at this time. To the extent possible, EPA plans to finalize this rule with a full determination of, and remedy for, significant contribution and interference with maintenance for the 24-hour $PM_{2.5}$ standard. To that end, EPA is expeditiously proceeding with examination of the residual wintertime problem. (See full discussion in section IV.D.)

In the case of ozone, EPA must determine whether further NO_X reductions are warranted in certain upwind states that affect two or three areas with relatively persistent ozone air quality problems. To support a full significant contribution determination for these states, EPA is expeditiously conducting further analysis of NO_X control costs, emissions reductions, air quality impacts, and the nature of the residual air quality issues. EPA's current information indicates that considering NO_X reductions beyond the cost per ton levels proposed in this rule will require analysis of reductions from source categories other than EGUs, as well as from EGUs. EPA believes that developing supplemental information to consider NO_X sources beyond EGUs would substantially delay publication of a final rule beyond the anticipated publication of spring 2011. EPA does not believe that this effort should delay the reductions and large health benefits associated with this proposed rule. Thus, EPA intends to proceed with additional rulemaking to address fully the residual significant contribution to nonattainment and interference with maintenance with the ozone standard as quickly as possible. (See full discussion in section IV.D.)

This proposed rule is the first of several EPA rules to be issued over the next 2 years that will yield substantial health and environmental benefits for the public through regulation of power plants. Fossil-fuel-fired power plants contribute a large and substantial fraction of the emissions of several key air pollutants, and the agency has statutory or judicial obligations to make several regulatory determinations on power plant emissions. The Administrator in January established improved air quality as an Agency priority and announced plans to promote a cleaner and more efficient power sector and have strong but achievable reduction goals for SO_2, NO_X, mercury, and other air toxics."

In addition to this rule, other anticipated actions include a section 112(d) rule for electric utilities to be proposed by March 2011, potential rules to address pollution transport under revised NAAQS, revisions to new source performance standards for coal and oil-fired utility electric generating units, and best available retrofit technology (BART) and regional haze program requirements to protect visibility. These actions, and their relationship to this rule, are discussed further in section III.E.

Ongoing reviews of the ozone and $PM_{2.5}$ NAAQS could result in revised NAAQS. To address any new NAAQS, EPA would propose interstate transport determinations in future notices. Such proposals could require greater emissions reductions from states covered by this proposal and/or require reductions from states not covered by this proposal. In addition, while this action proposes to require reductions from the power sector only, it is possible that reductions from other source categories could be needed to address interstate transport requirements related to any new NAAQS.

With this proposal, EPA is also responding to the remand of the CAIR by the Court in 2008. CAIR, promulgated May 12, 2005 (70 FR 25162) requires 28 states and the District of Columbia to adopt and submit revisions to their State Implementation Plans (SIPs) to eliminate SO_2 and NO_X emissions that contribute significantly to downwind nonattainment of the $PM_{2.5}$ and ozone NAAQS promulgated in July 1997. The CAIR FIPs, promulgated April 26, 2006 (71 FR 25328), regulate EGUs in the covered states and achieve the emissions reductions requirements established by CAIR until states have approved SIPs to achieve the reductions. In July 2008, the DC Circuit Court found CAIR and the CAIR FIPs unlawful. *North Carolina* v. *EPA*, 531 F.3d 896 (DC Cir. 2008). The Court's original decision vacated CAIR. *Id.* at 929–30. However, the Court subsequently remanded CAIR to EPA without vacatur because it found that "allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR." *North Carolina* v. *EPA*, 550 F.3d 1176, 1178 (DC Cir. 2008). The CAIR requirements are correctly in place and the CAIR's regional control programs are operating

while EPA develops replacement rules in response to the remand.

As described more fully in the remainder of this preamble, the approaches used in this proposed rule to measure and address each state's significant contribution to downwind nonattainment and interference with maintenance are guided by and consistent with the Court's opinion in *North Carolina* v. *EPA* and address the flaws in CAIR identified by the Court therein. Among other things, the proposal relies on detailed, bottom-up scientific and technical analyses, introduces a state-specific methodology for identifying significant contribution to nonattainment and interference with maintenance, and proposes remedy options to ensure that all necessary reductions are achieved in the covered states.

In this action, EPA proposes to both identify and address emissions within states in the eastern United States that significantly contribute to nonattainment or interfere with maintenance by other downwind states. As discussed in sections III and VII in this preamble and described in greater detail in two separate **Federal Register** notices published on April 25, 2005 (70 FR 21147) and June 9, 2010 (75 FR 32673), EPA has determined, or proposed to determine, that the 32 states covered by this proposal either have not submitted SIPs adequate to meet the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS, or that the SIP provisions currently in place are not adequate to meet those requirements.

As described in section IV in this preamble, EPA is proposing a state-specific methodology to identify specific reductions that states in the eastern United States must make to satisfy the CAA section 110(a)(2)(D)(i)(I) prohibition on emissions that significantly contribute to nonattainment or interfere with maintenance in a downwind state. The proposed methodology uses state-specific inputs and focuses on the emissions reductions available in each individual state to address the Court's concern that the approach used in CAIR (which identified a single level of emissions achievable by the application of highly cost effective controls in the region) was insufficiently state specific. The proposed methodology uses air quality analysis to determine whether a state's contribution to downwind air quality problems is above specific thresholds. If a state's contribution does not exceed those thresholds, its contribution is found to be insignificant and it is no longer considered in the analysis. If a state's contribution exceeds those thresholds, EPA takes a second step that uses a multi-factor analysis that takes into account both air quality and cost considerations to identify the portion of a state's contribution that is significant or that interferes with maintenance. Section 110(a)(2)(D) requires states to eliminate the emissions that constitute this "significant contribution" and "interference with maintenance."

This proposed methodology for determining upwind state emission reduction responsibility is designed to be applicable to current and potential future ozone and $PM_{2.5}$ NAAQS. It is based on cost and air quality considerations that are common to any NAAQS, but also calls for evaluation of facts specific to a particular NAAQS. As a result, application of the methodology to a revised, more stringent NAAQS might lead to a determination that greater reductions in transported pollution from upwind states are reasonable than for a current, less stringent NAAQS.

To facilitate implementation of the requirement that significant contribution and interference with maintenance be eliminated, EPA developed state emissions budgets. By tying these budgets directly to EPA's quantification of each individual state's significant contribution and interference with maintenance, EPA directly linked the budgets to the mandate in section 110(a)(2)(D)(i)(I), and thus addressed the Court's concerns about the development of budgets for the CAIR. EPA also addressed these concerns by completely eschewing any consideration or reliance on Fuel Adjustment Factors and the existing allocation of Title IV allowances.

These new emissions budgets are based on the Agency's state-by-state analysis of each upwind state's significant contribution to nonattainment and interference with maintenance downwind. A state's emissions budget is the quantity of emissions that would remain after elimination of the part of significant contribution and interference with maintenance that EPA has identified in an average year (*i.e.*, before accounting for the inherent variability in power system operations).[2] EPA proposes SO_2 and NO_X budgets for each state covered for the 24-hour and/or annual average $PM_{2.5}$ NAAQS. EPA proposes an ozone season [3] NO_X budget for each state covered for the ozone NAAQS.

EPA recognizes that baseline emissions from a state can be affected by changing weather patterns, demand growth, or disruptions in electricity supply from other units. As a result, emissions could vary from year to year in a state where covered sources have installed all controls and taken all measures necessary to eliminate the state's significant contribution and interference with maintenance. As described in detail in section IV of this preamble, EPA proposes to account for the inherent variability in power system operations through "assurance provisions" based on state variability limits which extend above the state emissions budgets. *See* section V for a detailed discussion of the assurance provisions. The small amount of variability allowed takes into account the inherent variability in baseline emissions. Section IV in this preamble describes the proposed approach to significant contribution and interference with maintenance and the state emissions budgets and variability limits in detail.

EPA is also proposing FIPs to immediately implement the emission reduction requirements identified and quantified by EPA in this action. For some covered states, these FIPs will completely satisfy the emissions reductions requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. The exception is for the 10 eastern states for which EPA has not completely quantified the total significant contribution or interference with maintenance with respect to the 1997 ozone NAAQS and the 15 states for which EPA has not completely quantified total significant contribution or interference with maintenance with respect to the 2006 $PM_{2.5}$ NAAQS in which case the FIPs would achieve measurable progress towards implementing that requirement.

The emissions reductions requirements (*i.e.*, the "remedy") that EPA is proposing to include in the FIPs responds to the Court's concerns that EPA had not shown that the CAIR reduction requirements would get all

[2] For the 10 states discussed above for which EPA has only quantified a minimum amount of emissions reductions needed to make measurable progress towards eliminating their significant contribution and interference with maintenance with respect to the 1997 8-hour ozone NAAQS, the emissions budget is the emissions that will remain after removal of those emissions.

[3] Consistent with the approach taken by the Ozone Transport Assessment Group (OTAG), the NO_X SIP call, and the CAIR, we propose to define the ozone season, for purposes of emissions reductions requirements in this rule, as May through September. We recognize that this ozone season for regulatory requirements differs from the official state-specific monitoring season.

necessary reductions "in the state" as required by section 110(a)(2)(D)(i)(I). The proposed FIPs include assurance provisions specifically designed to ensure that no state's emissions are allowed to exceed that specific state's budget plus the variability limit.

The proposed FIPs would regulate EGUs in the 32 covered states. EPA is proposing to regulate these sources through a program that uses state-specific budgets and allows intrastate and limited interstate trading. EPA is also taking comment on two alternative regulatory options. All options would achieve the emissions reductions necessary to address the emissions transport requirements in section 110(a)(2)(D)(i)(I) of the CAA.

The option EPA is proposing for the FIPs ("State Budgets/Limited Trading") would use state-specific emissions budgets and allow for intrastate and limited interstate trading. This approach would assure environmental results while providing some limited flexibility to covered sources. The approach would also facilitate the transition from CAIR to the Transport Rule for implementing agencies and covered sources.

The first alternative remedy option for which EPA requests comment would use state-specific emissions budgets and allow intrastate trading, but prohibit interstate trading. The second alternative remedy option, for which EPA also requests comment, would use state-specific budgets and emissions rate limits. See section V for further discussion of the remedy options.

The proposed remedy option and the first alternative, both of which are cap-and-trade approaches, would use new allowance allocations developed on a different basis from CAIR. Allowance allocations, like the state budgets described previously, would be developed based on the methodology used by EPA to quantify each state's significant contribution and interference with maintenance. *See* section IV for the proposed state budget approach and section V for proposed allowance allocation approaches.

In this action, EPA proposes to require reductions in SO_2 and NO_X emissions in the following 25 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the 24-hour $PM_{2.5}$ NAAQS promulgated in September 2006: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.

EPA proposes to require reductions in SO_2 and NO_X emissions in the following 24 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the annual $PM_{2.5}$ NAAQS promulgated in July 1997: Alabama, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

EPA also proposes to require reductions in ozone season NO_X emissions in the following 26 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the 1997 ozone NAAQS promulgated in July 1997: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia.

As discussed previously, EPA also is proposing FIPs to directly regulate EGU SO_2 and/or NO_X emissions in the 32 covered states. The proposed FIPs would require the 28 jurisdictions covered for purposes of the 24-hour and/or annual $PM_{2.5}$ NAAQS to reduce SO_2 and NO_X emissions by specified amounts. The proposed FIPs would require the 26 states covered for purposes of the ozone NAAQS to reduce ozone season NO_X emissions by specified amounts.

In response to the Court's opinion in *North Carolina* v. *EPA*, EPA has coordinated the compliance deadlines for upwind states to eliminate emissions that significantly contribute to or interfere with maintenance in downwind areas with the NAAQS attainment deadlines that apply to the downwind nonattainment and maintenance areas. EPA proposes to require that all significant contribution to nonattainment and interference with maintenance identified in this action with respect to the $PM_{2.5}$ NAAQS be eliminated by 2014 and proposes an initial phase of reductions starting in 2012 (covering 2012 and 2013) to ensure that the reductions are made as expeditiously as practicable and that no backsliding from current emissions levels occurs when the requirements of the CAIR are eliminated. Sources will be required to comply by January 1, 2012 and January 1, 2014 for the first and second phases, respectively. With respect to the 1997 ozone NAAQS, EPA proposes to require an initial phase of NO_X reductions starting in 2012 to ensure that reductions are made as expeditiously as practicable. Sources will be required to comply by May 1, 2012 and May 1, 2014 for the first and second phases, respectively. EPA has determined, that for many states, these reductions will be sufficient to eliminate their significant contribution with respect to the 1997 ozone NAAQS. EPA intends to issue a subsequent proposal that would require all significant contribution and interference with maintenance be eliminated by a future date for the 1997 ozone NAAQS. *See* Table III.A–1 for proposed lists of covered state.

TABLE III.A–1—LISTS OF COVERED STATES FOR $PM_{2.5}$ AND 8-HOUR OZONE NAAQS

State	Covered for 24-hour and/or annual $PM_{2.5}$	Covered for 8-hour ozone
	Required to reduce SO_2 and NO_X	Required to reduce ozone Season NO_X
Alabama	X	X
Arkansas		X
Connecticut	X	X
Delaware	X	X
District of Columbia	X	X
Florida	X	X

TABLE III.A–1—LISTS OF COVERED STATES FOR $PM_{2.5}$ AND 8-HOUR OZONE NAAQS—Continued

State	Covered for 24-hour and/or annual $PM_{2.5}$	Covered for 8-hour ozone
	Required to reduce SO_2 and NO_X	Required to reduce ozone Season NO_X
Georgia	X	X
Illinois	X	X
Indiana	X	X
Iowa	X	
Kansas	X	X
Kentucky	X	X
Louisiana	X	X
Maryland	X	X
Massachusetts	X	
Michigan	X	X
Minnesota	X	
Mississippi		X
Missouri	X	
Nebraska	X	
New Jersey	X	X
New York	X	X
North Carolina	X	X
Ohio	X	X
Oklahoma		X
Pennsylvania	X	X
South Carolina	X	X
Tennessee	X	X
Texas		X
Virginia	X	X
West Virginia	X	X
Wisconsin	X	
Totals	28	26

As discussed previously, EPA is proposing new SO_2 and/or NO_X emissions budgets for each covered state. The budgets are based on the EPA's state-by-state analysis of each upwind state's significant contribution to nonattainment and interference with maintenance downwind, before accounting for the inherent variability in power system operations.

As discussed in detail in section IV, the proposed approach to significant contribution to nonattainment and interference with maintenance would group the 28 states covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS in two tiers reflecting the stringency of SO_2 reductions required to eliminate that state's significant contribution to nonattainment and interference with maintenance. There would be a stringent SO_2 tier comprising 15 states ("group 1") and a moderate SO_2 tier comprising 13 states ("group 2"), with uniform stringency within each tier.[4] For these same 28 states, there would be one annual NO_X tier with uniform stringency of NO_X reductions across all 28 states. Similarly, for the 26 states covered for the ozone NAAQS there would be one ozone season NO_X tier with uniform stringency across all 26 states.

The proposed stringent SO_2 tier ("group 1") would include Georgia, Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. The proposed moderate SO_2 tier ("group 2") would include Alabama, Connecticut, Delaware, District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey, and South Carolina.

As discussed previously, EPA proposes to require an initial phase of reductions starting in 2012 (covering 2012 and 2013) requiring SO_2 and NO_X reductions in the 28 states covered for 24-hour and/or annual $PM_{2.5}$ NAAQS. A second phase of reductions would be due in 2014, covering 2014 and thereafter. As described later, for certain states the 2014 reduction requirements would be more stringent, and for certain states would remain at the same level as the 2012 requirements.

For the 15 states in the stringent SO_2 tier ("group 1"), the 2014 phase would substantially increase the SO_2 reduction requirements (*i.e.*, these states would have smaller SO_2 emissions budgets starting in 2014), reflecting the greater reductions needed to eliminate the portion of significant contribution and interference with maintenance that EPA has identified in this proposal from these states with respect to the 24-hour $PM_{2.5}$ NAAQS. For the 13 states in the moderate SO_2 tier ("group 2"), the 2014 SO_2 emissions budgets would remain the same as the 2012 SO_2 budgets for these states.

The 2014 annual NO_X emissions budgets for all 28 states covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS would remain the same as the 2012 annual NO_X budgets.

With respect to the ozone NAAQS, EPA is proposing a single phase of reductions which begins in 2012. Thus, the rule does not call for any adjustment to be made to the 2012 ozone season NO_X budgets for the 26 states covered for the ozone NAAQS. EPA intends to issue a subsequent proposal that would, among other things, address whether an additional phase of NO_X reductions is necessary to address all significant

[4] With regard to interstate trading, the two SO_2 stringency tiers would lead to two exclusive SO_2 trading groups. That is, states in SO_2 group 1 could not trade with states in SO_2 group 2.

contribution and interference with maintenance with respect to the 1997 ozone NAAQS. While this proposal assures downwind states that they will receive relief from upwind reductions that will help them achieve the NAAQS, EPA is committed to fulfilling its obligation to assure the downwind states that they receive the full relief they are entitled to under section 110(a)(2)(D). The Agency intends to quickly address any remaining significant contribution to nonattainment and interference with maintenance in a subsequent action that will also address a new more stringent ozone standard that is expected to be established by EPA later in 2010.

Tables III.A–2 and III.A–3 show projected Transport Rule emissions reductions for EGUs in all states that EPA proposes to cover.

TABLE III.A–2—PROJECTED SO_2 AND NO_X EGU EMISSIONS IN COVERED STATES WITH THE TRANSPORT RULE [5] COMPARED TO BASE CASE [6] WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 Base case emissions	2012 Transport rule emissions	2012 Emissions reductions	2014 Base case emissions	2014 Transport rule emissions	2014 Emissions reductions
SO_2	8.4	3.4	5.0	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.3	0.7
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

TABLE III.A–3—PROJECTED SO_2 AND NO_X EGU EMISSIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS

[Million tons]

	2005 Actual emissions	2012 Transport rule emissions	2012 Emissions reductions from 2005	2014 Transport rule emissions	2014 Emissions reductions from 2005
SO_2	8.9	3.4	5.5	2.6	6.3
Annual NO_X	2.7	1.3	1.4	1.3	1.4
Ozone Season NO_X	0.9	0.6	0.3	0.6	0.3

In addition to the emissions reductions shown previously, EPA projects other substantial benefits, as described in section IX in this preamble. Air quality modeling was used to quantify the improvements in $PM_{2.5}$ and ozone concentrations that are expected to result from the emissions reductions in 2014. The results of this modeling were used to calculate the average reduction in annual average $PM_{2.5}$, 24-hour average $PM_{2.5}$, and 8-hour ozone concentrations for monitoring sites in the eastern U.S. that are projected to be nonattainment in the 2014 base case. For annual $PM_{2.5}$ and 24-hour $PM_{2.5}$, the average reductions are 2.4 micrograms per cubic meter ($\mu g/m^3$) and 4.3 $\mu g/m^3$, respectively. The average reduction in 8-hour ozone at monitoring sites projected to be nonattainment in the 2014 base case is 0.3 parts per billion (ppb). The reductions in annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and ozone concentrations for individual nonattainment and/or maintenance sites are provided in section IX.

Table III.A–4 compares projected EGU emissions with the Transport Rule to projected EGU emissions with CAIR.

TABLE III.A–4—SIMPLE COMPARISON OF SO_2 AND NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN STATES IN THE CAIR OR TRANSPORT RULE REGIONS * FOR EACH RULE

		2005	2012		2014	
		Actual	Transport rule	CAIR **	Transport rule	CAIR **
SO_2 (Million Tons)		9.5	4.1	5.1	3.3	4.6
NO_X (Million Tons)	Annual	2.9	1.6	1.7	1.6	1.7
	Ozone Season	1.0	0.7	0.8	0.7	0.8

* Emissions totals include states covered by either the Transport Rule or CAIR. For $PM_{2.5}$ (SO_2 and annual NO_X), the following 30 states are included: AL, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MS, MO, NE, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI. For ozone (ozone-season NO_X), the following 30 states are included: AL, AR, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MS, MO, NJ, NY, NC, OH, OK, PA, SC, TN, TX, VA, WV, WI.

** CAIR SO_2 totals are interpolations from emissions analysis originally done for 2010 and 2015. CAIR NO_X totals are as originally projected for 2010. This CAIR modeling represents a scenario that differed somewhat from the final CAIR (the modeling did not include a regionwide ozone season NO_X cap and included $PM_{2.5}$ requirements for the state of Arkansas).

[5] Projected Transport Rule emissions result from individual stae budgets in the proposed approach and include some banking of allowances in 2012 adn use of that bank in 2014.

[6] EPA's base case EGU emissions modeling does not assume enforceable SO_2 or NO_X reductions attributed to the Transport Rule or CAIR. In this base case, a unit with existing SO_2 or NO_X control equipment, but without an enforceable federal or state control requirement, is allowed to choose its most economic approach to operation within existing Acid Rain Program requirements and may opt not to operate a control. *See* section IV.C.1 and the IPM Documentation for further information on the base case modeling.

In addition to discussion of EPA's proposed regulatory approach (discussed in sections IV and V), this preamble also covers the stakeholder outreach EPA conducted (section VI), SIP submissions (section VII), permitting (section VIII), projected benefits of the proposed rule (section IX), economic impacts (section X), end-use energy efficiency (section XI), and statutory and executive order reviews (section XII).

Table III.A–5 shows the results of the cost and benefits analysis for the proposed and alternate remedies. Further discussion of these results is contained in preamble section XII-A and in the Regulatory Impacts Analysis. A listing of health and welfare effects is provided in RIA Table 1–6. Estimates here are subject to uncertainties discussed further in the body of the document. The social costs are the loss of household utility as measured in Hicksian equivalent variation. The capital costs spent for pollution controls installed for CAIR were not included in the annual social costs since the Transport Rule did not lead to their installation. Those CAIR-related capital investments are roughly estimated to have an annual social cost less than $1.15 to $ 1.29 billion (under the two discount rates.)

Most of the estimated PM-related benefits in this rule accrue to populations exposed to higher levels of $PM_{2.5}$. Of these estimated PM-related mortalities avoided, about 80 percent occur among populations initially exposed to annual mean $PM_{2.5}$ level of 10 $\mu g/m^3$ and about 97 percent occur among those initially exposed to annual mean $PM_{2.5}$ level of 7.5 $\mu g/m^3$. These are the lowest air quality levels considered in the Laden *et al.* (2006) and Pope *et al.* (2002) studies, respectively. This fact is important, because as we estimate PM-related mortality among populations exposed to levels of $PM_{2.5}$ that are successively lower, our confidence in the results diminishes. However, our analysis shows that the great majority of the impacts occur at higher exposures.

TABLE III.A–5—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF VERSIONS OF THE PROPOSED REMEDY OPTION IN 2014 [a]

[Billions of 2006$]

Description	Preferred remedy—State budgets/ limited trading	Direct control	Intrastate trading
Social costs:			
3% discount rate	$2.03	$2.68	$2.49.
7% discount rate	$2.23	$2.91	$2.70.
Health-related benefits: [b, c]			
3% discount rate	$118 to $288 + B	$117 to $286 + B	$113 to $276 + B.
7% discount rate	$108 to $260 + B	$108 to $262 + B	$104 to $252 + B.
Net benefits (benefits-costs):			
3% discount rate	$116 to $286	$115 to $283	$110 to $273.
7% discount rate	$105 to $258	$105 to $259	$101 to $249.

Notes: (a) All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for the year 2014. For notational purposes, unquantified benefits are indicated with a "B" to represent the sum of additional monetary benefits and disbenefits. Data limitations prevented us from quantifying these endpoints, and as such, these benefits are inherently more uncertain than those benefits that we were able to quantify. (b) The reduction in premature mortalities account for over 90 percent of total monetized benefits. Benefit estimates are national. Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 5. Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000; OMB, 2003). The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in Chapter 5. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). Monetized benefits do not include unquantified benefits, such as other health effects, reduced sulfur deposition or visibility. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. (c) Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in RIA Table 1–4.

B. Background

1. What is the source of EPA's authority for this action?

The statutory authority for this action is provided by the CAA, as amended (42 U.S.C. 7401 *et seq.*). Relevant portions of the CAA include, but are not necessarily limited to, sections 110(a)(2)(D), 110(c)(1), and 301(a)(1).

Section 110(a)(2)(D) of the CAA, often referred to as the "good neighbor" provision of the Act, requires states to prohibit certain emissions because of their impact on air quality in downwind states. Specifically, it requires all states, within 3 years of promulgation of a new or revised NAAQS, to submit SIPs that:

(D) Contain adequate provisions—

(i) Prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—

(I) Contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, or

(II) Interfere with measures required to be included in the applicable implementation plan for any other State under part C of this subchapter to prevent significant deterioration of air quality or to protect visibility.

(ii) Insuring compliance with the applicable requirements of sections 7426 and 7415 of this title (relating to interstate and international pollution abatement). 42 U.S.C. 7410(a)(2)(D).

This proposal addresses the requirement in section 110(a)(2)(D)(i)(I) regarding the prohibition of emissions within a state that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state. As discussed in greater detail later, EPA has previously issued two rules interpreting and clarifying the requirements of section 110(a)(2)(D)(i)(I). The NO_X SIP Call, promulgated in 1998, was largely upheld by the U.S. Court of Appeals for the DC Circuit in *Michigan* v. *EPA*, 213 F.3d 663 (DC Cir. 2000). The CAIR, promulgated in 2005, was remanded by the DC Circuit in *North Carolina* v. *EPA*, 531 F.3d 896 (DC Cir. 2008), *modified on reh'g*, 550 F.3d. 1176 (DC Cir. 2008). These decisions provide additional guidance regarding the requirements of section 110(a)(2)(D)(i)(I) and are discussed later in this section.

Section 301(a)(1) of the CAA gives the Administrator of EPA general authority to "prescribe such regulations as are necessary to carry out [her] functions under this chapter." 42 U.S.C. 7601(a)(1). Pursuant to this section, EPA has authority to clarify the applicability of CAA requirements. In this action,

EPA is clarifying the applicability of section 110(a)(2)(D)(i)(I) by proposing to identify SO_2 and NO_X emissions that each affected state must prohibit pursuant to that section with respect to the $PM_{2.5}$ NAAQS promulgated in 1997 and 2006 and the 8-hour ozone NAAQS promulgated in 1997. The improvements in air quality that would result from the reductions in upwind state emissions that EPA is proposing to require would assist downwind states affected by transported pollution in developing, pursuant to section 110 of the CAA, their SIPs to provide for expeditious attainment and maintenance of the NAAQS.

Section 110(a) of the CAA assigns to each state both the primary responsibility for attaining and maintaining the NAAQS within such state, 42 U.S.C. 7410(a)(1), and the primary responsibility for prohibiting emissions activity within the state which will significantly contribute to nonattainment or interfere with maintenance in a downwind area. 42 U.S.C. 7410(a)(2)(D)(i)(I). States fulfill these CAA obligations through the SIP process described in section 110(a) of the Act.

Section 110(c)(1) of the Act, however, requires EPA to act when a state has not been able to or has not fulfilled its obligation to submit a SIP that meets the requirements of the Act. Specifically, section 110(c)(1) provides that: The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) Finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A) of this section, or

(B) Disapproves a State implementation plan submission in whole or part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.

42 U.S.C. 7410(c)(1). Section 110(k)(1)(A), in turn, calls for the Administrator to establish criteria for determining whether SIP submissions are complete. 42 U.S.C. 7410(k)(1)(A).

As discussed in greater detail in section VII, for all states covered by the FIPs proposed in this action, EPA either has taken, has proposed to take, or believes it may need to take one of the following actions with respect to the 1997 ozone NAAQS, the 1997 $PM_{2.5}$ NAAQS and/or the 2006 $PM_{2.5}$ NAAQS: (1) Find that the state has failed to make a SIP submission required by section 110(a)(2)(D)(i)(I) or section 110(k)(5) of the Act; (2) find that such a SIP submission is incomplete; or (3) disapprove such a SIP submission. Once EPA has taken one of the these actions, pursuant to section 110(c)(1), it has authority to promulgate a FIP directly implementing the requirements of section 110(a)(2)(D)(i)(I), provided the state has not submitted and EPA has not approved a SIP submission that corrects the SIP deficiency prior to promulgation of the FIP.

2. What air quality problems does this proposal address?

a. Fine Particles

Fine particles are associated with a number of serious health effects including premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, health-related absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems. *See* EPA, Air Quality Criteria for Particulate Matter (EPA/600/P–99/002bF, October 2004) at 9.2.2.3. *See* also integrated science assessment for the PM NAAQS review, December 2009, *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*. Individuals particularly sensitive to fine particle exposure include older adults, people with heart and lung disease, and children. This rule, and the NAAQS to which it is related, consider the effects of fine particles on vulnerable populations (*see* further discussion in section XII.G and section XII.J of this notice). More detailed information on health effects of fine particles can be found on EPA's Web site at: *http://epa.gov/pm/standards.html*.

In addition to effects on public health, fine particles are linked to a number of public welfare effects. First, $PM_{2.5}$ are the major cause of reduced visibility (haze) in parts of the United States, including many of our national parks and wilderness areas. For more information about visibility, visit EPA's Web site at *http://www.epagov/visibility*. Second, particles can be carried over long distances by wind and then settle on ground or water. The effects of this settling include: Making lakes and streams acidic; changing the nutrient balance in coastal waters and large river basins; depleting the nutrients in soil; damaging sensitive forests and farm crops; and affecting the diversity of ecosystems. More information about these effects is available at EPA's Web site at *http://www.epa.gov/acidrain/effects/index.html*. Finally, particle pollution can stain and damage stone and other materials, including culturally important objects such as statues and monuments.

In 1997, EPA revised the NAAQS for PM to add new annual average and 24-hour standards for fine particles, using $PM_{2.5}$ as the indicator (62 FR 38652). These revisions established an annual standard of 15 $\mu g/m^3$ and a 24-hour standard of 65 $\mu g/m^3$. During 2006, EPA revised the air quality standards for $PM_{2.5}$. The 2006 standards decreased the level of the 24-hour fine particle standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$, and retained the annual fine particle standard at 15 $\mu g/m^3$.

In the preamble to the final rule for CAIR in May 2005, EPA discussed ambient monitoring for 2001–2003, the most recent 3-year period available at the time. These results showed widespread exceedances of the 15 $\mu g/m^3$ annual $PM_{2.5}$ standard in the eastern United States, with additional exceedances in parts of California and one county in Montana. At that time, 82 counties in the U.S. had at least one monitor that violated the 1997 annual $PM_{2.5}$ standard.

The $PM_{2.5}$ ambient air quality monitoring for the 2006–2008 period (most recent available) shows significant improvements. Nonetheless, areas which continue to violate the 15 $\mu g/m^3$ annual $PM_{2.5}$ standard are located across a significant portion of the eastern half of the United States, in parts of California and one county in Arizona. Based on these nationwide data, 23 counties have at least one monitor that violates the annual $PM_{2.5}$ standard.

The $PM_{2.5}$ ambient air quality monitoring for this same 2006–2008 time period shows that areas violating the 2006 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$ (*i.e.*, the revised 2006 standard for 24-hour $PM_{2.5}$) are located across much of the eastern half of the United States, in parts of California, and in some counties in several other western states—Alaska, Washington, Oregon, Utah, and Arizona. Based on these nationwide data, 52 counties have at least one monitor that violates the 24-hour $PM_{2.5}$ standard.

EPA believes that a great deal of the improvement in $PM_{2.5}$ annual and 24-hour concentrations in the eastern U.S. can be attributed to EGU SO_2 reductions achieved due to the CAIR. While the CAIR requirements related to SO_2 did not begin until 2010, many actions were taken by EGU owners and operators in anticipation of those requirements. Emissions of SO_2 from EGUs covered by the CAIR that were also in the acid rain

program (under CAA Title IV) tracking system decreased from 10.2 million tons in 2005 to 7.6 million tons in 2008. Almost all of these emissions reductions were achieved in the areas of the eastern United States covered by the CAIR. See *http://www.epa.gov/airmarkt/progress/ARP_4.html*. EPA believes that there would be substantially more nonattainment counties for both the annual and 24-hour standards if the CAIR were not in effect.

As required by the CAA, and in response to litigation over the 2006 standards, EPA is currently conducting a review of the 2006 $PM_{2.5}$ standards. Information and documents related to this review are available at: *http://epa.gov/ttn/naaqs/standards/pm/s_pm_index.html*. EPA expects to complete this review and to publish any revised standards that may result from the review by October 2011. EPA is planning to propose the revised standards by February 2011.

b. Ozone

Short-term (1- to 3-hour) and prolonged (6- to 8-hour) exposures to ambient ozone have been linked to a number of adverse health effects. At sufficient concentrations, short-term exposure to ozone can irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone can reduce lung function and make it more difficult to breathe deeply. Breathing may become more rapid and shallow than normal, thereby limiting a person's normal activity. Ozone also can aggravate asthma, leading to more asthma attacks that may require a doctor's attention and the use of additional medication. Increased hospital admissions and emergency room visits for respiratory problems have been associated with ambient ozone exposures. Longer-term ozone exposure can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. A lower quality of life may result if the inflammation occurs repeatedly over a long time period (such as months, years, or a lifetime). There is also recent epidemiological evidence indicating that there is a correlation between short-term ozone exposure and premature mortality.

People who are particularly susceptible to the effects of ozone include people with respiratory diseases, such as asthma. Those who are exposed to higher levels of ozone include adults and children who are active outdoors. This rule, and the NAAQS which it is related to, consider the effects of ozone on vulnerable populations (*see* further discussion in section XII.G and section XII.J of this notice).

In addition to causing adverse health effects, ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests, and other environmental stresses (*e.g.*, harsh weather). In long-lived species, these effects may become evident only after several years or even decades and have the potential for long-term adverse impacts on forest ecosystems. Ozone damage to the foliage of trees and other plants can also decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of our national parks and recreation areas. More detailed information on effects of ozone can be found at the following EPA Web site: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html*.

In 1997, at the same time we revised the $PM_{2.5}$ standards, EPA issued its final action to revise the NAAQS for ozone (62 FR 38856) to establish new 8-hour standards. In this action published on July 18, 1997, we promulgated identical revised primary and secondary ozone standards that specified an 8-hour ozone standard of 0.08 parts per million (ppm). Specifically, the standards require that the 3-year average of the fourth highest 24-hour maximum 8-hour average ozone concentration may not exceed 0.08 ppm. In general, the 8-hour standards are more protective of public health and the environment and more stringent than the pre-existing 1-hour ozone standards.

At the time EPA published the CAIR and the CAIR FIP rulemakings, wide geographic areas, including most of the nation's major population centers, experienced ozone levels that violated the 1997 NAAQS of 8-hour ozone 0.08 ppm (effectively 0.084 ppm as a result of rounding). These areas included much of the eastern part of the United States and large areas of California. The EPA published the 8-hour ozone attainment and nonattainment designations in the **Federal Register** on April 30, 2004 (69 FR 23858). These designations, based on ozone season monitoring data for the 2001–2003 time period, resulted in 112 areas designated as nonattainment. As of December 2009, significant emissions reductions have allowed 58 of the original 112 nonattainment areas to be re-designated to attainment. In addition, a number of areas still designated as nonattainment ozone monitoring data for 2006–2008 (most recent data available) show levels below the standard. EPA believes a number of factors contributed to NO_X emissions reductions subsequent to the 2001–2003 time period. First, EGU emissions were substantially reduced as EGUs in the eastern U.S. came into compliance with the NO_X SIP Call. A series of progress reports discussing the effect of the NO_X SIP Call reductions can be found on EPA's Web site at: *http://www.epa.gov/airmarkets/progress/progress-reports.html*. Additional information on emissions and air quality trends are available in EPA's 2007 and 2008 air quality trends reports, which are available at: *http://www.epa.gov/airtrends/*.

Second, mobile source emissions standards for onroad gasoline and vehicle emissions standards began to reduce mobile source emissions as the fleet began turning over vehicles to meet tightened NO_X emissions standards. Continued improvement in ozone is expected with continued reductions in mobile source emissions.

On March 12, 2008, EPA published a revision to the 8-hour ozone standard, lowering the level from 0.08 ppm to 0.075 ppm. On September 16, 2009, EPA announced it would reconsider these 2008 ozone standards. The purpose of the reconsideration is to ensure that the ozone standards are clearly grounded in science, protect public health with an adequate margin of safety, and are sufficient to protect the environment. EPA proposed revisions to the standards on January 19, 2010 (75 FR 2938) and will issue final standards soon. Information on the 2008 revisions to the ozone standard, and on all subsequent activity based on the reconsideration, is available at: *http://www.epa.gov/air/ozonepollution/actions.html#sep09s*.

3. Which NAAQS does this proposal address?

This proposed action addresses the requirements of CAA section 110(a)(2)(D)(i)(I) as they relate to:

(1) The 1997 annual $PM_{2.5}$ standards,

(2) The 2006 daily $PM_{2.5}$ standards, and

(3) The 1997 ozone standards

The original CAIR and CAIR FIP rules, which pre-dated the 2006 standards, addressed the 1997 ozone and $PM_{2.5}$ standards only. The 1997 8-hour ozone standard is 0.08 ppm. The 1997 $PM_{2.5}$ standards promulgated in 1997 established a 15 $\mu g/^3$ standard for 24-hour $PM_{2.5}$ and a 65 $\mu g/m^3$ standard for annual $PM_{2.5}$. In 2006, the 24-hour $PM_{2.5}$ standard was lowered to 35 $\mu g/m^3$ and the 15 $\mu g/m^3$ annual $PM_{2.5}$ standard was left unchanged.

For this proposal, EPA fully addresses the requirements of CAA section 110(a)(2)(D)(i)(I) for the annual $PM_{2.5}$ standard of 15 μg/m³. For the 24-hour standard of 35 μg/m³ and for the 1997 8-hour ozone standard of 0.08 ppm, EPA fully addresses the CAA section 110(a)(2)(D)(i)(I) requirements for some states, but for the remaining states EPA will address whether further requirements are needed.

This action does not address the CAA section 110(a)(2)(D)(i)(I) requirements for the revised ozone standards promulgated in 2008. These standards are currently under reconsideration. We are, however, actively conducting the technical analyses and other work needed to address interstate transport for the reconsidered ozone standard as soon as possible. We intend to issue as soon as possible a proposal to address the transport requirements with respect to the reconsidered standard.

4. EPA Transport Rulemaking History

a. CAA Provisions

For almost 40 years, Congress has focused major efforts on curbing ground-level ozone. In 1970, Congress amended the CAA to require, in Title I, that EPA issue and periodically review and, if necessary, revise NAAQS for ubiquitous air pollutants (sections 108 and 109). Congress required the states to submit SIPs to attain and maintain those NAAQS, and Congress included, in section 110, a list of minimum requirements that SIPs must meet. Congress anticipated that areas would attain the NAAQS by 1975.

In 1977, Congress amended the CAA by providing, among other things, additional time for areas that were not attaining the ozone NAAQS to do so, as well as by imposing specific SIP requirements for those nonattainment areas. These provisions first required the designation of areas as attainment, nonattainment, or unclassifiable, under section 107; and then required that SIPs for ozone nonattainment areas include the additional provisions set out in part D of Title I, as well as demonstrations of attainment of the ozone NAAQS by either 1982 or 1987 (section 172).

In addition, the 1977 Amendments included two provisions focused on interstate transport of air pollutants: the predecessor to current section 110(a)(2)(D), which requires SIPs for all areas to constrain emissions with certain adverse downwind effects; and section 126, which, in general, authorizes a downwind state to petition EPA to impose limits directly on upwind sources found to adversely affect that state. Section 110(a)(2)(D)(i)(I), which is key to the present action, is described in more detail later.

In 1990, Congress amended the CAA to better address, among other things, continued nonattainment of the 1-hour ozone NAAQS, the requirements that would apply if EPA revised the 1-hour standard, and transport of air pollutants across state boundaries (Pub. L. 101–549, Nov. 15, 1990, 104 Stat. 2399, 42 U.S.C. 7401–7671q).

As amended in 1990, the CAA further requires EPA to designate areas as attainment, nonattainment, and unclassifiable under a revised NAAQS (section 107(d)(1); section 6103, Pub. L. 105–178). The CAA authorizes EPA to classify areas that are designated nonattainment under the new NAAQS and to establish for those areas attainment dates that are as expeditious as practicable, but not to exceed 10 years from the date of designation (section 172(a)).

All areas are required to submit SIPs within certain timeframes (section 110(a)(1)), and those SIPs must include specified provisions, under section 110(a)(2). In addition, SIPs for nonattainment areas are generally required to include additional specified control requirements, as well as controls providing for attainment of any revised NAAQS and periodic reductions providing "reasonable further progress" in the interim (section 172(c)). If states do not submit SIPs in a timely or approvable manner, EPA has the authority to make findings of failure to submit or impose FIPs on specific sources in the state that contribute to downwind nonattainment and interference with maintenance. Significant contribution and interference with maintenance are discussed in detail in section IV later.

The 1990 Amendments reflect general awareness by Congress that ozone is a regional, and not merely a local, problem. Ozone and its precursors may be transported long distances across state lines, thereby exacerbating ozone problems downwind. Ozone transport is recognized as a major reason for the persistence of the ozone problem, notwithstanding the imposition of numerous controls, both Federal and State, across the country.

The CAA further addresses interstate transport of pollution in section 126, which Congress revised slightly in 1990. Subsection (b) of that provision authorizes each state (or political subdivision) to petition EPA for a finding designed to protect that entity from upwind sources of air pollutants.[7]

In addition, the 1990 Amendments added section 184, which delineates a multi-state ozone transport region (OTR) in the Northeast, requires specific additional controls for all areas (not only nonattainment areas) in that region, and establishes the Ozone Transport Commission (OTC) for the purpose of recommending to EPA regionwide controls affecting all areas in that region. At the same time, Congress added section 176A, which authorized the formation of transport regions for other pollutants and in other parts of the country.

In September 1994, the Northeast OTC states signed a Memorandum of Understanding (MOU) committing to reduce NO_X emissions throughout the region. In 1999 through 2002, most of the OTC states achieved substantial NO_X reductions through an ozone season cap and trade program for NO_X called the OTC NO_X Budget Program, which EPA administered, and through NO_X emissions rate limits from certain coal plants under Title IV.

Separate from activity in the OTC, EPA and the Environmental Council of the States (ECOS) formed the OTAG in 1995. This workgroup brought together interested states and other stakeholders, including industry and environmental groups. Its primary objective was to assess the ozone transport problem and develop a strategy for reducing ozone pollution throughout the eastern half of the United States.

Notwithstanding significant efforts, the states generally were not able to meet the November 15, 1994 statutory deadline for the attainment demonstration and rate of progress (ROP) SIP submissions required under section 182(c). The major reason for this failure was that at that time, states with downwind nonattainment areas were not able to address transport from upwind areas. As a result, EPA recognized that development of the necessary technical information, as well as the control measures necessary to achieve the large level of reductions likely to be required, had been particularly difficult for the states affected by ozone transport.

Accordingly, as an administrative remedial matter, EPA established new timeframes for the required SIP submittals. To allow time for states to incorporate the results of the OTAG

[7] In addition, section 115 authorizes EPA to require a SIP revision in certain circumstances when one or more sources within a state "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare in a foreign country."

modeling into their local plans, EPA extended the submittal date to April 1998.[8] The OTAG's air quality modeling and recommendations formed the basis for what became the NO_X SIP Call rulemaking and included the most comprehensive analyses of ozone transport ever conducted. The EPA participated extensively in the OTAG process that generated much useful technical and modeling information on regional ozone transport.

OTAG was established to address transport issues associated with meeting the 1-hour standard. The EPA did not promulgate the 8-hour standard until shortly after OTAG concluded; thus, OTAG did not recommend strategies to address the 8-hour NAAQS. However, because EPA had proposed an 8-hour standard, OTAG did examine the impacts of different strategies on 8-hour average ozone predictions. They found that ozone transport caused problems for downwind areas under either the 1-hour or 8-hour standard.

EPA's Transport SIP Call Regulatory Efforts. Shortly after OTAG began its work, EPA indicated that it intended to issue a SIP call to require states to implement the reductions necessary to address the ozone transport problem. On January 10, 1997 (62 FR 1420), EPA published a notice of intent and indicated that before taking final action, EPA would carefully consider the technical work and any recommendations of OTAG. The EPA published the NPR for the NO_X SIP Call by notice dated November 7, 1997 (62 FR 60319). The NPR proposed to make a finding of significant contribution due to transported NO_X emissions to nonattainment or maintenance problems downwind and to assign NO_X emissions budgets for 23 jurisdictions. In light of OTAG's work and additional information, EPA was able to assess ozone transport as it relates to the 8-hour NAAQS and to set forth requirements as necessary to address the 8-hour standard in the rulemaking. The regional reductions of NO_X that would have been achieved through this SIP call for the 1-hour NAAQS were key components for meeting the new 8-hour ozone standard in a cost-effective manner. Therefore, EPA believed that the OTAG recommendations for how to address ozone transport were valid for both NAAQS.

The EPA published a supplemental notice of proposed rulemaking (SNPR) dated May 11, 1998 (63 FR 25902), which proposed a model NO_X budget trading program and state reporting requirements and provided the air quality analyses of the proposed statewide NO_X emissions budgets.

Revision of the Ozone NAAQS. On July 18, 1997 (62 FR 38856), EPA issued its final action to revise the NAAQS for ozone. The EPA's decision to revise the standard was based on the Agency's review of the available scientific evidence linking exposures to ambient ozone to adverse health and welfare effects at levels allowed by the pre-existing 1-hour ozone standards. The 1-hour primary standard was replaced by an 8-hour standard at a level of 0.08 ppm, with a form based on the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration measured at each monitor within an area. The new primary standard provided increased protection to the public, especially children and other at-risk populations, against a wide range of ozone-induced health effects.

The pre-existing 1-hour secondary ozone standard was replaced by an 8-hour standard identical to the new primary standard. The new secondary standard provided increased protection to the public welfare against ozone-induced effects on vegetation.

Section 126 Petitions. In a separate rulemaking, EPA proposed action on petitions submitted by 8 northeastern states[9] under section 126 of the CAA. Each petition specifically requested that EPA make a finding that NO_X emissions from certain major stationary sources significantly contributed to ozone nonattainment problems in the petitioning state. Both the NO_X SIP Call and the section 126 petitions were designed to address ozone transport through reductions in upwind NO_X emissions. However, the EPA's response to the section 126 petitions differed from EPA's action in the NO_X SIP Call rulemaking in several ways. In the NO_X SIP Call, EPA was determining that certain states were or would be significantly contributing to nonattainment or maintenance problems in downwind states. The EPA required the upwind states to submit SIP provisions to reduce the amounts of each state's NO_X emissions that significantly contributed to downwind air quality problems. The states had the discretion to select the mix of control measures to achieve the necessary reductions. By contrast, under section 126, if findings of significant contribution were made for any sources identified in the petitions, EPA would have determined the necessary emissions limits to address the amount of significant contribution and would have directly regulated the sources. A section 126 remedy would have applied only to sources in states named in the petitions.

b. NO_X SIP Call

Based on the findings of OTAG, EPA proposed a rulemaking known as the NO_X SIP Call in 1997 and finalized it in 1998. (*See* "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," (63 FR 57356).) This rule concluded that NO_X emissions in 22 states and the District of Columbia contribute to ozone nonattainment in other states, and the rule required affected states to amend their SIPs and limit NO_X emissions. EPA set an ozone season NO_X budget for each affected state, essentially a cap on ozone season (summertime) NO_X emissions in the state. Sources in the affected states were given the option to participate in a regional cap and trade program. The first control period was scheduled for the 2003 ozone season.

In response to litigation over EPA's final NO_X SIP Call rule, the Court issued two decisions concerning the NO_X SIP Call and its technical amendments.[10] The Court decisions, discussed later, generally upheld the NO_X SIP Call and technical amendments, including EPA's interpretation of the definition of "contribute significantly" under CAA section 110(a)(2)(D). The litigation over the NO_X SIP Call coincided with the litigation over the 8-hour NAAQS. Because of the uncertainty caused by the litigation on the 8-hour NAAQS, EPA stayed the portion of the NO_X SIP Call based on the 8-hour NAAQS (65 FR 56245, September 18, 2000). Therefore, for the most part, the Court did not address NO_X SIP Call requirements under the 8-hour ozone NAAQS.

(1) What was the NO_X SIP Call?

The NO_X SIP Call was EPA's principal effort to reduce interstate transport of precursors for both the 1-hour ozone NAAQS and the 8-hour ozone NAAQS. The EPA's rulemaking was based on its consideration of OTAG's recommendations, as well as information resulting from EPA's additional work, and extensive public input generated through notice-and-comment rulemaking. The EPA believed

[8] Guidance for Implementing the 1-hour Ozone and Pre-Existing PM10 NAAQS, Memorandum from Richard D. Wilson, dated December 29, 1997.

[9] The 8 states were Connecticut, Massachusetts, Maine, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont.

[10] *See Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), cert. denied, 532 U.S. 904 (2001) (NO_X SIP call) and *Appalachian Power* v. *EPA,* 251 F.3d 1026 (DC Cir. 2001) (technical amendments).

that requiring NO_X emissions reductions across the region in amounts achievable by uniform controls was a reasonable, cost-effective step to take to mitigate ozone nonattainment in downwind states for both the 1-hour and 8-hour standards.

It was also EPA's goal to ensure that sufficient regional reductions were achieved to mitigate ozone transport in the eastern half of the United States and thus, in conjunction with local controls, enable nonattainment areas to attain and maintain the ozone NAAQS.

This NO_X SIP Call required those jurisdictions that EPA determined significantly contribute to 1-hour and 8-hour ozone nonattainment problems in downwind states to revise their SIPs to include NO_X control measures to mitigate the significant ozone transport during summer months known as the "ozone season" (May–September). The EPA determined emissions reductions requirements for the covered states and source categories (*see* section IV.A for a description of the approach EPA used to determine emissions reductions requirements). The affected states were required to submit SIPs providing the specified amounts of emissions reductions. By eliminating these amounts of NO_X emissions, the control measures would assure that the remaining NO_X emissions would meet the level identified in the rule as the state's NO_X emissions budget and would not "significantly contribute to nonattainment, or interfere with maintenance by," a downwind state, under section 110(a)(2)(D)(i)(I).

The SIP requirements permitted each state to determine what measures to adopt to prohibit the significant amounts and hence meet the necessary emissions budget. Consistent with OTAG's recommendations to achieve decreased NO_X emissions primarily from large stationary sources in a trading program, EPA encouraged states to consider electric utility and large boiler controls under a cap and trade program as a cost-effective strategy. The EPA also recognized that promotion of energy efficiency could contribute to a cost-effective strategy. *See* section V.D.1 for a discussion on the approach taken to implement the emissions reductions requirements in the NO_X SIP Call.

(2) Legal Challenges to the NO_X SIP Call

Several petitioners challenged the NO_X SIP Call in the United States Court of Appeals for the District of Columbia Circuit (DC Circuit). In *Michigan* v. *EPA*, 213 F.3d 663 (DC Cir., 2000), *cert. denied*, 532 U.S. 904 (2001), the Court upheld the rule in most respects. Of greatest relevance here, the Court upheld the essential features of EPA's approach to identifying and eliminating states" NO_X emissions that significantly contribute to downwind nonattainment. It upheld key aspects of EPA's air quality modeling and its use of cost-effectiveness criteria in defining states" "significant contribution." *See id.* at 673–79. In addition, it accepted EPA's use of a uniform control requirement (*i.e.*, requiring all covered jurisdictions, regardless of amount of contribution, to reduce NO_X emissions by an amount achievable with highly cost effective controls). *See id.* at 679–80. The Court, however, agreed with petitioners that certain specific applications of EPA's approach were flawed. It thus vacated the rule with respect to Wisconsin, Missouri, and Georgia, and held that EPA had failed to provide adequate notice on two specific issues (a change in the definition of EGU and a change in control level assumed for specific sources). *See id.* at 681–85, 692–94. The Court also subsequently delayed the implementation date to May 31, 2004. *Michigan* v. *EPA, 2000 WL 1341477 (DC Cir. 2000).*

The decision resolved only issues involving the 1-hour ozone NAAQS and did not resolve any issues involving the 8-hour NAAQS, which provided another basis for the rule. *See id.* at 670–71. EPA ultimately stayed the 8-hour basis of the NO_X SIP Call. *See* 65 FR 56245. In addition, in a subsequent case that reviewed separate EPA rulemakings making technical corrections to the NO_X SIP Call, the DC Circuit remanded the case for a better explanation of EPA's methodology for computing the growth component in the EGU heat input calculation. *See Appalachian Power Co.* v. *EPA*, 251 F.3d 1026 (DC Cir. 2001). More recently, the Court also rejected a challenge to a subsequent EPA rule withdrawing EPA's findings of significant contribution for Georgia for the 1-hour ozone standard. *See North Carolina* v. *EPA*, 587 F.3d 422 (DC Cir. 2009).

(3) How the NO_X Budget Trading Program (NBP) Worked

The NBP was a market-based cap and trade program created to reduce the regional transport of emissions of NO_X from power plants and other large combustion sources that contribute to ozone nonattainment in the eastern United States. Over six ozone seasons (2003–2008), the NBP significantly lowered NO_X emissions from affected sources, contributing to improvements in regional air quality across the Midwest, Northeast, and Mid-Atlantic. The cap level was intended to protect public health and the environment and to sustain that protection into the future regardless of growth in the affected sector. Ozone season NO_X emissions decreased from levels in baseline years in all states participating in the NBP. (All NBP states transitioned to the CAIR NO_X ozone season program in 2009 except Rhode Island.) Allowance trading was generally active from the start of the program in 2003. Prices and trading were down in 2008, primarily due to uncertainty. Compliance remained virtually 100 percent throughout the program's 6 years. Many nonattainment areas in the East saw substantial improvements in air quality concentrations that brought them in line with ozone NAAQS. The NBP, together with other Federal, State, and local programs, contributed to NO_X reductions that have led to improvements in ozone and $PM_{2.5}$, saving 580–1,800 lives annually in 2008.[11] Changes in ozone and nitrate concentrations due to the NBP have also contributed to improvements in ecosystems in the East.

EPA stopped administering the NBP at the conclusion of 2008 control period activities. States still have the emissions reductions requirement and could use the CAIR NO_X ozone season trading program to achieve this.

See section V.D.4.e. for a discussion of the results of the NO_X Budget Trading Program.

(4) Clean Air Interstate Rule

Following promulgation of the new NAAQS in 1997, the CAA required all states, regardless of whether they have attainment air quality in all areas, to submit SIPs containing provisions specified under section 110(a)(2). In addition, states are required to submit SIPs for nonattainment areas which are generally required to include additional emissions controls providing for attainment of the NAAQS.

As described previously, section 110(a)(2)(D)(i)(I) provides a tool for addressing the problem of transported pollution that significantly contributes to downwind nonattainment and maintenance problems. Under section 110(a)(2)(D), a SIP must contain adequate provisions prohibiting sources in the state from emitting air pollutants in amounts that would contribute significantly to nonattainment or interfere with maintenance in one or more downwind states. Section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet any CAA requirement. If EPA makes such a finding, it is to require the state

[11] U.S.EPA. September, 2009. *The NO_X Budget Trading Program: 2008 Environmental Results,* p.9.

to submit, within a specified period, a SIP revision to correct the inadequacy ("SIP call"). In 1998, EPA used this authority to issue the NO_X SIP Call, discussed previously, to require states to revise their SIPs to include measures to reduce NO_X emissions that were significantly contributing to ozone nonattainment problems in downwind states.

Sulfur dioxide and NO_X are not the only emissions that contribute to interstate transport and $PM_{2.5}$ nonattainment. However, EPA stated in the CAIR that it believed that, given current knowledge, it was not appropriate to specify emissions reductions requirements for direct $PM_{2.5}$ emissions or organic precursors (*e.g.*, volatile organic compounds (VOCs) or ammonia (NH_3)). Similarly, for 8-hour ozone, EPA continued to rely on the conclusion of the OTAG that analysis of interstate transport control opportunities should have focused on NO_X, rather than VOCs. [12]

(5) What is the CAIR?

The CAA contains a number of requirements to address nonattainment of the $PM_{2.5}$ and the 8-hour ozone NAAQS, including requirements that states address interstate transport that significantly contributes to such nonattainment. [13] Based on air quality modeling, ambient air quality data analyses, and cost analyses, EPA found that emissions in certain upwind states resulted in amounts of transported $PM_{2.5}$, ozone, and their emissions precursors that significantly contributed to nonattainment in downwind states.

In the CAIR, promulgated on May 12, 2005 (70 FR 25162), EPA required SIP revisions in 28 states and the District of Columbia, within 18 months after publication of the notice of final rulemaking, to ensure that certain emissions of SO_2 and/or NO_X—important precursors of $PM_{2.5}$ (NO_X and SO_2) and ozone (NO_X)—were prohibited. Achieving the emissions reductions identified, EPA concluded, would address the states' requirements under section 110(a)(2)(D)(i)(I) of the CAA and would help $PM_{2.5}$ and ozone nonattainment areas in the eastern half of the United States attain the standards. Moreover, EPA concluded that such attainment would be achieved in a more certain, equitable, and cost-effective manner than if each nonattainment area attempted to implement local emissions reductions alone, and would also assist the covered states and their neighbors in making progress toward their visibility goals.

The CAIR built on EPA's efforts in the NO_X SIP Call to address interstate pollution transport for ozone, and was EPA's first attempt to address interstate pollution transport for $PM_{2.5}$. It required significant reductions in emissions of SO_2 and NO_X, which contribute to fine particle concentrations. In addition, NO_X emissions contribute to ozone problems. EGUs were found to be a major source of the SO_2 and NO_X emissions which contributed to fine particle concentrations and ozone problems downwind.

CAIR was designed to provide significant air quality attainment, health, and environmental improvements across the eastern U.S. in a highly cost-effective manner by reducing SO_2 and NO_X emissions from EGUs that contribute to the $PM_{2.5}$ and 8-hour ozone problems described in the rule. CAIR's emissions reductions requirements were based on controls that EPA had determined to be highly cost-effective for EGUs under optional cap and trade programs. However, states had the flexibility to choose the measures to adopt to achieve the specified emissions reductions. EPA required the emissions reductions to be implemented in two phases, with the first phase in 2009 and 2010 (for NO_X and SO_2, respectively), and the second phase for both pollutants in 2015. These requirements are described in more detail in section V.D.1.

In addition to promulgating findings of significant contribution to nonattainment, EPA assigned emissions reductions requirements for SO_2 and/or NO_X that each of the identified states must meet through SIP measures.

Section V.D.1 discusses the approach taken in CAIR using three model multi-state cap and trade programs for SO_2 and NO_X that EPA developed and that states could choose to adopt to meet the required emissions reductions in a flexible and cost-effective way.

The requirements in the CAIR were intended to address regional interstate transport of air pollution. EPA recognized, however, that additional local reductions might be necessary to bring some areas into attainment even after significantly contributing upwind emissions were eliminated. 70 FR 25165–66, May 12, 2005. In addition, states that shared an interstate nonattainment area were expected to work together in developing the nonattainment SIP for that area, reducing emissions that contributed to local-scale interstate transport problems.

CAIR FIPs. When EPA promulgated the final CAIR in May 2005, EPA also issued a national finding that states had failed to submit SIPs to address the requirements of CAA section 110(a)(2)(D)(i) with respect to the 1997 ozone and $PM_{2.5}$ NAAQS. States were to have submitted 110(a)(2)(D)(i) SIPs for those standards by July 2000. This action triggered a 2-year clock for EPA to issue FIPs to address interstate transport. On March 15, 2006 the EPA promulgated FIPs to ensure that the emissions reductions required by the CAIR are achieved on schedule. The FIPs did not limit states" flexibility in meeting their CAIR requirements as all states remained free to submit SIPs at any time that, if approved by EPA, would replace the FIP for that state.

As the control strategy for the FIPs, EPA adopted the model cap and trade programs that it provided in the CAIR as a control option for states, with minor changes to account for federal, rather than state, implementation. The FIPs required power plants in affected states to participate in one or more of three separate emissions cap and trade programs that cover: (1) Annual SO_2 emissions, (2) annual NO_X emissions, and (3) ozone season NO_X emissions. Emission cap and trade programs are a proven method for achieving highly cost-effective emissions reductions while providing regulated sources with flexibility in choosing compliance strategies.

The FIPs also provided states with an option to submit abbreviated SIPs to meet CAIR. Under this option, states could save the time and resources needed to develop the complete trading program SIP, while still being able to make key decisions, such as the methodology for allocating annual and/or ozone season NO_X allowances.

New Jersey and Delaware. Separately, on March 15, 2006, EPA issued a final rule to include Delaware and New Jersey in the CAIR to control SO_2 and NO_X emissions because they contribute to $PM_{2.5}$ nonattainment in other states. 71 FR 25288, April 28, 2006. These states were already included in the CAIR because their sources contributed to nonattainment of other states' 8-hour ozone air quality standard. The CAIR FIP established requirements for Delaware and New Jersey with respect to both ambient air quality standards.

(6) Legal Challenges to the CAIR

Petitions for review challenging various aspects of the CAIR were filed in the U.S. Court of Appeals for the DC Circuit. In *North Carolina* v. *EPA,* 531

[12] The OTAG was active from 1995–1997 and consisted of representatives from the 37 states in that region; the District of Columbia; EPA; and interested members of the public, including industry and environmental groups. *See* discussion below under NO_X SIP Call for further information on OTAG.

[13] The term "transport" includes the transport of both $PM_{2.5}$ and their precursor emissions and/or transport of both ozone and its precursor emissions.

F.3d 896, *modified on reh'g* 550 F.3d 1176 (D.C. Cir. 2008), the Court granted several of the petitions for review and remanded the rule to EPA for further proceedings. In its July 2008 opinion, *North Carolina,* 531 F.3d 896, the Court upheld several challenged aspects of EPA's approach, but also found fatal flaws in the rule—flaws it found significant enough to warrant vacatur of the CAIR and the associated FIPs in their entirety. In December 2008, however, the Court responded to petitions for rehearing and determined that "notwithstanding the relative flaws of CAIR, allowing the CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR." *North Carolina,* 550 F.3d at 1178. Accordingly, it decided to remand the rule without vacatur "so that EPA may remedy CAIR's flaws in accordance with [the Court's] July 11, 2008 opinion in this case." *Id.*

Although the entire rule was remanded, important parts of EPA's rulemaking were upheld by the Court in its July 2008 ruling. The Court upheld key aspects of the air quality modeling portion of EPA's significant contribution analysis. It upheld EPA's decision to consider upwind states for inclusion in the CAIR only if those states contributed to projected nonattainment in 2010. *See North Carolina,* 531 F.3d at 913–914. The Court further upheld the contribution threshold used in the air quality modeling portion of the significant contribution analysis for $PM_{2.5}$, EPA's use of whole states as the unit of measurement, and the first-phase NO_X compliance deadline of 2009 *See id.* at 914–17, 923–27, 928–29.

The Court also found significant flaws in EPA's approach. The Court emphasized the importance of individual state contributions to downwind nonattainment areas and held that EPA had failed to adequately measure significant contribution from sources within an individual state to downwind nonattainment areas in other states. *Id.* at 907. Further, the Court noted that EPA had not provided adequate assurance that the trading programs established in the CAIR would achieve, or even make measurable progress towards achieving, the section 110(a)(2)(D)(i)(I) mandate to eliminate significant contribution. *See North Carolina,* 532 F.3d at 907–08. For these reasons, it concluded that EPA had not shown that the CAIR rule would achieve measurable progress towards satisfying the statutory mandate of section 110(a)(2)(D)(i)(I) and thus EPA lacked authority for its action. *See id.* at 908. Moreover, it emphasized that where the rule constitutes a complete 110(a)(2)(D)(i)(I) remedy, it must actually require the elimination of emissions that contribute significantly to nonattainment or interfere with maintenance downwind. *See id.*

The Court further rejected the state budgets for SO_2 and NO_X which were used to implement the CAIR trading programs, finding the budgets to be insufficiently related to the 110(a)(2)(D)(i)(I) mandate of eliminating significant contribution and interference with maintenance. *See id.* at 916–21. It also rejected EPA's effort to harmonize the CAIR SO_2 trading program with the existing requirements of Title IV of the CAA, holding that section 110(a)(2)(D)(i)(I) did not give EPA authority to terminate or limit Title IV allowances. In addition, the Court found that EPA had failed to give meaning to the "interfere with maintenance" prong of section 110(a)(2)(D)(i)(I), that EPA had not demonstrated that the 2015 compliance deadline used in the CAIR was coordinated with the downwind state's deadlines for attaining the NAAQS, and that EPA had not adequately supported its determination that sources in Minnesota significantly contributed to nonattainment or interfered with maintenance in downwind states. *See id.* at 908–11, 911–13, and 926–28.

(7) How the Clean Air Interstate Rule Worked

Building on the emissions reductions under the NBP and Acid Rain Program (ARP), CAIR was designed to permanently lower emissions of SO_2 and NO_X in the eastern United States. As explained previously, although the DC Circuit remanded the rule to EPA, it did so without vacatur allowing the rule to remain in effect while EPA addresses the remand. Thus, CAIR is continuing to help states address ozone and $PM_{2.5}$ nonattainment and improve visibility, reducing transported precursors of SO_2 and NO_X, through the implementation of three separate cap and trade compliance programs for annual NO_X, ozone season NO_X, and annual SO_2 emissions from power plants.

See section V.D.4.e. for a discussion on CAIR implementation in 2009, the first year of the NO_X annual and ozone season programs. The CAIR annual SO_2 program began January 1, 2010. Quarterly emissions will be posted on EPA's web site (*see http://camddataandmaps.epa.gov/gdm/*) and an assessment of emissions reduction data will be available at the end of each compliance period.

C. What are the goals of this proposed rule?

In developing this proposed rule, EPA was guided by a number of goals and guiding principles, as discussed in this section of the preamble.

1. Primary Goals

a. Respond to the Court Remand of the CAIR

Most importantly, this proposal responds to the remand of the CAIR by the Court. As noted previously, the Court granted several petitions for review of the CAIR, finding fatal flaws with the rule; yet, it ultimately decided to remand the rule without vacatur to preserve the environmental benefits of the rule. *North Carolina* v. *EPA,* 531 F.3d 896, *modified on reh'g,* 550 F.3d 1176 (DC Cir. 2008).

The action EPA is proposing would respond to the July and December 2008 opinions of the DC Circuit and correct the flaws in the CAIR methodology that were identified by the Court. The action responds to the Court's concerns in numerous ways. The methodology used to measure each state's significant contribution emphasizes air quality considerations and uses state specific data and information. The methodology also gives independent meaning to the interfere with maintenance prong of section 110(a)(2)(D)(i)(I). The state budgets for SO_2, annual NO_X and ozone season NO_X are directly linked to the measurement of each state's significant contribution and interference with maintenance. The compliance deadlines are coordinated with the attainment deadlines for the relevant NAAQS. And the proposed remedy includes assurance provisions to assure that all necessary reductions occur in each individual state.

The action would also propose FIPs which would replace the remanded CAIR FIPs. The proposed FIPs would apply to all states covered by the rule, including those for which EPA had previously approved SIPs under the remanded CAIR. If finalized as proposed, these FIPs would eliminate or, at a minimum, make measurable progress towards eliminating emissions of SO_2 and NO_X that significantly contribute to or interfere with maintenance of the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS in the eastern half of the United States.

b. Address Transport Requirements With Respect to the Existing $PM_{2.5}$ Standards

This proposed rule is designed to address the requirements of section 110(a)(2)(D)(i)(I) of the CAA as they

relate to the 1997 and 2006 $PM_{2.5}$ standards for states in the eastern United States. The proposed rule would both identify the emissions from states in the eastern U.S. that significantly contribute to nonattainment and interfere with maintenance of the NAAQS in downwind states, and prohibit such emissions.

States are obligated to submit SIPs to EPA addressing the provisions of section 110(a)(2), including the transport provisions of section 110(a)(2)(D)(i)(I), within 3 years of the promulgation of a new or revised NAAQS. For the 1997 NAAQS, these SIPs were due in 2000. On April 25, 2005 (effective May 25, 2005) EPA issued findings that states had failed to submit SIPs to satisfy the requirements of section 110(a)(2)(D)(i) of the Act under the 1997 ozone and $PM_{2.5}$ standards. 70 FR 21147, April 25, 2005. These findings started a 2-year clock for the promulgation of a FIP by EPA unless, prior to that time, each state makes a submission to meet the requirements of 110(a)(2)(D)(i) and EPA approves the submission. This 2-year period expired in May 2007. Because the Court found CAIR inadequate to satisfy the requirements of 110(a)(2)(D)(i)(I), neither EPA's FIP implementing the requirements of CAIR nor any states SIPs that relied on CAIR to satisfy the requirements of this section, are adequate to meet the requirements of section 110(a)(2)(D)(i)(I). EPA's obligation to issue a FIP has therefore not yet been met. The requirements of the FIPs proposed in this rule are designed to address this obligation.

Revisions to the 1997 $PM_{2.5}$ standards were signed by the Administrator on September 21, 2006, and published in the **Federal Register** on October 17, 2006. 71 FR 61144. The revisions were effective December 18, 2006. EPA interprets the 3 year deadline for submission of 110(a)(2) SIPs to be 3 years from the date of signature. Accordingly, for the 2006 revisions to the $PM_{2.5}$ NAAQS, the SIPs under 110(a)(2) were due on September 21, 2009. On June 9, 2010, EPA issued a notice making findings that states had not submitted SIPs under the 2006 $PM_{2.5}$ NAAQS by the September 2009 deadline. 75 FR 32673. These findings started a 2-year clock for the promulgation of a FIP by EPA unless, prior to that time, each state makes a submission to meet the requirements of 110(a)(2)(D)(i)(I) and EPA approves the submission. This 2-year period will expire on July 9, 2012. This proposal is designed to provide FIPs for the 2006 standards to ensure that the 110(a)(2)(D)(i)(I) obligation is fully satisfied as it relates to those standards. EPA also notes that under FIPs, reduction requirements are immediately effective and thus FIPs provide for the most expeditious means to implement emissions reduction requirements.

c. Address Transport Requirements With Respect to the 1997 Ozone Standards

This proposed rule, in concert with other actions, largely eliminates upwind state emissions that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to the 1997 8-hour ozone NAAQS. EPA will issue a subsequent proposal for the 1997 8-hour ozone NAAQS to address fully the requirements of CAA Section 110(a)(2)(D)(i)(I). EPA's goal is to fully address transport requirements for the 1997 ozone standards as soon as possible.

d. Provide for a Smooth Transition From Existing Programs

In addressing the Court remand in a way that satisfies the CAA transport requirements, EPA is also mindful of the need to ensure a smooth transition from the existing requirements. Substantial improvements in air quality have resulted from those requirements with associated health benefits. It is important not to lose those benefits as the new requirements move forward. It is also important to move quickly with those portions of the new requirements that provide the greatest benefits.

2. Key Guiding Principles

a. Appropriately Identify Necessary Upwind Reductions

Emissions from upwind states can, alone or in combination with local emissions, result in air quality levels that exceed the NAAQS and jeopardize the health of residents in downwind communities. Each upwind state is required by the "good neighbor provision" to eliminate its individual significant contribution to downwind state nonattainment and to eliminate emissions that interfere with downwind states" maintenance of the air quality standards. The Act does not require upwind states to eliminate all emissions that affect downwind air quality or shift responsibility for attaining the NAAQS to the upwind states. Instead, the "good neighbor provision" requires each upwind state to, within 3 years of promulgation or revision of a NAAQS, submit a SIP to prohibit those emissions that significantly contribute to nonattainment or interfere with maintenance downwind. The prohibition on these emissions is intended to assist downwind states as they design strategies for ensuring that the NAAQS are attained and maintained.

In practice, it is very complex for individual states to address the transport requirements. Generally for transport of ozone, and for transport of sulfate and nitrate fine particles, each downwind area is affected by emissions from multiple upwind states. In addition, in many cases states are simultaneously both upwind and downwind of one another. Further, only emissions that will significantly contribute to nonattainment or interfere with maintenance in another state are prohibited. Thus, an upwind state's obligations are affected by the air quality downwind. Downwind air quality, in turn, is affected by both local emissions and the cumulative impact of emissions from all of the contributing upwind states.

The problem of interstate transport is thus extremely complex and any remedy must acknowledge the inherent complexity of the problem. It is appropriate for EPA in developing such a remedy to be mindful of the interaction between upwind emissions controls and local emissions controls.

The EPA continues to conclude, as it did in developing the CAIR, that it would be difficult if not impossible for many nonattainment areas to reach attainment through local measures alone, and EPA finds no information developed subsequent to development of CAIR to alter this conclusion. At the time of the proposed CAIR rule, EPA conducted a local measures analysis representing an ambitious set of measures and emissions reductions that may in fact be difficult to achieve in practice. (Ref: Section IX of Technical Support Document for the Interstate Air Quality Rule Air Quality Modeling Analyses, January 2004). This analysis was intended to provide illustrative examples of the nature of location measures and possible reductions. This analysis was not intended to precisely identify local emissions control measures that may be available in a particular area. The EPA continues to believe that a strategy based on adopting cost effective controls on sources of transported pollutants as a first step will produce a more reasonable, equitable, and optimal strategy than one beginning with local controls. The local measures analyses we conducted were not, however, intended to develop a specific or "optimal" regional and local attainment strategy for any given area. Rather, the analysis was intended to evaluate whether, in light of available

local measures, it is likely to be necessary to reduce significant regional transport from upwind states. EPA continues to believe that the two local measures analyses that were conducted for the CAIR strongly support the need for regional reductions of SO_2 and NO_X.

In conclusion, EPA believes that the proposed rule represents the best approach for identifying upwind state emissions that significantly contribute to nonattainment in, or interfere with maintenance by, downwind states.

b. Ensuring That Pollution Controls Operate

The proposed Transport Rule would, by 2012, cap emissions of SO_2 and NO_X on a state-by-state basis and guarantee that existing and planned pollution controls operate. EPA is convinced that the considerable benefits to air quality and public health that have been achieved must be ensured going forward. Keeping emissions of SO_2 and NO_X from increasing by 2012 in 27 states and DC assures that recent gains are maintained and that states that significantly contribute to downwind $PM_{2.5}$ nonattainment and maintenance areas do not increase their contribution to those areas. Further, this proposal would maintain the ozone season emissions reductions achieved since 2005 in 26 states, ensuring that states that significantly contribute to downwind ozone nonattainment and maintenance areas do not increase their contribution to those areas. Tables III.A–2 and III.A–3 in section III.A, previously, show the projected EGU emissions for the 2012 phase of the Transport Rule.

c. Provide Workable Approach for EPA and States

Another important goal in developing the proposed requirements is to provide requirements that can, as a practical matter, be implemented by both EPA and state air quality agencies. Both EPA and state resources are limited and EPA recognizes the importance of developing requirements that make efficient use of limited EPA and state resources. EPA also notes that the air quality improvements brought about by reducing transport can greatly assist states in the development of SIPs and attainment demonstrations.

d. Ensure a Reliable Power Supply

EPA recognizes that requirements for EGUs must be mindful of the variability in the operation of the power grid, and that any requirements for broad reductions should be structured in a way that ensures a reliable power supply.

e. Provide for Cost-Effectiveness

EPA believes that is important to keep both cost-effectiveness and air quality objectives in mind in addressing the CAA transport requirements.

f. Provide Incentives and Flexibility to the Regulated Community

EPA seeks to provide approaches that provide regulated owners/operators of sources with the incentive to achieve all cost-effective reductions. EPA's experience shows that providing this incentive, and the flexibility to seek alternatives to less cost-effective controls, provides for greater environmental protection at reduced cost.

D. Why does this proposed rule focus on the eastern half of the United States?

For this proposal, we identified a 37 state region for the technical analysis, including all states east of the Rockies, from the Dakotas through Texas eastward. Western states also need to address the requirements of section 110(a)(2)(D)(i)(I) of the CAA. However, the transport issues in the eastern United States are analytically distinct and this rule focuses only on that subset of the 110(a)(2)(D)(i)(I) issues.

First, interstate transport of $PM_{2.5}$ and ozone is a substantial and critical component for attaining the ozone and $PM_{2.5}$ NAAQS in the eastern United States. The significant reductions in ambient air pollutant concentrations since CAIR, due largely to the large reductions in transported emissions, only serve to reinforce this point.

Second, in developing the CAIR, EPA found that interstate transport (particularly for anthropogenic emissions) made much smaller contributions to exceedances of the 1997 $PM_{2.5}$ standards in the western United States. At the time, the only exceedances of the 15 $\mu g/m^3$ in those states were in parts of California, and in Lincoln County (Libby), Montana. The Montana location has subsequently come into attainment.

Technical information developed for EPA's recently completed nonattainment designations suggests that interstate emissions transport makes a relatively small contribution to exceedances in the western United States under the 2006 $PM_{2.5}$ standards. For these designations, EPA identified several locations in the western U.S. with exceedances of the 24-hour $PM_{2.5}$ standards. These locations were in California and a few other western states: Alaska, Washington, Oregon, Utah, and Arizona. Technical support information describing the nature of the 24-hour $PM_{2.5}$ problem at each of these locations is available at: *http://www.epa.gov/pmdesignations/2006standards/tech.htm.* A review of this information suggests to EPA that the Western nonattainment problems are relatively local in nature with limited interstate transport. EPA requests comment on this assessment.

E. Anticipated Rules Affecting Power Sector

On January 12, 2010, the EPA Administrator outlined seven priorities for the Agency. One of them is to improve air quality. In her description of this priority she said, "EPA will develop a comprehensive strategy for a cleaner and more efficient power sector, with strong but achievable reduction goals for SO_2, NO_X, mercury, and other air toxics." In furtherance of this priority goal, and to respond to statutory and judicial mandates, EPA is undertaking a series of regulatory actions over the course of the next 2 years that will affect the power sector in particular.

The rules under the CAA will substantially reduce the emissions of SO_2, NO_X, mercury, and other air toxics. To the extent that the Agency has the legal authority to do so while fulfilling its obligations under the Act and other relevant statutes, the Agency will also coordinate these utility-related air pollution rules with upcoming regulations for the power sector from EPA's Office of Water (OW) and its Office of Resource Conservation and Recovery (ORCR). EPA expects that this comprehensive set of requirements will yield substantial health and environmental benefits for the public, benefits that can be achieved while maintaining a reliable and affordable supply of electric power across the economy. In developing and promulgating these rules, the Agency will be providing the power industry with a much clearer picture of what EPA will require of it in the next decade. In addition to promulgating the rules themselves, the Agency will engage with other federal, state and local authorities, as well as with stakeholders and the public at large, with the goal of fostering investments in compliance that represent the most efficient and forward-looking expenditure of investor, shareholder, and public funds, resulting, in turn, in the creation of a clean, efficient, and completely modern power sector.

The major CAA rules that will drive these compliance investments are: (1) This transport rule; (2) potential future rules that may be needed to address transport under future revised ozone or fine particle health standards; (3) the

CAA Section 112(d) standards; (4) revisions to the NSPS for coal and oil-fired electric utility steam generating units; and (5) BART requirements and other requirements that address visibility and regional haze. Within the planning and investment horizon for compliance with these rules, the EPA very likely will be compelled to respond a pending petition to set standards for the emissions of greenhouse gases from steam electric generating units under the NSPS program. Furthermore, as set forth in the recently promulgated reinterpretation of the Johnson Memo, beginning in 2011 new and modified sources of GHG emissions, including EGUs, will be subject to permits under the Prevention of Significant Deterioration program requiring them to adopt BACT for their GHGs. Finally, EPA will also pursue with other federal agencies, states, and other groups energy efficiency improvements in the use of electricity throughout the economy that will contribute to additional environmental and public health improvements that the Agency wants to provide while lowering the costs of realizing those improvements.

A brief explanation of these major CAA rulemakings and activities follows.

Transport Rule. This proposed transport rule includes emissions reductions requirements for EGUs to address interstate transport under the 1997 ozone NAAQS, the 1997 $PM_{2.5}$ NAAQS, and the 2006 $PM_{2.5}$ NAAQS. After considering public comments on this proposal, EPA will endeavor to issue a final rule in spring 2011.

Rules to Address Transport under Revised Air Quality Health Standards. EPA currently is reconsidering its 2008 national ambient air quality standards for ozone, and is conducting a periodic review of the particulate matter NAAQS, including the fine particle standards. The Act requires EPA to ensure that primary standards are requisite to protect public health with an adequate margin of safety, and to set secondary standards requisite to protect public welfare. The Act requires EPA to review, and revise if appropriate, the primary and secondary NAAQS on a 5-year schedule to ensure that air quality standards reflect the latest scientific information on health and welfare effects. When air quality standards are set or revised, the Act requires revision of SIPs to ensure that these standards to protect public health and welfare are met expeditiously and, in the case of the health-based standards, within timetables in the Act.

If more protective NAAQS are promulgated, further emissions reductions would likely be needed in states where pollution levels exceed air quality standards, and in upwind states with emissions that significantly contribute to the air quality problems in another state. This may result in additional emission reduction requirements for facilities in the power sector, as well as for other sectors. The reconsideration of the March 2008 ozone air quality standards will be completed soon, and the review of particulate matter air quality standards by October 2011. SIP deadlines and attainment deadlines would flow from those dates.

EPA plans to make expeditious determinations of upwind state emissions reduction responsibilities for NAAQS for which interstate transport is an issue. This approach will lead to earlier emissions reductions to protect public health, as well as provide other benefits. In the *North Carolina* decision, the court made clear that downwind state nonattainment deadlines are legally relevant to the timing of reductions under section 110(a)(2)(D). Thus, expeditious determinations of upwind state responsibilities under section 110(a)(2)(D) can promote upwind reductions in time to help downwind states meet attainment deadlines, enable states and EPA to provide sources with earlier information on their emission reduction responsibilities, and maximize sources lead time to reduce emissions.

If a more protective ozone NAAQS is issued in August, EPA would plan to propose an interstate pollution transport rule for that NAAQS in 2011. We would expect work on that proposal to proceed in parallel with efforts to finalize this Transport Rule for the 1997 and 2006 NAAQS. A final rule to address interstate pollution transport for a reconsidered ozone NAAQS would be anticipated in 2012. In view of the implementation schedule for a reconsidered ozone NAAQS, compliance dates would be later than the compliance dates proposed for this Transport Rule, and would take into account attainment dates for that NAAQS and other factors such, as control cost and installation time. For any revised $PM_{2.5}$ NAAQS, EPA plans to conduct a similarly expeditious analysis of interstate transport to support a determination as to whether or not further emissions reductions from the power sector are required under section 110(a)(2)(D), in light of the emissions reductions required by other power sector rules.

A revised SO_2 NAAQS was issued on June 2 creating a new 1-hour SO_2 NAAQS which, when implemented, will protect Americans from asthma and respiratory difficulties associated with short term exposures to SO_2. Although EPA does not expect peak SO_2 levels to be a long-range transport issue, power plants are among the sources that can contribute to peak SO_2 levels and will likely be evaluated by states as they consider control measures to attain the new standards. Anticipated emissions reductions from power plants and other SO_2 sources under other Clean Air Act (CAA or Act) requirements (*e.g.*, transport rules, and MACT standards) are expected to play a significant role in attainment of the 1-hour SO_2 NAAQS.

Section 112(d) Standards for Utility Units. In 2008, the DC Circuit Court vacated the CAMR and the 112(n) Revision Rule, which removed coal- and oil-fired electric utility steam generating units from the section 112(c) list of sources subject to regulation. EPA is in the early stages of developing regulations under section 112 of the CAA that will require existing and new coal- and oil-fired utility units to meet emissions limits for mercury and other HAPs emitted from these sources. As required by section 112, EPA will issue a set of emissions standards. In part, the section 112(d) rule will require that all existing major sources achieve the emission limits for HAPs which will be at least as stringent as the average emissions reduction currently achieved by the best performing 12 percent of these units. Additionally, any new major source will be required to meet emission limits that are at least as stringent as what is currently achieved by the best-performing single source. Currently, the Agency is seeking data on five categories of HAP emissions: (1) Acid gases (*e.g.*, hydrochloric acid, hydrogen fluoride, and hydrogen cyanide); (2) mercury; (3) Non-Hg metals (*e.g.*, lead, cadmium, selenium, and arsenic); (4) dioxins/furans; and, (5) other organic hazardous air pollutants. EPA expects to receive the requested data, including stack testing results, by September 2010. EPA has agreed to sign the proposed rule by March 16, 2011, and sign the final rule no later than November 16, 2011. EPA may provide existing sources up to 3 years to comply with section 112(d) standards, and the CAA authorizes the permit authority to grant a 1 year extension of the compliance date on a case-by-case basis if such extension is necessary for the installation of controls. The CAA requires new sources to comply on the effective date of the final rule or at startup, whichever is later. If EPA were to provide 3 years for compliance with the section 112(d) standards,

compliance would generally be required by early 2015.

In developing these rules, EPA will endeavor to proceed in a way that provides all stakeholders and other Federal, State and local decision-makers with ongoing, up-to-date information about the full suite of environmental responsibilities that the power sector must undertake. This, in turn, will enable power companies and others whose policies and decisions affect their investment choice to adopt compliance strategies that take full advantage of co-control opportunities and efficiencies and other approaches to maximizing the cost-effectiveness and leveraging benefits of their investments.

New Source Performance Standards. NSPS are administered under section 111 of the CAA. The standards for new, modified, and reconstructed steam EGUs are contained in 40 CFR part 60 subpart Da, which was last amended in 2006. The current structure of subpart Da sets output-based (*i.e.*, lbs of emission/MWh) emission limits for NO_X and SO_2 and optional output-based standards for particulate matter. EPA is currently re-evaluating the standards in Subpart Da to determine whether they reflect the degree of emission limitation achievable through the application of the best system of emission reduction, which the Administrator determines has been adequately demonstrated. EPA also has a pending voluntary remand to decide whether NSPS standards for this source category should include limits on GHG emissions. EPA is considering the timetable for these actions and decisions in light of legal obligations and policy considerations, including the desirability of the industry knowing its regulatory obligations to inform investment decisions.

Regional Haze/BART. States are required to develop SIPs that address regional haze in scenic areas such as national parks and wilderness areas. EPA regulations for regional haze appear in Chapter 40 of the CFR in sections 51.308 and 51.309. One of the requirements of the regional haze SIPs is to provide for BART for large industrial sources including EGUs. The BART provisions affect EGUs put into operation between 1962 and 1977.

Energy Efficiency. Policies that will promote efficient use of electric power can be an integral, highly cost-effective component of power companies" compliance strategies. Reducing demand for electricity can in itself achieve large emissions reductions and public health benefits, while enhancing the reliability of the grid. It can also lower the cost of emissions reductions for consumers of electricity and for the power industry, as investments are avoided in unnecessary infrastructure.

EPA does not have sole responsibility for the development of energy policy to promote efficiency. To facilitate this component of the power sector's compliance strategy, EPA intends to engage with other federal, state, and local agencies whose policies and actions can make it easier for power companies to adopt, or benefit from, energy efficiency investments in their compliance strategies. EPA will continue to use its authorities to advance energy efficiency by providing incentives for energy efficiency in our regulatory programs (*e.g.*, output-based standards) and through our successful existing voluntary programs such as ENERGY STAR. The Department of Energy (DOE) also has considerable resources to encourage efficient use of electricity. Additional resources have been made available under the American Recovery and Reinvestment Act to both DOE and EPA to promote energy efficiency. State governments, both in their environmental programs and through their public service commissions, which regulate electric utility rates, can promote energy efficiency. Many state governments have been leaders in promoting efficient use of electricity through such mechanisms as energy efficiency standards and demand response, and EPA and DOE are assisting state governments in this effort. Local governments as well, through building codes, zoning, and other actions, can and do promote end-use energy efficiency. The Federal Energy Regulatory Commission (FERC) regulates wholesale electricity markets and sets mandatory reliability standards to assure a safe reliable power system. In carrying out this mission FERC recognizes that energy efficiency is a resource, to be considered along with other energy resources in reliability and economic planning.

All of these entities will need to work in concert to achieve a truly efficient, reliable, cost-effective electric power system. EPA is committed to meeting this challenge.

Non-Air Office Regulations. EPA is also working on three additional rules that will have potential impacts on the power sector. The Office of Solid Waste and Emergency Response is developing revised regulations for coal combustion residues, which are the combustion byproducts associated with the use of coal as a fuel. The Administrator signed the proposed rule on May 4, 2010. Over the next few years, EPA's Office of Water plans to develop two rules affecting electric generating units; the precise timing of these rules is being determined. One will regulate cooling water intake structures. The other will revise the effluent guidelines for wastewater discharges from power plants. Each of these rules has cost implications to the power sector, and the Agency intends to coordinate these regulations with the upcoming air regulations. We intend to maximize reductions in pollution while maintaining cost-effective solutions.

As a first step to carrying out its commitment to promote and facilitate the most cost-effective and forward-looking compliance investments and strategies on the part of the power sector, EPA will conduct extensive outreach concerning the full range of the upcoming environmental responsibilities of the sector as it proposes the Transport Rule. Upon this proposal, the Agency will begin an outreach effort with the public, the regulated community, state air regulators, and others to (1) describe the Transport Rule proposal, and (2) provide information on the 2011 section 112 standards for utility units and other upcoming EPA rulemakings affecting the power sector. The intent will be to inform all stakeholders of the industry's obligations and opportunities for the industry to use investments in SO_2 and NO_X reductions to help smooth transition to compliance with the Section 112(d) standards applicable to utility units.

At the same time EPA also intends to expand its outreach to others—who can play a significant role in promoting or requiring investment in energy efficiency. EPA intends to continue these efforts over time as more information becomes available in the development of the various rulemakings under development for the power sector.

IV. Defining "Significant Contribution" and "Interference With Maintenance"

This section describes EPA's proposed approach to define emissions that significantly contribute to nonattainment or interfere with maintenance of the $PM_{2.5}$ and ozone NAAQS downwind. The section begins by providing background on how "significant contribution" and "interference with maintenance" were defined in the past by EPA for the NO_X SIP Call and the CAIR, describing past Court opinions on EPA's approach, and presenting an overview of EPA's proposed Transport Rule approach (section IV.A). Next, section IV.B describes the proposed approach to identify upwind contributing states. Section IV.C details the air quality modeling approach and results used for

this proposed rule. Section IV.D provides a detailed description of EPA's proposed approach to quantify emissions that significantly contribute and interfere with maintenance. Section IV.E includes proposed state emissions budgets before accounting for the inherent variability in power system operations. Section IV.F discusses the inherent variability in power system operations, proposes variability limits on the state budgets, and presents projected emissions reduction results. Section IV.G describes how the proposed approach is consistent with judicial opinions. Finally, section IV.H lists alternative approaches to defining significant contribution and interference with maintenance that EPA evaluated but is not proposing.

A. Background

1. Approach Used in NO_X SIP Call and the CAIR

a. Significant Contribution

Two rules EPA promulgated that address interstate transport of pollutants are the NO_X SIP Call (63 FR 57356; October 27, 1998) and the CAIR (70 FR 25162; May 12, 2005), which are described in section III.B. In both of these rules, EPA used a 2-step approach to quantify significant contribution. The approaches used in both rules were similar.

In the first step, EPA applied an air quality threshold to determine a set of upwind states whose potential for significant contribution should be evaluated further. That is, EPA compared the contributions that individual upwind states make to downwind receptors and identified states whose contributions were greater than the specified threshold amount. EPA referred to these states as significant contributors but did not rely on this first step to quantify or measure the states' significant contribution.

In the second step, EPA determined the quantity of emissions that the states collectively could remove using highly cost-effective controls. EPA defined this quantity of emissions as the "significant contribution." The approach used in each rule is described in more detail, later.

NO_X SIP Call. EPA addressed the section 110(a)(2)(D)(i)(I) requirement to prohibit emissions that significantly contribute to downwind nonattainment in the NO_X SIP Call. To do so, EPA developed a methodology for identifying emissions that constitute upwind states' "significant contribution." EPA determined that emissions "contribute" to nonattainment downwind if they have an impact on nonattainment downwind (62 FR 60325). EPA established several criteria or factors for the "significant contribution" test (and further indicated that the same criteria should apply to the "interfere with maintenance" provision).[14]

EPA determined the amount of emissions that significantly contribute to downwind nonattainment from sources in a particular upwind state by: (i) Evaluating, with respect to each upwind state, several air quality related factors, including determining that all emissions from the state have a sufficiently great impact downwind (in the context of the collective contribution nature of the ozone problem); and (ii) determining the amount of that state's emissions that can be eliminated through the application of cost-effective controls (63 FR 57403).

Air Quality Factor. The first factor that EPA used to determine the amount of emissions that significantly contribute to downwind nonattainment was the air quality factor, consisting of an evaluation of the impact on downwind air quality of the upwind state's emissions.

EPA specifically considered three air quality factors with respect to each upwind state:

- The overall nature of the ozone problem (*i.e.*, "collective contribution");
- The extent of the downwind nonattainment problems to which the upwind state's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas; and
- The ambient impact of the emissions from the upwind state's sources on the downwind nonattainment problems (63 FR 57376).

EPA explained the first factor, collective contribution, by noting,

> [V]irtually every nonattainment problem is caused by numerous sources over a wide geographic area * * * [. This] factor suggest[s] that the solution to the problem is the implementation over a wide area of controls on many sources, each of which may have a small or immeasurable ambient impact by itself (63 FR 57377).

The second air quality factor is the extent of downwind nonattainment problems. EPA considered the then-current air quality of the area, the predicted future air quality (assuming implementation of required controls but not the transport requirements that were the subject of the NO_X SIP Call), and, when air quality designations had already been made, the boundaries of the area in light of designation status (63 FR 57377).[15]

EPA applied the third air quality factor by projecting the amount of the upwind state's entire inventory of anthropogenic emissions to the year 2007, and then quantifying the impact of those emissions on downwind nonattainment through the appropriate air quality modeling techniques.[16] Specifically, (i) EPA determined the minimum threshold impact that the upwind state's emissions must have on a downwind nonattainment area to be considered potentially to contribute significantly to nonattainment; and then (ii) for states with impacts above that threshold, EPA developed a set of metrics for further evaluating the contribution of the upwind state's emissions on a downwind nonattainment area (63 FR 57378). EPA referred to states with emissions that had a sufficiently great impact as significant contributors; however, the precise amount of their significant contribution was not calculated until the next step. Because the ozone problem is caused by many relatively small contributions, even relatively small contributors must participate in the solution. For this reason, EPA determined that even a relatively small contribution can be significant contribution given the nature of the problem, and established relatively low thresholds.

Cost Factor. The cost factor is the second major factor that EPA applied to determine the significant contribution to nonattainment: "EPA* * * determined whether any amounts of the NO_X emissions may be eliminated through controls that, on a cost-per-ton basis, may be considered to be highly cost effective" (63 FR 57377). Applying this cost factor on top of the air quality factor, EPA determined that emissions that both were from states that exceeded

[14] In the NO_X SIP Call, because the same criteria applied, the discussion of the "contribute significantly to nonattainment" test generally also applied to the "interfere with maintenance" test. However, in the NO_X SIP Call, EPA stated that the "interfere with maintenance" test applied with respect to only the 8-hour ozone NAAQS (63 FR 57379–80).

[15] EPA explained in the NO_X SIP Call, "It should be reiterated that EPA relied on the designated area solely as a proxy to determine which areas have air quality in nonattainment. This proxy is readily available under the 1-hour NAAQS because areas have long been designated nonattainment. The EPA's reliance on designated nonattainment areas for purposes of the 1-hour NAAQS does not indicate that the reference in section 110(a)(2)(D)(i)(I) to "nonattainment" should be interpreted to refer to areas designated nonattainment." (63 FR 57375, footnote 25)

[16] Although EPA's air quality modeling techniques examined all of the upwind state's emissions of ozone precursors (including VOC and NO_X), only the NO_X emissions had meaningful interstate impacts.

the air quality thresholds and could be eliminated through the application of highly cost-effective controls constituted a given state's significant contribution.

Choice of Highly Cost-Effective Standard. EPA chose the standard of "highly cost-effective" in order to assure state flexibility in selecting control strategies to meet the emissions reduction requirements of the rulemaking. That is, the rulemaking required the states to achieve specified levels of emissions reductions—the levels achievable if states implemented the control strategies that EPA identified as highly cost-effective—but the rulemaking did not mandate those highly cost-effective control strategies, or any other control strategy. Indeed, in calculating the amount of the required emissions reductions by assuming the implementation of highly cost-effective control strategies, EPA assured that other control strategies—ones that were cost-effective, if not highly cost-effective—remained available to the states.

Determination of Highly Cost-Effective Amount. EPA determined the dollar amount considered to be highly cost-effective by reference to the cost-effectiveness of recently promulgated or proposed NO_X controls. EPA determined that the average cost-effectiveness of controls ranged up to approximately $1,800 per ton of NO_X removed (1990$) on an annual basis. The EPA considered the controls in the reference list to be cost-effective.

EPA established $2,000 per ton (1990$) in average cost-effectiveness for summer ozone season emissions reductions as, at least directionally, the highly cost-effective amount. Identifying this amount on an ozone season basis was appropriate because the NO_X SIP Call concerned the ozone standard, for which emissions reductions during only the summer ozone season are necessary. In determining the highly cost-effective amount, EPA analyzed costs on a regionwide basis, and assumed a cap and trade program for EGUs and large non-EGU boilers and turbines.

Source Categories. EPA then determined that the source categories for which highly cost-effective controls were available included EGUs, large industrial boilers and turbines, and cement kilns. At the same time, EPA determined, for those source categories, the level of emissions reductions in each state that would result from the application of all controls that would be highly cost-effective and that would be feasible. The EPA considered other source categories, but found that highly cost-effective controls were not available for various reasons, including the size of the sources, the relatively small amount of emissions from the sources, or the control costs.

Other Factors. EPA also relied on several other, secondary considerations to identify the required amount of emissions reductions. The first concerned the consistency of regional reductions with downwind attainment needs. The second general consideration was "the overall fairness of the control regimes" to which the downwind and upwind areas were subject. The third general consideration was "general cost considerations." The EPA noted that "in general, areas that currently have, or that in the past have had, nonattainment problems * * * have already incurred ozone control costs." The next set of controls available to these nonattainment areas would be more expensive than the controls available to the upwind areas. The EPA found that this cost scenario further confirmed the reasonableness of the upwind control obligations (63 FR 57379).

In the NO_X SIP Call, EPA considered all of these factors together in determining the level of controls considered to be highly cost-effective. Within the region, the nonattainment areas already had implemented required VOC and NO_X controls that covered much of their inventory. However, the upwind states in the region generally had not implemented such controls (except as needed to address their ozone nonattainment areas). In this context, EPA considered it reasonable to impose an additional control burden on the upwind states. Air quality modeling showed that residual nonattainment remained even with this additional level of upwind controls so that further reductions from downwind and/or upwind areas would be necessary.

After ascertaining the controls that qualified as highly cost-effective, EPA developed a methodology for calculating the amount of NO_X emissions that each state was required to reduce on grounds that those emissions contribute significantly to nonattainment downwind. The total amount of required NO_X emissions reductions was the sum of the amounts that would be reduced by application of highly cost-effective controls to each of the source categories for which EPA determined that such controls were available (63 FR 57378).

Electric Generating Units. The largest of the source categories discussed previously was EGUs. EPA determined the amount of reductions associated with EGU controls by applying the control rate that EPA considered to reflect highly cost-effective controls to each state's EGU heat input (adjusted for projected growth) (70 FR 25173.) In the NO_X SIP Call, EPA evaluated the costs of control on a region-wide basis.

CAIR. In the CAIR, EPA again addressed the section 110(a)(2)(D)(i)(I) requirement to prohibit emissions that significantly contribute to downwind nonattainment (70 FR 25162). While the NO_X SIP Call had addressed significant contribution with respect to the 1997 ozone NAAQS, the CAIR addressed significant contribution with respect to both the ozone and annual $PM_{2.5}$ NAAQS promulgated in 1997. In the CAIR, EPA used a methodology to identify states" significant contribution based on and very similar to the methodology used in the NO_X SIP Call.

To quantify the amounts of emissions that contribute significantly to nonattainment, EPA explained in the CAIR that the Agency primarily focused on the air quality factor reflecting the upwind state's ambient impact on downwind nonattainment areas, and the cost factor of highly cost-effective controls. *See* 70 FR 25174.

Air Quality Factor—$PM_{2.5}$. EPA employed air quality modeling techniques to assess the impact of each upwind state's entire inventory of anthropogenic SO_2 and NO_X emissions on downwind nonattainment and maintenance for the annual $PM_{2.5}$ NAAQS.[17] EPA determined that upwind NO_X and SO_2 emissions contribute significantly to annual $PM_{2.5}$ nonattainment as of the year 2010.

As in the NO_X SIP Call, EPA used a 2-step approach to quantify significant contribution. In the CAIR, in the first step EPA adopted a threshold air quality impact of 0.2 μg/m3 for $PM_{2.5}$. An upwind state with contributions to downwind nonattainment below this level would not be subject to regulatory requirements, but a state with contributions at or higher than this level would be subject to further evaluation (70 FR 25174–75).

This level reflects the fact that $PM_{2.5}$ nonattainment, like ozone, is caused by many sources in a broad region and therefore may be solved only by controlling sources throughout the region. As with the NO_X SIP Call, the collective contribution condition of $PM_{2.5}$ air quality is reflected in the relatively low threshold (70 FR 25175).

Air Quality Factor—8-Hour Ozone. EPA employed air quality modeling techniques to assess the impact of each upwind state's inventory of NO_X and VOC emissions on downwind nonattainment. The EPA determined

[17] EPA did not address 24-hour $PM_{2.5}$ NAAQS in CAIR, only the annual $PM_{2.5}$ NAAQS.

that upwind NO_X emissions contribute significantly to 8-hour ozone nonattainment as of the year 2010. Therefore, EPA projected NO_X emissions to the year 2010, assuming certain required controls (but not controls required under the CAIR), and then modeled the impact of those projected emissions on downwind 8-hour ozone nonattainment in that year (70 FR 25175).

EPA used the same threshold amounts and metrics for 8-hour ozone that it used in the NO_X SIP Call. That is, emissions from an upwind state were found to contribute significantly to nonattainment if the maximum contribution was at least 2 parts per billion, the average contribution greater than one percent, and certain other numerical criteria were met. EPA also evaluated frequency, magnitude, and relative amounts of contribution to determine which linkages were significant before costs were considered.

Cost Factor. The second step in the 2-step process is to apply the cost factor. As in the NO_X SIP Call, EPA interpreted this factor as mandating emissions reductions in amounts that would result from application of highly cost-effective controls. In the CAIR, EPA determined the level of costs that would be highly cost-effective on a regional basis by reference to the cost effectiveness of other recent controls. EPA concluded that EGUs were the only source category for which highly cost-effective SO_2 and NO_X controls were available at the time. EPA determined as highly cost-effective the dollar amount of cost-effectiveness that falls near the low end of a reference range of control costs. See 70 FR 25175. In the CAIR, as in the NO_X SIP Call, EPA analyzed the costs of control on a regionwide basis.

Other Factors. As with the NO_X SIP Call, EPA considered other factors that influence the application of the air quality and cost factors, and that confirm the conclusions concerning the amounts of emissions that upwind states must eliminate as contributing significantly to downwind nonattainment. See 70 FR 25175.

b. Interference With Maintenance

Section 110(a)(2)(D)(i)(I) requires that SIPs for national primary and secondary air quality standards contain adequate provisions prohibiting emissions in amounts that "interfere with maintenance by any other state" of any such standard.

In the NO_X SIP Call and in the CAIR, EPA gave the term "interfere with maintenance" a meaning much the same as the meaning given to the term "significant contribution." That approach, which was found inconsistent with the requirements of 110(a)(2)(D)(i)(I), is described later. EPA's proposed new approach to interpreting "interfere with maintenance" is described in section IV.D, later.

NO_X SIP Call: In the NO_X SIP Call, EPA explained its approach as follows (63 FR 57379–80):

> After an area has reached attainment of the 8-hour NAAQS, that area is obligated to maintain that NAAQS. (See sections 110(a)(1) and 175A.) Emissions from sources in an upwind area may interfere with that maintenance. The EPA proposes to apply much the same approach in analyzing the first component of the "interfere-with-maintenance" issue, which is identifying the downwind areas whose maintenance of the NAAQS may suffer interference due to upwind emissions. The EPA has analyzed the "interfere-with-maintenance" issue for the 8-hour NAAQS by examining areas whose current air quality is monitored as attaining the 8-hour NAAQS [or which have no current air quality monitoring], but for which air quality modeling shows nonattainment in the year 2007. This result is projected to occur, notwithstanding the imposition of certain controls required under the CAA, because of projected increases in emissions due to growth in emissions generating activity. Under these circumstances, emissions from upwind areas may interfere with the downwind area's ability to attain. Ascertaining the impact on the downwind area's air quality of the upwind area's emissions aids in determining whether the upwind emissions interfere with maintenance (62 FR 60326).
>
> In today's action, EPA is taking the same positions with respect to the interfere-with-maintenance test as described in the notice of proposed rulemaking.

In addition, the NO_X SIP Call preamble stated:

> This [interfere-with-maintenance] requirement * * * does not, by its terms, incorporate the qualifier of "significantly." Even so, EPA believes that for present purposes, the term "interfere" should be interpreted much the same as the term "contribute significantly," that is, through the same weight-of-evidence approach.

CAIR: In the CAIR, EPA also interpreted "interfere with maintenance" in a limited way. EPA only considered whether upwind state emissions eventually posed a maintenance problem for areas that EPA projected to be in nonattainment in 2010 (the year that was the focus of the analysis of significant contribution to nonattainment). EPA did not examine whether areas in attainment in 2010 might face a maintenance problem either in 2010 or thereafter, so no upwind state controls were considered to assist such areas with maintaining clean air. The CAIR preamble stated (70 FR 25193, footnote 45), "we believe the 'interfere with maintenance' prong may come into play only in circumstances where EPA or the state can reasonably determine or project, based on available data, that an [nonattainment] area in a downwind state will achieve attainment, but due to emissions growth or other relevant factors is likely to fall back into nonattainment." [18]

In responding to comments on the CAIR proposal, we also used this interpretation of the maintenance provision to help support the need for Phase II CAIR reductions. For ozone, we conducted an analysis that looked at (1) the amount by which receptor locations were projected to attain in 2015 and (2) the year-to-year variability in ozone levels due to weather and other factors based on a review of historical monitoring data. This analysis concluded that areas within 3–5 ppb of the standard, and sometimes greater (*e.g.*, Fulton County, Atlanta) had historic variability as great as 8 ppb, and that this variability suggests strongly that upwind states could be interfering with maintenance even if modeling shows attainment by up to these amounts. For $PM_{2.5}$, while we lacked historical data to support the same variability analysis, we characterized attaining the annual standard by 0.5 µg/m3 as "attaining by a narrow margin" thus giving rise to maintenance concerns, and noted that in past (mobile source) rules we had indicated that attainment by a margin of 10 percent or less could be considered to raise maintenance concerns.

2. Judicial Opinions

a. Significant Contribution

In *North Carolina* v. *EPA,* 531 F.3d. 896 (DC Cir. 2008), the Court held that the approach EPA used in CAIR to measure each state's significant contribution was insufficient. EPA, the Court concluded, had failed to "measure[ ] the significant contribution from sources within an individual state to downwind nonattainment areas." *Id.* at 907. The Court further reasoned that the lack of a state-specific significant contribution analysis made it impossible for EPA to show that the

[18] The CAIR final preamble stated: "EPA has evaluated the attainment status of the downwind receptors in 2010 and 2015, and has determined that each upwind state's 2010 and 2015 emissions reductions are necessary to the extent required by the rule because a downwind receptor linked to that upwind state will either (i) remain in nonattainment and continue to experience significant contribution to nonattainment from the upwind state's emissions; or (ii) attain the relevant NAAQS but later revert to nonattainment due, for example, to continued growth of the emissions inventory."

trading programs and state budgets established to implement the trading programs, effectuated the section 110(a)(2)(D)(i)(I) statutory mandate to eliminate emissions within the state that significantly contribute to nonattainment or interfere with maintenance in other states.

Specifically, the court rejected the regional scope of EPA's analysis. It reasoned that "because EPA evaluated whether its proposed emissions were 'highly cost effective' at the regionwide level assuming a trading program, it never measured the 'significant contribution' from sources within an individual state to downwind nonattainment areas." *Id.* at 907. In reaching this conclusion, however, the Court also recognized that aspects of EPA's methodology for analyzing significant contribution had been upheld in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), and it left those holdings undisturbed. Specifically, the Court acknowledged its prior conclusion that "significance may include cost" *North Carolina,* 531 F.3d at 919 (citing *Michigan* 213 F.3d 677–79), and thus it is acceptable for EPA to use cost to "draw the 'significant contribution' line". *Id.* The Court also recognized that *Michigan* approved EPA's decision to apply a uniform emissions control requirement to all upwind states despite different levels of contribution. *See North Carolina,* 531 F.3d at 908. The Court thus concluded that while EPA must "measure each state's 'significant contribution' to downwind nonattainment" that measurement need not "directly correlate with each state's individualized air quality impact on downwind nonattainment relative to other upwind states." *Id.* at 908.

In *North Carolina,* the Court also upheld several aspects of the air quality modeling EPA used in the significant contribution analysis. It upheld EPA's use of whole state modeling, *see id.* at 923–26, and deferred to EPA's selection of the $PM_{2.5}$ contribution threshold, *see id.* at 914–15. With regard to EPA's application of the methodology to individual states, the Court found that EPA had failed to respond to comments by Minnesota Power alleging errors in the application of this methodology to determine Minnesota's contribution to downwind $PM_{2.5}$ nonattainment areas. *See id.* at 926–28.

b. Interference With Maintenance

In the CAIR case, the Court also rejected EPA's approach to the second prong of section 110(a)(2)(D)(i)(I), holding that EPA's failure to give independent meaning to the term "interfere with maintenance" was inconsistent with the statutory mandate. *See North Carolina,* 531 F.3d at 910. The Court rejected the approach used in CAIR reasoning that it "provides no protection for downwind areas that, despite EPA's predictions, still find themselves struggling to meet NAAQS due to upwind interference in 2010." *Id.* at 910–11.

3. Overview of Proposed Approach

In this section, EPA will explain how it proposes to identify which states are significantly contributing to downwind non-attainment and/or interfering with maintenance of the NAAQS at downwind sites and to quantify what that contribution is.

In this action, EPA is proposing to use a two step approach to measuring each state's significant contribution. The methodology used is based on the approach used in CAIR and the NO_X SIP Call but modified to address the concerns raised by the Court. In the first step of this proposed approach, EPA uses air quality modeling to quantify individual states' contributions to downwind nonattainment and maintenance sites in 2012. States whose contributions to any downwind sites are greater than 1 percent of the relevant NAAQS are considered "linked" to those sites for the purpose of the second step in the analysis. In the second step, EPA identifies the portion of each state's contribution that constitutes its "significant contribution" and "interference with maintenance." To do so, EPA uses maximum cost thresholds, informed by air quality considerations. Specifically, for each precursor pollutant (*i.e.*, SO_2 and NO_X for $PM_{2.5}$ and NO_X for ozone) emitted by the upwind states that EPA has identified as linked to NAAQS nonattainment and maintenance sites downwind, EPA identifies, through this process, the reductions available from EGUs in each individual upwind state at the appropriate maximum cost threshold. These emissions reductions are the amount of the upwind state's significant contribution. The cost thresholds used in this portion of the analysis, in contrast to the thresholds used in CAIR and the NO_X SIP Call, are informed by air quality considerations, in addition to a comparison of the cost of control in other regulatory contexts. Specific cost thresholds were developed for annual SO_2, annual NO_X, and ozone-season NO_X. Where appropriate, EPA developed higher and lower cost thresholds, based on the downwind air quality impact of emissions from different groups of states. Although EPA in the past has applied a uniform remedy to all states found to have a significant contribution, in this proposal EPA divides, for individual pollutants, the significantly contributing states into two groups: Those whose significant contribution can be eliminated at a lower cost threshold; and those whose significant contribution is not eliminated (to the extent that it has been identified in this proposal) until they reach the higher cost threshold. The lower cost threshold applies to a state if the reduction in emissions at that threshold eliminates nonattainment and maintenance problems at all "linked" sites.

EPA considers that the maintenance concept has two components: Year-to-year variability in emissions and air quality, and continued maintenance of the air quality standard over time. Both components of maintenance are addressed in this proposal.

Step One: Air Quality Analysis

In step one of this proposed approach, EPA analyzes emissions from 37 states to quantify the impact of those emissions on downwind nonattainment and maintenance sites in 2012 (*see* section IV.C for a detailed discussion of air quality modeling). To begin this analysis, EPA first identifies all monitors projected to be in nonattainment or, based on historic variability in air quality, projected to have maintenance problems in 2012. This baseline analysis takes into account emissions reductions associated with the implementation of all federal rules promulgated by December 2008 and assumes that the CAIR is not in effect. This baseline presents a unique situation. EPA has been directed to replace the CAIR; yet the CAIR remains in place and has led to significant emissions reductions in many states.

A key step in the process of developing a 110(a)(2)(D)(i)(I) rule involves analyzing existing (base case) emissions to determine which states significantly contribute to downwind nonattainment and maintenance areas. EPA cannot prejudge at this stage which states will be affected by the rule. For example, a state affected by CAIR may not be affected by the new rule and after the new rule goes into effect, the CAIR requirements will no longer apply. For a state covered by CAIR but not covered by the new rule, the CAIR requirements would not be replaced with new requirements, and therefore an increase in emissions relative to present levels could occur in that state. More fundamentally, the court has made clear that, due to legal flaws, the CAIR rule cannot remain in place and must be replaced. If EPA's base case analysis

were to ignore this fact and assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. For these reasons, EPA cannot assume in its base case analysis, that the reductions required by CAIR will continue to be achieved.

Following this logic, the 2012 base case shows emissions higher than current levels in some states. Because EPA has been directed to replace CAIR, EPA believes that for many states, the absence of the CAIR NO_X program will lead to the status quo of the NO_X Budget Program, which limits ozone-season NO_X emissions and ensures the operation of NO_X controls in those states. Also, without the CAIR SO_2 program, emission requirements in many areas would revert to the comparatively less stringent requirements of the Title IV Acid Rain Program. As a result, SO_2 emissions in many states would increase markedly in the 2012 base case relative to the present. Efforts to comply with ARP rules at the least-cost would occur in many cases without the operation of existing scrubbers through use of readily available, inexpensive Title IV allowances. Notably, all known controls that are required under state laws, NSPS, consent decrees, and other enforceable binding commitments through 2014 are accounted for in the base case. It is against this backdrop that the Transport Rule is analyzed and that significant contribution to nonattainment and interference with maintenance must be addressed.

Step Two: Quantifying Each State's Significant Contribution

In step two, EPA identifies the portion of each state's contributing emissions that constitute the emissions from that state that "significantly contribute to, or interfere with maintenance by" another state. To do so with respect to the 1997 ozone NAAQS, EPA analyzes the costs and associated air quality impacts of reductions in ozone-season NO_X. To do so with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS, EPA analyzes the costs and associated air quality impacts of reductions in annual SO_2 and annual NO_X. The analysis uses cost thresholds, informed by air quality considerations and applied on a state specific basis. EPA considered a number of factors, including air quality and cost factors because the circumstances that lead to nonattainment and maintenance problems at downwind sites are extremely complex. By using both cost and air quality factors, EPA's analysis can address the different circumstances influencing the linkages between upwind and downwind states. As such, EPA believes it is appropriate to consider these factors in identifying the emissions that must be prohibited.

While we believe it is important to consider cost, we also recognize that we can't "just pick a cost for the region and deem 'significant' any emissions that sources can eliminate more cheaply." *North Carolina,* 531 F.3d at 918. In contrast to the approach used in CAIR and the NO_X SIP Call, the cost thresholds EPA uses in this proposed approach are informed by air quality considerations and applied on a state specific basis. EPA first develops state-specific costs curves showing what level of emissions reductions could be achieved at different cost levels in 2012 and 2014. EPA then uses a simplified air quality assessment tool to examine the impact of the reductions at specific cost levels on downwind nonattainment and maintenance sites. This approach allows EPA to identify specific cost breakpoints based on air quality considerations (such as the cost at which the air quality assessment analysis projects large numbers of downwind sites maintenance and nonattainment problems would be resolved) or cost criteria (such as being a cost where large emissions reductions occur because a particular technology is widely implemented at that cost). EPA then evaluated the reasonableness of the cost breakpoints using a number of criteria to determine which of the breakpoints appropriately represented a cost threshold with which to define significant contribution.

These thresholds are then applied on a state-specific basis to quantify each individual state's significant contribution.

The remainder of this section provides further detail on the specific methodology developed by EPA and the application of this methodology to identify emissions that significantly contribute to or interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 $PM_{2.5}$ NAAQS.

B. Overview of Approach To Identify Contributing Upwind States

This section describes EPA's proposal to require reductions in upwind emissions of SO_2 and NO_X to address $PM_{2.5}$ transport and to require reductions in upwind emissions of NO_X to address ozone-related transport. In addition, this section provides an overview of EPA's approach to identifying which states are subject to the proposed rule, and which states are not subject to the rule because their sources' emissions were found to not significantly contribute to nonattainment of the $PM_{2.5}$ or 8-hour ozone standards or interfere with maintenance of those standards, in downwind states.

The EPA assessed individual upwind states" 2012 projected ambient impacts on downwind nonattainment and maintenance receptors for a 37-state region in the eastern U.S., and established threshold values for $PM_{2.5}$ and ozone to identify those states whose impact does not constitute a significant contribution to air quality violations in the downwind states. EPA used these same threshold values in considering the potential for upwind state emissions to interfere with maintenance of the $PM_{2.5}$ and 8-hour ozone NAAQS in downwind areas. The EPA used air quality modeling of emissions in each state to estimate the ambient impacts. The air quality modeling platform and approach to quantifying interstate contributions to $PM_{2.5}$ and ozone are discussed in section IV.C.

As noted previously, EPA considers that the maintenance concept has two components: Year-to-year variability in emissions and air quality, and continued maintenance of the air quality standard over time. The way that EPA defined maintenance based on year-to-year variability is discussed in section IV.C., and directly affects the proposed requirements of this rule. EPA also considered whether further reductions were necessary to ensure continued lack of interference with maintenance of the NAAQS over time. EPA concluded that in light of projected emission trends, and also considering the emissions reductions from this proposed rule, no further reductions are required solely for this purpose at PM and ozone receptors for which we are partially or fully determining significant contribution for the current NAAQS. (*See* discussion of emissions trends in Chapter 7 of TSD entitled "Emission Inventories," included in the docket for this proposal.)

1. Background

a. For the CAIR, how did EPA determine which pollutants were necessary to control to address interstate transport for $PM_{2.5}$?

Section II of the January 2004 CAIR proposal summarized key scientific and technical aspects of the occurrence, formation, and origins of $PM_{2.5}$, as well as findings and observations relevant to formulating control approaches for reducing the contribution of transport to

fine particle problems (69 FR 4575–87). Key concepts and provisional conclusions drawn from this discussion were summarized as follows in the preamble to the final CAIR:

(1) Fine particles (measured as $PM_{2.5}$ for the NAAQS) consist of a diverse mixture of substances that vary in size, chemical composition, and source. The $PM_{2.5}$ includes both "primary" particles that are emitted directly to the atmosphere as particles, and "secondary" particles that form in the atmosphere through chemical reactions from gaseous precursors. The major components of fine particles in the eastern U.S. can be grouped as follows: Carbonaceous material (including both primary and secondary organic carbon and black carbon); sulfates; nitrates; ammonium; and crustal material, which includes suspended dust as well as some other directly emitted materials. The major gaseous precursors of $PM_{2.5}$ include SO_2, NO_X, NH_3, and certain volatile organic compounds.

(2) Examination of urban and rural monitors indicate that in the eastern U.S., sulfates, carbonaceous material, nitrates, and ammonium associated with sulfates and nitrates are typically the largest components of transported $PM_{2.5}$, while crustal material tends to be only a small fraction.

(3) Atmospheric interactions among particulate ammonium sulfates and nitrates and gas phase nitric acid and ammonia vary with temperature, humidity, and location. Both ambient observations and modeling simulations suggest that regional SO_2 reductions are effective at reducing sulfate and associated ammonium, and, therefore, $PM_{2.5}$. Under certain conditions reductions in particulate ammonium sulfates can release ammonia as a gas, which then reacts with gaseous nitric acid to form nitrate particles, a phenomenon called "nitrate replacement." In such conditions SO_2 reductions would be less effective in reducing $PM_{2.5}$, unless accompanied by reductions in NO_X emissions to address the potential increase in nitrates.

(4) Reductions in ammonia can reduce the ammonium, but not the sulfate portion of sulfate particles. The relative efficacy of reducing nitrates through NO_X or ammonia control varies with atmospheric conditions; the highest particulate nitrate concentrations in the East tend to occur in cooler months and regions. At present, our knowledge about sources, emissions, control approaches, and costs is greater for NO_X than for ammonia. Measures to reduce NO_X from stationary and mobile sources have been implemented for more than 20 years. From a chemical perspective, as NO_X reductions accumulate relative to ammonia, the atmospheric chemical system would move towards an equilibrium in which ammonium nitrate reductions become more responsive to further NO_X reductions relative to ammonia reductions.

(5) Much less is known about the sources of regional transport of carbonaceous material. Key uncertainties include how much of this material is due to biogenic as compared to anthropogenic sources, and how much is directly emitted as compared to formed in the atmosphere.

Based on the understanding of current scientific and technical information, as well as EPA's air quality modeling, as summarized in the CAIR proposal, EPA concluded that it was both appropriate and necessary to focus on control of SO_2 and NO_X emissions as the most effective approach to reducing the contribution of interstate transport to $PM_{2.5}$.

For the CAIR, the EPA did not include emissions controls that affect other components of $PM_{2.5}$, noting that "current information relating to sources and controls for other components identified in transported $PM_{2.5}$ (carbonaceous particles, ammonium, and crustal materials) does not, at this time, provide an adequate basis for regulating the regional transport of emissions responsible for these $PM_{2.5}$ components." (69 FR 4582). For all of these components, the lack of knowledge of and ability to quantify accurately the interstate transport of these components limited EPA's ability to include these components in the CAIR.

b. For the CAIR, how did EPA determine which pollutants were necessary to control to address interstate transport for ozone?

In the notice of proposed rulemaking for the CAIR, EPA provided the following characterization of the origin and distribution of 8-hour ozone air quality problems:

The ozone present at ground level as a principal component of photochemical smog is formed in sunlit conditions through atmospheric reactions of two main classes of precursor compound: VOCs and NO_X (mainly NO and NO_2). The term "VOC" includes many classes of compounds that possess a wide range of chemical properties and atmospheric lifetimes, which help determine their relative importance in forming ozone. Sources of VOCs include man-made sources such as motor vehicles, chemical plants, refineries, and many consumer products, but also natural emissions from vegetation. Nitrogen oxides contributing to ozone formation are emitted by motor vehicles, power plants, and other combustion sources, with lesser amounts from natural processes including lightning and soils. Key aspects of current and projected inventories for NO_X and VOC are summarized in section IV of the proposal notice and EPA Web sites (*e.g., http://www.gov/ttn/chief.*) The relative importance of NO_X and VOC in ozone formation and control varies with local- and time-specific factors, including the relative amounts of VOC and NO_X present. In rural areas with high concentrations of VOC from biogenic sources, ozone formation and control is governed by NO_X. In some urban core situations, NO_X concentrations can be high enough relative to VOC to suppress ozone formation locally, but still contribute to increased ozone downwind from the city. In such situations, VOC reductions are most effective at reducing ozone within the urban environment and immediately downwind. The formation of ozone increases with temperature and sunlight, which is one reason ozone levels are higher during the summer. Increased temperature also increases emissions of volatile man-made and biogenic organics and can indirectly increase NO_X as well (*e.g.*, increased electricity generation for air conditioning). Summertime conditions also bring increased episodes of large-scale stagnation, which promote the build-up of direct emissions and pollutants formed through atmospheric reactions over large regions. Authoritative assessments of ozone control approaches have concluded that, for reducing regional scale ozone transport, a NO_X control strategy would be most effective, whereas VOC reductions are most effective in more dense urbanized areas.

Studies conducted in the 1970s established that ozone occurs on a regional scale (*i.e.*, 1,000s of kilometers) over much of the eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas. While substantial progress has been made in reducing ozone in many urban areas, regional scale ozone transport is still an important component of high ozone concentrations during the extended summer ozone season. A series of more recent progress reports discussing the effect of the NO_X SIP Call reductions can be found on EPA's Web site at: *http://www.epa.gov/airmarkets/progress/progress-reports.html.*

In the notice of proposed rulemaking for CAIR, EPA noted that we continue to rely on the assessment of ozone

transport made in great depth by the OTAG in the mid-1990s. As indicated in the NO_X SIP Call proposal, the OTAG Regional and Urban Scale Modeling and Air Quality Analysis Work Groups concluded that regional NO_X emissions reductions are effective in producing ozone benefits; the more NO_X reduced, the greater the benefit.

More recent assessments of ozone, for example those conducted for the Regulatory Impact Analysis for the ozone standards in 2008, continue to show the importance of NO_X transport. Information on these analyses can be found at EPA's Web site at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/452_R_08_003.pdf*.

For addressing interstate ozone transport in the CAIR, EPA addressed NO_X emissions, but did not include requirements for VOCs. EPA believes that VOCs from some upwind states do indeed have an impact in some nearby downwind states, particularly over short transport distances. The EPA expects that states will need to examine the extent to which VOC emissions affect ozone pollution levels across state lines, and identify areas where multi-state VOC strategies might assist in meeting the 8-hour standard, in planning for attainment.

c. For the CAIR, which thresholds were used to identify states included under the rule?

(1) Fine Particles

In the CAIR, EPA used as the metric for identifying a state as significantly contributing (depending upon further consideration of costs) to downwind nonattainment, the predicted change, due to the upwind state's NO_X and SO_2 emissions, in annual[19] $PM_{2.5}$ concentration in the downwind nonattainment area that receives the largest ambient impact. The EPA proposed this metric in the form of a range of alternatives for a "bright line," that is, air quality impacts at or greater than the chosen threshold level indicated that the upwind state's emissions do contribute significantly (depending on cost considerations), and that air quality impacts below the threshold indicate that the upwind state's emissions do not contribute significantly to nonattainment.

This metric addresses how much each state contributes to a downwind neighbor. EPA does not believe that a particular upwind state must contribute to multiple downwind receptors to be required to make emissions reductions under CAA section 110(a)(2)(D). Under this provision, an upwind state must include in the SIP adequate provisions that prohibit that state's emissions that "contribute significantly to nonattainment in * * * any other State * * *" 42 U.S.C. 7410(a)(2)(D)(i)(I). Our interpretation of this provision is that the emphasized terms make clear that the upwind state's emissions must be controlled as long as they contribute significantly to a single nonattainment area.

As discussed in section II of the preamble to the final CAIR, EPA's approach to evaluating a state's impact on downwind nonattainment considered the entirety of the state's SO_2 and NO_X emissions, rather than treating them separately. We believed this approach was consistent with the chemical interactions in the atmosphere of SO_2 and NO_X in forming $PM_{2.5}$. The contributions of SO_2 and NO_X emissions are generally not additive, but rather are interrelated due to complex chemical reactions.

In the CAIR proposal, EPA proposed to establish a state-level annual average $PM_{2.5}$ contribution threshold from anthropogenic SO_2 and NO_X emissions that was a small percentage of the annual air quality standard of 15.0 μg/m³. The EPA based this proposal on the general concept that an upwind state's contribution of a relatively low level of ambient impact should be regarded as significant (depending on the further assessment of the control costs). We based our reasoning on several factors. The EPA's modeling indicates that at least some nonattainment areas will find it difficult to attain the standards without reductions in upwind emissions. In addition, our analysis of base case $PM_{2.5}$ transport shows that, in general, $PM_{2.5}$ nonattainment problems result from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and, in some cases, substantially larger contributions from a subset of particular upwind states. In the NO_X SIP Call rulemaking, we termed this pattern of contribution—which is also present for ozone nonattainment—"collective contribution."

In the case of $PM_{2.5}$, we have found collective contribution to be a pronounced feature of the $PM_{2.5}$ transport problem, in part because the annual nature of the $PM_{2.5}$ NAAQS means that throughout the entire year and across a range of wind patterns—rather than during just one season of the year or on only the few worst days during the year which may share a prevailing wind direction—emissions from many upwind states affect the downwind nonattainment area.

As a result, to address the transport affecting a given nonattainment or maintenance area, many upwind states must reduce their emissions, even though their individual contributions may be relatively small. As a result, for the CAIR EPA determined that a relatively low value for the $PM_{2.5}$ transport contribution threshold was appropriate. For the final CAIR EPA decided to apply a threshold of 0.20 μg/m³, such that any model result that is below this value (0.19 or less) indicates a lack of significant contribution, while values of 0.20 or higher exceeded the threshold.

(2) Ozone

For the CAIR ozone program, in assessing the contribution of upwind states to downwind 8-hour ozone nonattainment, EPA followed the approach used in the NO_X SIP Call and employed the same contribution metrics, but with an updated model and updated inputs.

The air quality modeling approach we proposed to quantify the impact of upwind emissions included two different methodologies: Zero-out and source apportionment. EPA applied each methodology to estimate the impact of all of the upwind state's anthropogenic NO_X and VOC emissions on each downwind nonattainment area.

The EPA's first step in evaluating the results of these methodologies was to remove from consideration those states whose upwind contributions were very low. Specifically, EPA considered an upwind state not to contribute significantly to a downwind nonattainment area if the state's maximum contribution to the area was either (1) less than 2 ppb; or (2) less than one percent of total nonattainment in the downwind area; as indicated by either of the two modeling techniques.

If the upwind state's impact exceeded these thresholds, then EPA conducted a further evaluation to determine if the impact was high enough to meet the air quality portion of the "contribute significantly" standard. In doing so, EPA organized the outputs of the two modeling techniques into a set of "metrics." The metrics reflect three key contribution factors:

- The magnitude of the contribution (actual amount of ozone contributed by emissions in the upwind state to nonattainment in the downwind area);
- The frequency of the contribution (how often contributions above certain thresholds occur); and
- The relative amount of the contribution (the total ozone

[19] For the CAIR, 24-hour $PM_{2.5}$ was not at issue because there were little or no exceedances of the then-existing 65 μg/m³ 24-hour standards

contributed by the upwind state compared to the total amount of nonattainment ozone in the downwind area).

2. Approach for Proposed Rule

a. Which pollutants do we propose to control?

For the proposed rule, EPA believes that the conclusions and findings in the final CAIR regarding the nature of pollutant contributions are still appropriate. EPA proposes to continue to focus the $PM_{2.5}$ transport requirements on SO_2 and NO_X transport, and the ozone transport requirements on NO_X.

EPA recognizes that, in some circumstances, the state's NO_X contribution to $PM_{2.5}$ in downwind states may be considerably smaller than the state's SO_2 contribution to $PM_{2.5}$ in downwind states. In addition, for monitors in EPA's speciation trends network that are located in southern states with warmer climates, the level of monitored nitrates can be very small. For these states, it is possible that annual NO_X controls, within levels that could realistically be achieved, would result in a very small change in ambient $PM_{2.5}$ levels. EPA considered identifying states where this was the case. For a number of reasons, we propose not to take this course of action. First, these states can impact downwind states in cooler climates, and thus impact nitrate formation in those downwind states. For example, EPA modeling results show that Georgia's emissions are linked to Ohio, Maryland, New Jersey, and Pennsylvania where monitored nitrates are higher. Second, EPA is concerned with the possibility for the "nitrate replacement" effect described previously. That is, there is a possibility for increases in nitrate particles if SO_2 emissions decrease without accompanying decreases in NO_X. Third, EPA believes that there would be important disbenefits to relaxing annual NO_X requirements in those states. If for those states, EPA were to relax the annual NO_X requirements currently required for their contribution to $PM_{2.5}$, annual NO_X emissions would increase, with potentially harmful effects on visibility and nitrogen deposition.

b. Thresholds

For the proposed rule, as for CAIR, EPA uses air quality thresholds to identify states whose contributions do not warrant transport requirements. We propose air quality thresholds for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone. Each threshold is based on 1 percent of the NAAQS.

As we found at the time of the CAIR, EPA's analysis of base case $PM_{2.5}$ transport shows that, in general, $PM_{2.5}$ nonattainment problems result from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and, in some cases, substantially larger contributions from a subset of particular upwind states. For ozone, as we found in the CAIR and the SIP call, we also found important contributions from multiple upwind states. In short, EPA continues to find an upwind "collective contribution" that is important to both $PM_{2.5}$ and ozone.

A second reason that low threshold values are warranted, as EPA discussed in the notices for the CAIR, is that there are adverse health impacts associated with ambient $PM_{2.5}$ and ozone even at low levels. See relevant portions of the CAIR proposal notice (63 FR 4583–84) and the CAIR final rule notice (70 FR 25189–25192).

For annual $PM_{2.5}$ for the final CAIR, as noted previously, EPA decided to use a single-digit value, 0.2 $\mu g/m^3$, rather than the two-digit value in the proposed CAIR, 0.15 $\mu g/m^3$. The rationale for the single digit value for the final rule was that a single digit is consistent with the EPA monitoring requirements in part 50, appendix N, section 4.3. The reporting requirements for annual $PM_{2.5}$ require that:

> Annual $PM_{2.5}$ standard design values shall be rounded to the nearest 0.1 $\mu g/m^3$ (decimals 0.05 and greater are rounded up to the next 0.1, and any decimal lower than 0.05 is rounded down to the nearest 0.1).

Because the design value is to be reported only to the nearest 0.1 $\mu g/m^3$, EPA deemed it preferable for the final CAIR to select the threshold value at the nearest 0.1 $\mu g/m^3$ as well, and hence one percent of the 15 $\mu g/m^3$, rounded to the nearest 0.1 $\mu g/m^3$ became 0.2 $\mu g/m^3$.

For the 24-hour standard of 35 $\mu g/m^3$, we attempted to apply the same rationale for determining a single-digit air quality threshold. That is, we applied rounding conventions in Part 50, Appendix N to a value representing one percent of the NAAQS. The rounding requirements for the 24-hour standard are indicated in section 4.3 as follows:

> 24-hour $PM_{2.5}$ standard design values shall be rounded to the nearest 1 $\mu g/m^3$ (decimals 0.5 and greater are rounded up to the nearest whole number, and any decimal lower than 0.5 is rounded down to the nearest whole number).

One percent of the 24-hour standard is 0.35 $\mu g/m^3$, and rounding to the nearest whole $\mu g/m^3$ would yield an air quality threshold of zero. Thus applying the same rationale for the final CAIR, there would be no air quality threshold for 24-hour $PM_{2.5}$, which EPA believes to be counterintuitive and unworkable as an approach for assessing interstate contributions.

For the proposed rule, EPA proposes to decouple the precision of the air quality thresholds with the monitoring reporting requirements, and to use 2-digit values representing one percent of the NAAQS, that is, 0.15 $\mu g/m^3$ for the annual standard, and 0.35 $\mu g/m^3$ for the 24-hour standard. EPA believes there are a number of considerations favoring this approach. First, it provides for a consistent approach for the annual and 24-hour standards. Second, the approach is readily applicable to any current and future NAAQS. For example, if EPA were to retain the CAIR approach for the annual standard, any future lowering of the $PM_{2.5}$ NAAQS to below 15 $\mu g/m^3$ would reduce the air quality threshold to 0.1 $\mu g/m^3$. This would occur because any value less than 0.15 $\mu g/m^3$ (*e.g.*, 0.14 $\mu g/m^3$) would be rounded down to 0.1 $\mu g/m^3$. EPA finds it within its discretion to adjust its approach to account for the additional considerations that were not in existence at the time of the final CAIR.

For the proposal, EPA is proposing to take a more straightforward approach to air quality thresholds for ozone than the multi-factor approach we used for the NO_X SIP Call or for the CAIR. The proposed approach uses a single "bright line" threshold for ozone that is one percent of the 1997 8-hour ozone standard of 0.08 ppm. As described later in section IV.C, the 1 percent threshold is averaged over multiple model days. EPA believes this to be a robust metric compared to previous metrics which might have relied on the maximum contribution on a single day. Under this approach, one percent of the NAAQS is a value of 0.8 ppb. State contributions of 0.8 ppb and higher are above the threshold; ozone contributions less than 0.8 ppb are below the threshold. EPA believes that this approach is preferable because it is a robust metric, it is consistent with the approach for $PM_{2.5}$, and because it provides for a consistent approach that takes into account, and is applicable to, any future ozone standards below 0.08 ppm.

EPA seeks comment on the pollutants and air quality thresholds used for identifying states to be included under the proposed rule. In particular, EPA requests comment on alternatives to the 1 percent threshold. In addition, EPA requests comment on whether EPA should use the same rounding

convention that was used in the final CAIR for the 15 μg/m^3 annual $PM_{2.5}$ standard, or whether commenters agree with EPA's approach that does not use this rounding convention. To identify the potential effect of alternative thresholds for the annual $PM_{2.5}$ standard, *see* Table IV.C–13 (showing state specific contributions to areas with annual $PM_{2.5}$ nonattainment and maintenance issues) and Table IV.C–16 (showing state specific contributions to areas with 24-hour $PM_{2.5}$ nonattainment and maintenance issues).

C. Air Quality Modeling Approach and Results

1. What air quality modeling platform did EPA use?

a. Introduction

In this section, we describe the air quality modeling performed to support the proposed rule. We used air quality modeling to (1) identify locations where we expect there to be nonattainment or maintenance problems for annual average $PM_{2.5}$, 24-hour $PM_{2.5}$, and/or 8-hour ozone for the analytic years chosen for this proposal, (2) quantify the impacts (*i.e.*, air quality contributions) of SO_2 and NO_X emissions from upwind states on downwind annual average and 24-hour $PM_{2.5}$ concentrations at monitoring sites projected to be nonattainment or have maintenance problems in 2012 for the 1997 annual and 2006 24-hour $PM_{2.5}$ NAAQS, respectively, (3) quantify the impacts of NO_X emissions from upwind states on downwind 8-hour ozone concentrations at monitoring sites projected to be nonattainment or have maintenance problems in 2012 for the 1997 ozone NAAQS, and (4) assess the health and welfare benefits of the emissions reductions expected to result from this proposal. This section includes information on the air quality model applied in support of the proposed rule, the meteorological and emissions inputs to these models, the evaluation of the air quality model compared to measured concentrations, and the procedures for projecting ozone and $PM_{2.5}$ concentrations for future year scenarios. We also provide in this section the interstate contributions for annual average and 24-hour $PM_{2.5}$, and 8-hour ozone. The Air Quality Modeling Technical Support Document (AQMTSD) contains more detailed information on the air quality modeling aspects of this rule.

To support the proposal, air quality modeling was performed for four emissions scenarios: A 2005 base year, a 2012 "no CAIR" base case, a 2014 "no CAIR" base case, and a 2014 control case that reflects the emissions reductions expected from the proposed FIPs. The remedy proposed for inclusion in the FIPs is described in section V.D. The modeling for 2005 was used as the base year for projecting air quality for each of the 3 future year scenarios. The 2012 base case modeling was used to identify future nonattainment and maintenance locations and to quantify the contributions of emissions in upwind states to annual average and 24-hour $PM_{2.5}$ and 8-hour ozone. The 2014 base case and 2014 control case modeling were used to quantify the benefits of this proposal.

For CAIR, EPA used the Comprehensive Air Quality Model with Extensions (CAMx) version 5 [20] to simulate ozone and $PM_{2.5}$ concentrations for the 2005 base year and the 2012 and 2014 future year scenarios. In contrast, for the CAIR EPA used two air quality models, CAMx version 3.1 for modeling ozone and the Community Multiscale Air Quality Model (CMAQ) version 4.3 for modeling $PM_{2.5}$. Both CAMx and CMAQ are grid cell-based, multi-pollutant photochemical models that simulate the formation and fate of ozone and fine particles in the atmosphere. The use of one model for both pollutants, as we have done for this proposal, provides a more scientifically integrated "one atmosphere" approach versus using different models for ozone and $PM_{2.5}$. In addition, using a single model rather than two models is computationally more efficient. The CAMx model applications were designed to cover states in the central and eastern U.S. using a horizontal resolution of 12 x 12 km.[21] The modeling region (*i.e.*, modeling domain) extends from Texas northward to North Dakota and eastward to the East Coast and includes 37 states and the District of Columbia. A map of the air quality modeling domain is provided in the AQMTSD.

Both CAMx and CMAQ contain certain source apportionment tools that are designed to quantify the contribution of emissions from various sources and areas to ozone and $PM_{2.5}$ component species in other downwind locations. The CAMx model was chosen for use in this proposal because the source apportionment tools in this model have had extensive use and evaluation by states and industry. Also, the source apportionment tools in CAMx received favorable comments in a recent peer review.[22]

The 2005-based air quality modeling platform used for the proposal includes 2005 base year emissions and 2005 meteorology for modeling ozone and $PM_{2.5}$ with CAMx. This platform provides an update to the now more historical data in the 2001-based platform used for CAIR that included 2001 emissions, 2001 meteorology for modeling $PM_{2.5}$, and 1995 meteorology for modeling ozone. In the remainder of this section we provide an overview of (1) the emissions and meteorological components of the 2005-based platform, (2) the methods for projecting future nonattainment and maintenance along with a list of 2012 base case nonattainment and maintenance locations, (3) the approach to developing metrics to measure interstate contributions to annual and 24-hour $PM_{2.5}$ and ozone, and (4) the predicted interstate contributions to downwind nonattainment and maintenance. We also identify which predicted interstate contributions are at or above the air quality impact thresholds described previously in section IV.B.

b. Emissions Inventories

Emissions estimates were made for a 2005 base year and for 2012 and 2014. All inventories include emissions from EGUs, nonEGU point sources, stationary nonpoint sources, onroad mobile sources, and nonroad mobile sources. When emissions were only available at annual or monthly temporal resolutions, emissions modeling steps were applied to estimate hourly emissions. Point source emissions were assigned to modeling grid cells based on latitude and longitude in the inventory, and county total emissions were allocated to grid cells. Emissions of NO_X, VOCs and $PM_{2.5}$ were split into their component species using other data sources, to provide the modeling species needed by CAMx. Elevated point sources were identified for simulating releases of emissions from those sources in layers 2 and higher in CAMx. In addition to the anthropogenic emission sources described previously, hourly, gridded biogenic emissions were estimated for individual modeling days using the BEIS model version 3.14.[23] [24] The same

[20] Comprehensive Air Quality Model with Extensions Version 5 User's Guide. Environ International Corporation. Novato, CA. March 2009.

[21] The 12 km domain was nested within a coarse grid, 36 x 36 km modeling domain which covers the lower 48 states and adjacent portions of Canada and Mexico. Predictions from this Continental U.S. (CONUS) domain were used to provide initial and boundary concentrations for simulations in the 12 km domain.

[22] Arunachalam, S. Peer Review of Source Apportionment Tools in CAMx and CMAQ, EP–D–07–102. University of North Carolina, Institute for the Environment, August 2009.

[23] Pouliot, G., Pierce., T. "A Tale of Two Models: A comparison of the Biogenic Emission Inventory System (BEIS) and Model of Emissions of Gases and

biogenic emissions data were used in all scenarios modeled.

(1) Development of 2005 Base Year Emissions

Emissions inventory inputs representing the year 2005 were developed to provide a base year for forecasting future air quality, described in section IV.C.2. The 2005 National Emission Inventory (NEI), version 2 from October 6, 2008, was the starting point for the U.S. inventories used for the 2005 air quality modeling. This inventory includes 2005-specific data for point and mobile sources, while most nonpoint data were carried forward from version 3 of the 2002 NEI. In addition, a 2006 Canadian inventory and a 1999 Mexican inventory were used for the portions of Canada and Mexico within the modeling domains. Additional details on these inventories and the augmentation described here are available from the Emissions Inventory Technical Support Document (EITSD) for the Transport Rule.

The onroad and nonroad emissions were primarily based on the National Mobile Inventory Model (NMIM) monthly, county, process level emissions from the 2005 NEI v2. The 2005 onroad mobile emissions were augmented for onroad gasoline emissions sources with emissions based on a draft version of the Motor Vehicle Emissions Simulator (MOVES) for carbon monoxide (CO), NO_X, VOC, $PM_{2.5}$, and particulate matter less than ten microns (PM_{10}). While these data were preliminary, they more closely reflect the $PM_{2.5}$ emissions from the final release of MOVES 2010. To account for the temperature dependence of $PM_{2.5}$, MOVES-based temperature adjustment factors were applied to gridded, hourly emissions using gridded, hourly meteorology. Additional information on this approach is available in the EITSD.

The annual NO_X and SO_2 emissions for EGUs in the 2005 NEI v2 are based primarily on data from EPA's Clean Air Markets Division's Continuous Emissions Monitoring (CEM) program, with other pollutants estimated using emission factors and the CEM annual heat input. For EGUs without CEMs, data were obtained from the states as included in the NEI. For modeling, the 2005 EGU emissions for SO_2 and NO_X were augmented by using hourly CEM data to develop a temporal allocation approach of the 2005 NEI v2 emissions. The annual emissions themselves were unchanged, and match closely with data from the CEM program except where states have provided data for partial CEM and non-CEM units. The 2005 EGUs were identified as all units in 2005 that map to the units modeled by the version of the Integrated Planning Model (IPM) used for this proposal, and include records both with and without data submitted to the CEM program. Temporal profiles were used instead of the actual 2005 CEM data so that the temporal allocation approach could be consistent in the future year modeling.

For the 2005 base year, the annual EGU NEI emissions were allocated to hourly emissions values needed for modeling based on the 2004, 2005, and 2006 CEM data. The NO_X CEM data were used to create NO_X-specific profiles, the SO_2 data were used to create SO_2-specific profiles, and the heat input data were used to allocate all other pollutants. The 3 years of data were used to create state-specific profiles to allocate from annual to monthly values and from daily to hourly values. Only the 2005 data were used to create state-specific factors for allocation from month to day, which is intended to preserve an appropriate level of daily temporal variability needed for this type of modeling.

Other significant augmentations were also made to the 2005 NEI and include the following. The nonpoint inventory was augmented with the oil and gas exploration inventory [25] which includes emissions in several states within the eastern U.S. 12 km modeling domain and additional states within the national 36 km modeling domain. The commercial marine category 3 (C3) vessel emissions were augmented with gridded 2005 emissions from the previous modeling efforts for the rule called "Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder." The 2005 point source daily wildfire and prescribed burning emissions were replaced with average-year county-based inventories. Additionally, the inventories were processed to provide the hourly, gridded, model-species needed by CAMx.

Tables IV.C–1 and IV.C–2 provide summaries of SO_2 and NO_X emissions by state by sector for the 2005 base year for those states within the eastern 12 km modeling domain. Emissions for other states within the 36 km modeling domain are available in the EISTD. In the tables, the EGU column summarizes all units matched to the IPM model and the nonEGU column is for other point source units. The Nonpoint column shows emissions for all nonpoint stationary sources. The Nonroad column summarizes emissions for nonroad mobile sources, including aircraft, locomotive, and marine sources including the C3 commercial marine. The Onroad column summarizes emissions for the combined NEI and draft MOVES-based emissions, in which emissions from the draft MOVES were used when available, and NEI emissions based on MOBILE6 were used for the remainder. Finally, the Fires column represents the average-year fire emissions for wildfires and prescribed burning mentioned previously.

TABLE IV.C–1—2005 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	460,123	70,346	52,325	6,397	3,199	983	593,372
Arkansas	66,384	13,066	27,260	5,678	1,632	728	114,749
Connecticut	10,356	1,831	18,455	2,548	1,128	4	34,320
Delaware	32,378	34,859	5,859	11,648	422	6	85,173
District of Columbia	1,082	686	1,559	414	172	0	3,914
Florida	417,321	57,475	70,490	93,543	10,285	7,018	656,131
Georgia	616,054	56,116	56,829	13,331	5,690	2,010	750,031
Illinois	330,382	156,154	5,395	19,302	5,716	20	516,969
Indiana	878,978	95,200	59,775	9,436	3,981	24	1,047,396
Iowa	130,264	61,241	19,832	8,838	1,702	25	221,902
Kansas	136,520	13,142	36,381	8,035	1,824	103	196,005

Aerosols from Nature (MEGAN)," 7th Annual Community Multiscale Analysis System Conference, Chapel Hill, NC, October 6–8, 2008.

[24] Donna Schwede, D., Pouliot, G., and Pierce, T. "Changes to the Biogenic Emissions Inventory System Version 3 (BEIS3)," 4th Annual Community Multiscale Analysis System Conference, Chapel Hill, NC, September 26–28, 2005.

[25] The oil and gas exploration inventory was provided by the Western Regional Air Partnership.

TABLE IV.C–1—2005 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Kentucky	502,731	25,811	34,229	6,942	2,711	364	572,787
Louisiana	109,851	165,737	2,378	73,233	2,399	892	354,489
Maine	3,887	18,519	9,969	3,725	834	150	37,084
Maryland	283,205	34,988	40,864	17,819	2,966	32	379,874
Massachusetts	85,768	19,620	25,261	25,335	2,168	93	158,245
Michigan	349,877	76,510	42,066	14,533	7,204	91	490,280
Minnesota	101,666	25,169	14,747	10,410	2,558	631	155,181
Mississippi	74,117	29,892	6,796	6,003	2,158	1,051	120,016
Missouri	284,384	78,307	44,573	10,464	4,251	186	422,165
Nebraska	74,955	6,429	29,575	9,199	1,326	105	121,589
New Hampshire	51,445	3,245	7,408	805	630	38	63,571
New Jersey	57,044	7,640	10,726	23,484	2,486	61	101,441
New York	180,847	58,562	125,158	20,908	5,628	113	391,216
North Carolina	512,231	66,150	22,020	42,743	5,341	696	649,181
North Dakota	137,371	9,458	6,455	5,986	443	66	159,779
Ohio	1,116,084	118,468	19,810	15,615	6,293	22	1,276,292
Oklahoma	110,081	40,482	7,542	5,015	2,699	469	166,288
Pennsylvania	1,002,202	85,411	68,349	11,972	5,363	32	1,173,328
Rhode Island	176	2,743	3,365	2,494	208	1	8,987
South Carolina	218,782	31,495	30,016	20,477	2,976	646	304,393
South Dakota	12,215	1,698	10,347	3,412	511	498	28,682
Tennessee	266,148	78,206	32,714	6,288	4,834	277	388,468
Texas	534,949	223,625	109,215	52,749	13,470	1,178	935,187
Vermont	9	902	5,385	385	305	49	7,036
Virginia	220,248	69,440	32,923	18,420	3,829	399	345,259
West Virginia	469,456	48,314	14,589	2,133	1,095	215	535,802
Wisconsin	180,200	66,807	6,369	7,129	3,110	70	263,685
Grand total	10,019,774	1,953,745	1,117,009	596,847	123,547	19,345	13,380,267

TABLE IV.C–2—2005 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	133,051	74,830	32,024	61,623	142,221	3,814	447,562
Arkansas	35,407	37,478	21,453	63,493	81,014	2,654	241,499
Connecticut	6,865	5,824	12,554	21,785	69,645	14	116,688
Delaware	11,917	5,567	3,259	15,567	22,569	23	58,902
District of Columbia	492	501	1,740	3,494	9,677	0	15,904
Florida	217,263	53,778	29,533	277,888	460,474	25,600	1,064,537
Georgia	111,017	53,297	38,919	95,175	279,449	7,955	585,812
Illinois	127,923	97,504	47,645	223,697	276,507	71	773,347
Indiana	213,503	73,647	30,185	110,100	187,426	88	614,949
Iowa	72,806	39,299	15,150	92,965	91,795	90	312,105
Kansas	90,220	70,785	42,286	86,553	76,062	378	366,285
Kentucky	164,743	35,432	17,557	90,669	127,435	1,326	437,163
Louisiana	63,791	165,162	27,559	301,170	112,889	3,254	673,824
Maine	1,100	18,309	7,423	13,379	38,469	566	79,246
Maryland	62,574	24,621	21,715	55,812	129,796	137	294,656
Massachusetts	25,618	18,429	34,373	74,419	118,148	341	271,327
Michigan	120,005	94,139	43,499	101,087	279,816	330	638,876
Minnesota	83,836	64,438	56,700	115,873	146,138	2,300	469,286
Mississippi	45,166	53,985	12,212	79,394	98,060	3,833	292,649
Missouri	127,431	38,604	32,910	123,228	183,022	678	505,873
Nebraska	52,426	12,156	13,820	107,180	58,643	381	244,607
New Hampshire	8,827	3,241	11,235	9,246	32,537	137	65,223
New Jersey	30,114	20,598	26,393	88,486	157,736	223	323,550
New York	63,465	55,122	87,608	121,363	282,072	412	610,042
North Carolina	111,576	44,502	18,869	135,936	225,756	11,424	548,064
North Dakota	76,381	7,545	10,046	59,635	21,575	240	175,422
Ohio	258,687	71,715	41,466	173,988	270,383	81	816,321
Oklahoma	86,204	73,465	94,574	55,424	117,240	1,709	.....
Pennsylvania	176,870	89,208	53,435	118,774	266,649	117	705,053
Rhode Island	545	2,164	2,964	7,798	13,456	4	26,930
South Carolina	53,823	29,069	20,281	68,146	128,765	2,357	302,441
South Dakota	15,650	5,035	5,766	30,324	24,850	1,817	83,442
Tennessee	102,934	60,353	18,676	82,331	207,410	1,012	472,717
Texas	176,170	292,806	274,338	377,246	615,715	4,890	1,741,166
Vermont	297	799	3,438	3,951	13,316	179	21,980
Virginia	62,512	60,101	53,605	91,298	194,173	1,456	463,145
West Virginia	159,804	36,913	14,519	32,739	50,040	785	294,801

TABLE IV.C–2—2005 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Wisconsin	72,170	40,688	21,994	75,981	147,952	256	359,042
Grand total	3,223,184	1,931,111	1,301,726	3,647,215	5,758,880	80,931	15,943,047

(2) Development of Future Year Emissions

The future base case scenarios represent predicted emissions in the absence of any further controls beyond those federal measures already promulgated. For EGUs, all state and other programs available at the time of modeling have been included. For mobile sources, all national measures available at the time of modeling have been included. For nonEGU point and nonpoint stationary sources, any local control programs that may be necessary for areas to attain the annual $PM_{2.5}$ NAAQS and the ozone NAAQS are not included in the future base case projections. The future base case scenarios do reflect projected economic changes and fuel usage for EGU and mobile sectors, as described in the EITSD.

Tables IV.C–3 through IV.C–6 provide 2012 and 2014 summaries of emissions data for 2012 and 2014 modeling for all sectors for SO_2 and NO_X for states included in the 12 km modeling domain. The EITSD provides summaries for additional pollutants with additional detail and for all states in the nationwide 36 km modeling domain.

TABLE IV.C–3—2012 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	335,734	70,346	52,315	2,333	585	983	462,297
Arkansas	85,068	13,054	27,257	818	336	728	127,259
Connecticut	5,493	1,831	18,443	1,292	330	4	27,392
Delaware	7,841	10,974	5,858	14,193	98	6	38,970
District of Columbia	0	686	1,559	10	41	0	2,296
Florida	228,360	57,491	70,482	102,076	2,072	7,018	467,498
Georgia	552,007	56,122	56,817	7,984	1,253	2,010	676,193
Illinois	724,657	133,201	5,384	1,960	1,174	20	866,396
Indiana	829,988	95,201	59,767	871	775	24	986,626
Iowa	169,039	61,242	19,821	482	346	25	250,954
Kansas	59,567	13,048	36,376	518	302	103	109,915
Kentucky	718,980	25,813	34,214	1,368	510	364	781,249
Louisiana	100,239	159,722	2,373	78,051	455	892	341,731
Maine	15,759	18,519	9,950	3,926	156	150	48,460
Maryland	49,078	34,988	40,854	17,112	608	32	142,672
Massachusetts	16,299	19,622	25,242	29,825	575	93	91,657
Michigan	287,807	76,458	42,066	7,636	1,074	91	415,132
Minnesota	53,596	25,100	14,733	1,342	596	631	95,997
Mississippi	46,432	24,426	6,788	2,094	375	1,051	81,166
Missouri	445,643	78,310	44,550	1,307	765	186	570,761
Nebraska	120,790	6,430	29,571	817	209	105	157,921
New Hampshire	7,290	3,245	7,396	72	142	38	18,183
New Jersey	37,746	6,747	10,715	25,286	772	61	81,327
New York	144,074	58,566	125,187	12,336	1,541	113	341,818
North Carolina	126,620	66,128	22,000	48,861	935	696	265,240
North Dakota	77,383	9,458	6,451	288	76	66	93,722
Ohio	946,667	105,406	19,810	3,456	1,131	22	1,076,493
Oklahoma	156,032	36,912	7,536	341	502	469	201,791
Pennsylvania	966,136	79,142	68,330	4,938	1,135	32	1,119,712
Rhode Island	0	2,743	3,364	2,879	82	1	9,069
South Carolina	149,515	31,452	30,005	22,697	532	646	234,846
South Dakota	13,453	1,698	10,342	65	91	498	26,147
Tennessee	596,987	77,595	32,701	828	795	277	709,182
Texas	327,873	162,915	109,199	37,109	2,409	1,178	640,682
Vermont	0	902	5,381	6	94	49	6,432
Virginia	145,452	69,166	32,904	15,158	883	399	263,963
West Virginia	588,392	41,817	14,583	443	197	215	645,646
Wisconsin	107,365	66,452	6,370	928	646	70	181,830
Grand total	9,243,362	1,802,927	1,116,694	451,705	24,595	19,345	12,658,628

TABLE IV.C–4—2012 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	121,809	74,832	31,958	49,622	82,135	3,814	364,171
Arkansas	43,222	37,479	21,429	48,349	46,959	2,654	200,092
Connecticut	2,770	5,830	12,475	15,865	37,847	14	74,801

TABLE IV.C–4—2012 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Delaware	4,639	5,567	3,248	15,511	10,700	23	39,687
District of Columbia	2	501	1,739	2,704	4,857	0	9,802
Florida	195,673	55,017	29,475	282,147	275,603	25,600	863,515
Georgia	78,011	53,317	38,825	76,901	158,771	7,955	413,780
Illinois	77,920	92,440	47,564	167,046	157,915	71	542,957
Indiana	203,107	73,651	30,125	83,760	114,396	88	505,127
Iowa	66,316	39,301	15,064	72,031	58,920	90	251,721
Kansas	70,823	70,751	42,249	66,897	43,914	378	295,012
Kentucky	149,179	34,875	17,446	72,289	71,284	1,326	346,399
Louisiana	44,773	161,724	27,525	285,562	64,074	3,254	586,912
Maine	3,139	18,309	7,295	13,354	21,896	566	64,559
Maryland	17,376	24,624	21,647	53,580	64,368	137	181,731
Massachusetts	6,312	18,447	34,245	75,149	57,417	341	191,911
Michigan	96,874	93,953	43,392	80,900	163,505	330	478,955
Minnesota	51,285	64,250	56,581	92,080	86,198	2,300	352,694
Mississippi	37,517	52,454	12,151	64,138	52,709	3,833	222,801
Missouri	77,571	38,610	32,731	96,197	108,298	678	354,085
Nebraska	52,820	12,159	13,788	81,177	33,907	381	194,233
New Hampshire	2,514	3,243	11,153	7,308	19,710	137	44,067
New Jersey	15,987	18,996	26,320	81,906	76,979	223	220,410
New York	25,755	55,167	87,776	100,212	154,260	412	423,582
North Carolina	61,643	44,514	18,715	133,476	126,081	11,424	395,854
North Dakota	59,547	7,544	10,018	46,649	12,111	240	136,110
Ohio	159,627	69,075	41,378	133,650	149,134	81	552,945
Oklahoma	86,858	71,808	94,528	43,057	71,207	1,709	369,167
Pennsylvania	193,032	85,168	53,289	92,594	142,217	117	566,418
Rhode Island	221	2,168	2,959	7,468	8,120	4	20,940
South Carolina	47,762	28,953	20,273	63,564	75,994	2,357	238,903
South Dakota	15,493	5,035	5,733	24,117	14,957	1,817	67,151
Tennessee	68,425	59,594	18,573	65,209	126,353	1,012	339,166
Texas	159,738	287,831	274,203	313,204	303,453	4,890	1,343,319
Vermont	0	800	3,406	3,077	10,328	179	17,790
Virginia	36,036	60,101	53,496	79,717	111,583	1,456	342,389
West Virginia	102,725	35,698	14,473	26,040	27,694	785	207,415
Wisconsin	49,351	40,694	21,979	58,951	86,315	256	257,546
Grand Total	2,485,856	1,904,481	1,299,224	3,075,459	3,232,168	80,932	12,078,120

TABLE IV.C–5—2014 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	322,130	69,150	52,313	1,873	605	983	447,053
Arkansas	88,187	13,055	27,256	142	347	728	129,714
Connecticut	5,512	1,834	18,440	1,294	340	4	27,423
Delaware	7,806	10,974	5,857	14,891	101	6	39,635
District of Columbia	0	686	1,559	4	42	0	2,291
Florida	192,903	57,521	70,480	108,579	2,159	7,018	438,658
Georgia	173,210	56,014	56,813	8,263	1,307	2,010	297,618
Illinois	200,475	133,109	5,381	390	1,221	20	340,596
Indiana	804,294	95,037	59,764	193	810	24	960,123
Iowa	163,966	60,195	19,817	85	360	25	244,448
Kansas	65,125	13,048	36,375	54	313	103	115,018
Kentucky	739,592	23,804	34,210	258	528	364	798,755
Louisiana	94,824	151,216	2,372	78,097	470	892	327,871
Maine	11,650	18,520	9,945	4,215	160	150	44,640
Maryland	42,635	34,994	40,851	16,966	631	32	136,109
Massachusetts	16,299	19,624	25,237	32,043	594	93	93,890
Michigan	275,637	76,437	42,066	7,536	1,107	91	402,874
Minnesota	61,447	25,112	14,728	468	618	631	103,005
Mississippi	48,149	24,427	6,785	1,280	385	1,051	82,077
Missouri	500,649	77,086	44,543	214	796	186	623,473
Nebraska	115,695	6,431	29,570	55	217	105	152,072
New Hampshire	6,608	3,246	7,393	45	148	38	17,476
New Jersey	37,669	6,756	10,712	26,589	799	61	82,585
New York	141,354	58,584	125,196	10,853	1,594	113	337,694
North Carolina	140,585	66,046	21,994	52,897	961	696	283,180
North Dakota	80,320	9,458	5,763	35	78	66	95,720
Ohio	841,194	105,123	19,810	2,085	1,171	22	969,405
Oklahoma	165,773	36,924	7,534	45	524	469	211,268
Pennsylvania	972,977	76,256	68,324	4,117	1,169	32	1,122,876

TABLE IV.C–5—2014 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Rhode Island	0	2,745	3,364	3,128	85	1	9,323
South Carolina	156,096	31,453	30,002	24,380	551	646	243,129
South Dakota	13,459	1,699	10,298	22	94	498	26,070
Tennessee	600,066	77,605	32,696	173	829	277	711,647
Texas	373,950	155,720	109,194	36,109	2,511	1,178	678,662
Vermont	0	903	5,380	7	101	49	6,439
Virginia	135,741	69,177	32,899	15,624	918	399	254,758
West Virginia	496,307	41,817	14,581	96	201	215	553,218
Wisconsin	117,253	66,456	6,370	638	675	70	191,461
Grand Total	8,209,536	1,778,244	1,116,600	453,742	25,516	19,345	11,602,982

TABLE IV.C–6—2014 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	118,420	74,622	31,939	45,932	67,011	3,814	341,738
Arkansas	44,792	37,491	21,422	44,299	38,965	2,654	189,623
Connecticut	2,821	5,854	12,451	14,410	31,534	14	67,084
Delaware	4,513	5,567	3,245	15,270	8,736	23	37,353
District of Columbia	1	501	1,738	2,398	3,929	0	8,568
Florida	180,801	55,343	29,457	278,920	225,478	25,600	795,599
Georgia	48,091	53,557	38,797	71,011	130,240	7,955	349,650
Illinois	80,228	93,059	47,540	151,373	131,403	71	503,676
Indiana	200,899	73,523	30,107	76,024	94,217	88	474,858
Iowa	68,146	38,831	15,038	65,751	48,836	90	236,692
Kansas	78,920	70,730	42,238	61,613	35,950	378	289,829
Kentucky	148,509	34,979	17,413	65,805	57,759	1,326	325,791
Louisiana	45,457	161,766	27,515	274,697	52,360	3,254	565,049
Maine	2,535	18,316	7,257	13,169	18,061	566	59,903
Maryland	19,990	24,687	21,626	52,501	53,040	137	171,980
Massachusetts	6,619	18,527	34,207	75,654	46,748	341	182,095
Michigan	97,455	94,079	43,360	73,939	135,806	330	444,969
Minnesota	51,859	64,372	56,545	84,040	71,161	2,300	330,278
Mississippi	37,142	52,440	12,133	58,559	42,525	3,833	206,633
Missouri	82,979	38,744	32,677	88,233	90,001	678	333,312
Nebraska	52,970	12,173	13,779	75,252	27,856	381	182,410
New Hampshire	2,515	3,255	11,129	6,587	16,260	137	39,884
New Jersey	16,268	19,089	26,298	78,875	63,254	223	204,007
New York	28,350	55,359	87,826	92,841	129,376	412	394,165
North Carolina	61,747	44,573	18,669	133,455	104,150	11,424	374,018
North Dakota	59,556	7,549	3,969	42,972	9,925	240	130,252
Ohio	164,945	69,157	41,352	120,900	122,426	81	518,861
Oklahoma	81,122	72,525	94,513	39,539	58,382	1,709	347,790
Pennsylvania	196,151	84,111	53,246	83,885	118,122	117	535,631
Rhode Island	281	2,186	2,957	7,384	6,772	4	19,585
South Carolina	47,512	28,969	20,271	62,400	62,996	2,357	224,505
South Dakota	15,514	5,039	5,157	22,021	12,254	1,817	62,368
Tennessee	68,779	59,694	18,542	59,145	104,711	1,012	311,882
Texas	166,177	282,509	274,163	289,605	241,009	4,890	1,258,354
Vermont	0	803	3,397	2,771	8,563	179	15,713
Virginia	32,115	60,216	53,464	75,461	92,291	1,456	315,002
West Virginia	100,103	35,700	14,459	23,798	22,863	785	197,708
Wisconsin	53,774	40,729	21,974	53,848	71,163	256	241,743
Grand total	2,468,057	1,900,624	1,298,473	2,884,338	2,656,134	80,932	11,288,558

Development of Future-Year Emissions Inventories for Electric Generating Units

Future year 2012 and 2014 base case EGU emissions used for the air quality modeling runs that predicted ozone and $PM_{2.5}$ were obtained from version 3.02 EISA of the IPM (*http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html*). The IPM is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector; version 3.02 EISA features an updated Title IV SO_2 allowance bank assumption, reflects state rules and consent decrees through February 3, 2009, and incorporates updates related to the Energy Independence and Security Act of 2007. Units with advanced controls (*e.g.*, scrubber, SCR) that were not required to run for compliance with Title IV, New Source Review (NSR), state settlements, or state-specific rules were allowed in IPM to decide on the basis of economic efficiency whether to operate those controls. Further details on the EGU emissions inventory used for this proposal can be found in the IPM Documentation. Also note that as explained in section IV.A.3, the baseline used in this analysis assumes no CAIR. If EPA's base case analysis were to

assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. As explained in that section, EPA believes that this is the most appropriate baseline to use for purposes of determining whether an upwind state has an impact on a downwind monitoring site in violation of section 110(a)(2)(D).

Development of Future-Year Emissions Inventories for Mobile Inventories

Mobile source inventories of onroad and nonroad mobile emissions were created for 2012 and 2015 using a combination of the NMIM and draft MOVES models. Mobile source emissions were further interpolated between 2012 and 2015 to estimate 2014 emissions. Emissions for these years reflect onroad mobile control programs including the Light-Duty Vehicle Tier 2 Rule, the Onroad Heavy-Duty Rule, and the Mobile Source Air Toxics (MSAT) final rule. Nonroad mobile emissions reductions for these years include reductions to locomotives, various nonroad engines including diesel engines and various marine engine types, fuel sulfur content, and evaporative emissions standards. A more comprehensive list of control programs included for mobile sources is available in the EITSD.

The onroad emissions were primarily based on the NMIM monthly, county, process level emissions. For both 2012 and 2015, emissions from onroad gasoline sources were augmented with emissions based on the same preliminary version of MOVES as was used for 2005. MOVES-based emissions were computed for CO, NO_X, VOC, $PM_{2.5}$, and PM_{10}. The same MOVES-based $PM_{2.5}$ temperature adjustment factors were also applied as in 2005.

Nonroad mobile emissions were created only with NMIM using a consistent approach as was used for 2005, but emissions were calculated using NMIM future-year equipment population estimates and control programs for 2012 and 2014. Emissions from 2012 and 2015 were used for locomotives and category 1 and 2 (C1 and C2) commercial marine vessels, based on emissions published in OTAQ's Locomotive Marine Rule, Regulatory Impact Assessment, Chapter 3. For category 3 (C3) commercial marine vessels, a coordination strategy of emissions reductions is ongoing that includes NO_X, VOC, and CO reductions for new C3 engines as early as 2011 and fuel sulfur limits that could go into affect as early as 2012. However, given the uncertainty about the timing for parts of these emissions reductions and the fact that the 2012 modeling was conducted well in advance of the December 2009 publication of the rule, we have not used the controlled emissions in modeling supporting this proposal.

Development of Future-Year Emissions Inventories for Other Inventory Sources

Other inventory sources include nonEGU point sources, stationary nonpoint sources, and emissions in Canada and Mexico. Emissions from Canada and Mexico for all source sectors (including EGUs) in these countries were held constant for all cases. This approach reflects the unavailability of future-year emissions from Canada and Mexico for the future years of interest in time to support the modeling for this proposal.

The future year emissions for other sectors are described next. For all sector projections, EPA seeks comment on growth and control approaches, particularly where a control measure has not been included. The EITSD provides more details on these projections for additional review and we have included in the EITSD a table for the public to provide more detailed control data to EPA.

For nonEGU point sources, emissions were projected by including emissions reductions and increases from a variety of sources. For nonEGUs, emissions were not grown using economic growth projections and emissions reductions were applied through plant closures, refinery and other consent decrees, and reductions stemming from several MACT standards. Since aircraft at airports were treated as point emissions sources in the 2005 NEI v2, we also applied projection factors based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast (TAF) system, published December 2008. Controls from the NO_X SIP Call were assumed to have been implemented by 2005 and captured in the 2005 NEI v2.

For stationary nonpoint sources, refueling emissions were projected using the refueling results from the NMIM runs performed for the onroad mobile sector. Portable fuel container emissions were projected using estimates from previous OTAQ rulemaking inventories. Emissions of ammonia and dust from animal operations were projected based on animal population data from the Department of Agriculture and EPA. Residential wood combustion was projected by replacement of obsolete woodstoves with new woodstoves and a 1 percent annual increase in fireplaces. Landfill emissions were projected using MACT controls. All other nonpoint sources were held constant between 2005 and the future years.

(3) Preparation of Emissions for AQ Modeling

The annual and summer day emissions inventory files were processed through the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 2.6 to produce the gridded model-ready emissions for input to CAMx. Emissions processing using SMOKE was performed to create the hourly, gridded data of CAMx species required for air quality modeling for all sectors, including biogenic emissions. Additional information on the development of the emissions data sets for modeling is provided in the EITSD. Details about preparation of emissions for contribution modeling are described in the Transport Rule AQ Modeling TSD.

c. Preparation of Meteorological and Other Air Quality Modeling Inputs

The gridded meteorological input data for the entire year of 2005 were derived from simulations of the Pennsylvania State University/National Center for Atmospheric Research Mesoscale Model. This model, commonly referred to as MM5, is a limited-area, nonhydrostatic, terrain-following system that solves for the full set of physical and thermodynamic equations which govern atmospheric motions.[26] The meteorological outputs from MM5 were processed to create model-ready inputs for CMAQ using the MM5-to-CAMx preprocessor (ref CAMx user's guide).

The 2005 MM5 meteorological predictions for selected variables were compared to measurements as part of several performance evaluations of the predicted data. The evaluation approach included a combination of qualitative and quantitative analyses to assess the adequacy of the MM5 simulated fields. The qualitative aspects involved comparisons of the model-estimated synoptic patterns against observed patterns from historical weather chart archives. Additionally, the evaluations compared spatial patterns of monthly average rainfall and monthly maximum planetary boundary layer (PBL) heights. The operational evaluation included

[26] Grell, G., J. Dudhia, and D. Stauffer, 1994: A Description of the Fifth-Generation Penn State/NCAR Mesoscale Model (MM5), NCAR/TN–398+STR., 138 pp, National Center for Atmospheric Research, Boulder CO.

statistical comparisons of model/observed pairs (*e.g.*, mean normalized bias, mean normalized error, index of agreement, root mean square errors, etc.) for multiple meteorological parameters. For this portion of the evaluation, five meteorological parameters were investigated: Temperature, humidity, shortwave downward radiation, wind speed, and wind direction. The three individual MM5 evaluations are described elsewhere.[27] [28] [29] It was ultimately determined that the bias and error values associated with the 2005 meteorological data were generally within the range of past meteorological modeling results that have been used for air quality applications. Additional details on the meteorological inputs can be found in the AQMTSD.

As noted previously, the CAMx simulations for this proposal were performed using a spatial resolution of 12 x 12 km. The concentrations of pollutants transported into this eastern U.S. modeling region were obtained from air quality model simulations performed at coarser 36 x 36 km resolution for a modeling domain covering the lower 48 states and portions of northern Mexico and southern Canada. The 12 x 12 km model simulations were also initialized with air quality predictions from the coarse scale modeling. Pollutant concentrations at the boundaries of the coarse scale modeling domain were obtained from a three-dimensional global atmospheric chemistry model, the GEOSChem [30] model (standard version 7–04–11 [31]). The global GEOSChem model simulates atmospheric chemical and physical processes driven by assimilated meteorological observations from the NASA's Goddard Earth Observing System (GEOS). This model was run for 2005 with a grid resolution of 2.0 degrees x 2.5 degrees (latitude-longitude). The predictions were used to provide one-way dynamic boundary conditions at three-hour intervals and an initial concentration field for the coarse scale simulations.

d. Model Performance Evaluation for Ozone and $PM_{2.5}$

The 2005 base year model predictions for ozone and fine particulate sulfate, nitrate, organic carbon, elemental carbon, and crustal material were compared to measured concentrations in order to evaluate the performance of the modeling platform for replicating observed concentrations. This evaluation was comprised principally of statistical assessments of paired modeled and observed data. Details on the evaluation methodology and the calculation of performance statistics are provided in the AQMTSD. The results indicate that, overall, the predicted patterns and day-to-day variations in regional ozone levels are similar to what was observed with measured data. The normalized mean bias for 8-hour daily maximum ozone concentrations was −2.9 percent and the normalized mean error was 13.2 percent for the months of May through September 2005, based on an aggregate of observed-predicted pairs within the 12 km modeling domain. The two $PM_{2.5}$ species that are most relevant for this proposal are sulfate and nitrate. For the summer months of June though August, when observed sulfate concentrations are highest in the East, the model predictions of 24-hour average sulfate were lower than the corresponding measured values by 7 percent at urban sites and by 9 to 10 percent at rural sites in the IMPROVE [32] and CASTNET [33] monitoring networks, respectively. For the winter months of December through February, when observed nitrate concentrations are highest in the East, the model predictions of 24-hour average particulate nitrate were lower than the corresponding measured values by 12 percent at urban sites and by 4 percent at rural sites in the IMPROVE monitoring network. The model performance statistics by season for ozone and $PM_{2.5}$ component species are provided in the AQMTSD.

2. How did EPA project future nonattainment and maintenance for annual $PM_{2.5}$, 25-Hour $PM_{2.5}$, and 8-hour ozone?

In this section we describe the approach for projecting future concentrations of ozone and $PM_{2.5}$ to identify locations that are expected to be nonattainment or have a maintenance problem in 2012. The nonattainment and maintenance locations are based on projections of future air quality at existing ozone and $PM_{2.5}$ monitoring sites. These sites are used as the "receptors" for quantifying the contributions of emissions in upwind states to nonattainment and maintenance in downwind locations. For this analysis we are using the air quality modeling results in a "relative" sense to project future concentrations. In this approach, the ratio of future year model predictions to base year model predictions are used to adjust ambient measured data up or down depending on the relative (percent) change in model predictions for each location.

a. How did EPA process ambient ozone and $PM_{2.5}$ data for the purpose of projecting future year concentrations?

In this analysis we use measurements of ambient ozone and $PM_{2.5}$ data that come from monitoring networks consisting of more than one thousand ozone monitors and one thousand $PM_{2.5}$ monitors located across the country. The monitors are sited according to the spatial and temporal nature of ozone and $PM_{2.5}$, and to best represent the actual air quality in the United States. The ambient data used in this analysis were obtained from EPA's Air Quality System (AQS).

In order to use the ambient data, the raw measurements must be processed into a form pertinent for useful interpretations. For this action, the ozone data were processed consistent with the formats associated with the NAAQS for ozone. The resulting estimates are used to indicate the level of air quality relative to the NAAQS. For ozone air quality indicators, we developed estimates for the 1997 8-hour ozone standard. The level of the 1997 8-hour O3 NAAQS is 0.08 ppm. The 8-hour ozone standard is not met if the 3-year average of the annual 4th highest daily maximum 8-hour O3 concentration is greater than 0.08 ppm (0.085 ppm when rounded up). This 3-year average is referred to as the design value.

The $PM_{2.5}$ ambient data were processed consistent with the formats associated with the NAAQS for $PM_{2.5}$. The resulting estimates are used to

[27] Baker K. and P. Dolwick. Meteorological Modeling Performance Evaluation for the Annual 2005 Eastern U.S. 12-km Domain Simulation, USEPA/OAQPS, February 2, 2009.

[28] Baker K. and P. Dolwick. Meteorological Modeling Performance Evaluation for the Annual 2005 Western U.S. 12-km Domain Simulation, USEPA/OAQPS, February 2, 2009.

[29] Baker K. and P. Dolwick. Meteorological Modeling Performance Evaluation for the Annual 2005 Continental U.S. 36-km Domain Simulation, USEPA/OAQPS, February 2, 2009.

[30] Yantosca, B., 2006. GEOS–CHEMv7–04–11 User's Guide, Atmospheric Chemistry Modeling Group, Harvard University, Cambridge, MA, March 05, 2006.

[31] Henze, D.K., J.H. Seinfeld, N.L. Ng, J.H. Kroll, T-M. Fu, D.J. Jacob, C.L. Heald, 2008. Global modeling of secondary organic aerosol formation from aromatic hydrocarbons: high-vs. low-yield pathways. *Atmos. Chem. Phys.*, 8, 2405–2420.

[32] *I*nteragency *M*onitoring of *PRO*tected *V*isual *E*nvironments (IMPROVE). Debell, L.J., et. al. Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States: Report IV. November 2006.

[33] Clean Air Status and Trends Network (CASTNET) 2005 Annual Report. EPA Office of Air and Radiation, Clean Air Markets Division. Washington, DC. December 2006.

indicate the level of air quality relative to the NAAQS. For $PM_{2.5}$, we evaluated concentrations of both the annual average $PM_{2.5}$ NAAQS and the 24-hour $PM_{2.5}$ NAAQS. The annual $PM_{2.5}$ standard is met when the 3-year average of the annual mean concentration is 15.0 $\mu g/m^3$ or less. The 3-year average annual mean concentration is computed at each site by averaging the daily Federal Reference Method (FRM) samples by quarter, averaging these quarterly averages to obtain an annual average, and then averaging the three annual averages. The 3-year average annual mean concentration is referred to as the annual design value.

The 24-hour average standard is met when the 3-year average of the annual 98th percentile $PM_{2.5}$ concentration is 35 $\mu g/m^3$ or less. The 3-year average mean 98th percentile concentration is computed at each site by averaging the 3 individual annual 98th percentile values at each site. The 3-year average 98th percentile concentration is referred to as the 24-hour average design value.

As described later, the approach for projecting future ozone and $PM_{2.5}$ design values involved the projection of an average of up to 3 design value periods which include the years 2003–2007 (design values for 2003–2005, 2004–2006, and 2005–2007). The average of the 3 design values creates a "5-year weighted average" value. The 5-year weighted average values were then projected to the future years that were analyzed for this proposed rule. The 2003–2005, 2004–2006, and 2005–2007 design values are accessible at *http://www.epagov/airtrends/values.html.*

The procedures for projecting annual average $PM_{2.5}$ and 8-hour ozone conform to the methodology in the final attainment demonstration modeling guidance [34]. In the CAIR analysis, EPA did not project 24-hour $PM_{2.5}$ design values [35]. The analysis for this proposed rule, in contrast, uses the 24-hour $PM_{2.5}$ methodology outlined in the modeling guidance.

b. Projection of Future Annual and 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

Annual $PM_{2.5}$ modeling was performed for the 2005 base year emissions and for the 2012 base case as part of the approach for projecting which locations (*i.e.*, monitoring sites) are expected to be in nonattainment and/or have difficulty maintaining the $PM_{2.5}$ standards in 2012. We refer to these areas as nonattainment sites and maintenance sites respectively.

In general, the projection methodology involves using the model in a relative sense to estimate the change in $PM_{2.5}$ between 2005 and the future 2012 base case as recommended in the modeling guidance. Rather than use the absolute model-predicted future year ozone and $PM_{2.5}$ concentrations, the base year and future year predictions are used to calculate a (relative) percent change in ozone and $PM_{2.5}$ concentrations. For a particular location, the percent change in modeled concentration is multiplied by the corresponding observed base period ambient concentration to estimate the future year design value for that location. The use of observed ambient data as part of the calculation helps to constrain the future year design value predictions, even if the absolute model concentrations are over-predicted or under-predicted.

Concentrations of $PM_{2.5}$ in 2012 were estimated by applying the 2005 to 2012 relative change in model-predicted $PM_{2.5}$ species to the (2003–2007) $PM_{2.5}$ design values. The choice of base period design values is consistent with EPA's modeling guidance which recommends using the average of the three design value periods centered about the emissions projection year. Since 2005 was the base emissions year, we used the design value for 2003–2005, 2004–2006, and 2005–2007 to represent the base period $PM_{2.5}$ concentrations. For each FRM $PM_{2.5}$ monitoring site, all valid design values (up to 3) from this period were averaged together. Since 2005 is included in all three design value periods, this has the effect of creating a 5-year weighted average, where the middle year is weighted 3 times, the 2nd and 4th years are weighted twice, and the 1st and 5th years are weighted once. We refer to this as the 5-year weighted average concentration.

The 5-year weighted average concentrations were used to project concentrations for the 2012 base case in order to determine which monitoring sites are expected to be nonattainment in this future year. We projected 2012 design values for each of 3 year periods (*i.e.*, 2003–2005, 2004–2006, and 2003–2007) and used the highest of these projections to determine which sites are expected to have maintenance problems in 2012.

For the analysis of both nonattainment and maintenance, monitoring sites were included in the analysis if they had at least one complete design value in the 2003–2007 period.[36] There were 721 monitoring sites in the 12 km modeling domain which had at least one complete design value period for the annual $PM_{2.5}$ NAAQS, and 736 sites which met this criteria for the 24-hour NAAQS.[37]

EPA followed the procedures recommended in the modeling guidance for projecting $PM_{2.5}$ by projecting individual $PM_{2.5}$ component species and then summing these to calculate the concentration of total $PM_{2.5}$. The model predictions are used in a relative sense to estimate changes expected to occur in each of the major $PM_{2.5}$ species. The $PM_{2.5}$ species are sulfate, nitrate, ammonium, particle bound water, elemental carbon, salt, other primary $PM_{2.5}$, and organic aerosol mass by difference. Organic aerosol mass by difference is defined as the difference between FRM $PM_{2.5}$ and the sum of the other components. The procedure for calculating future year $PM_{2.5}$ design values is called the SMAT. The SMAT approach is codified in a software tool available from EPA called MATS. The software (including documentation) is available at: *http://www.epa.gov/scram001/modelingapps_mats.htm*.

(1) Methodology for Projecting Future Annual $PM_{2.5}$ Nonattainment and Maintenance

The following is a brief summary of the future year annual $PM_{2.5}$ calculations. Additional details are provided in the modeling guidance, MATS documentation, and the AQMTSD.

We are using the base period (*i.e.*, 2003 2007) FRM data for projecting future design values since these data are used to determine attainment status. In order to apply SMAT to the FRM data, information on $PM_{2.5}$ speciation is needed for the location of each FRM monitoring site. Since co-located $PM_{2.5}$ speciation data are only available at about 15 percent of FRM monitoring sites, spatial interpolation techniques are used to calculate species concentrations for each FRM monitoring site. Speciation data from the IMPROVE and Chemical Speciation Network

[34] U.S. EPA, 2007: Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze; Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[35] CAIR was promulgated in 2005 before the 35 ug/m^3 $PM_{2.5}$ NAAQS was finalized in 2006. Since there were no violations in the eastern United States (base or future year) of the 1997 65 ug/m3 NAAQS, it was not necessary to project 24 $PM_{2.5}$ values as part of the modeling for CAIR.

[36] If there is only one complete design value, then the nonattainment and maintenance design values are the same.

[37] Design values were only used if they were deemed to be officially complete based on CFR 40 part 50 appendix N. The completeness criteria for the annual and 24-hour $PM_{2.5}$ NAAQS are different. Therefore, there are fewer complete sites for the annual NAAQS.

(CSN) were interpolated to each FRM monitor location using the Voronoi Neighbor Averaging (VNA) technique (using MATS). Additional information on the VNA interpolation techniques and data handling procedures can be found in the MATS User's Guide. After the species fractions are calculated for each FRM site, the following procedures were used to estimate future year design values:

Step 1: Calculate quarterly mean concentrations for each of the major species components of $PM_{2.5}$ (*i.e.*, sulfate, nitrate, ammonium, elemental carbon, organic carbon mass, particle bound water, salt, and blank mass). This is done by multiplying the monitored quarterly mean concentration of FRM-derived total $PM_{2.5}$ by the monitored fractional composition of $PM_{2.5}$ species for each quarter averaged over 3 years [38] (*e.g.*, 20 percent sulfate fraction multiplied by 15 $\mu g/m^3$ $PM_{2.5}$ equals 3 $\mu g/m^3$ sulfate).

Step 2: For each quarter, calculate the ratio of future year to base year model predictions for each of the component species. The result is a set of species-specific relative response factors (RRF) (*e.g.*, assume that the model-predicted 2005 base year sulfate for a particular location is 10.0 $\mu g/m^3$ and the 2012 future concentration is 8.0 $\mu g/m^3$, then RRF for sulfate is 0.8). The RRFs are calculated based on the modeled concentrations averaged over the nine grid cells [39] centered at the location of the monitor.

Step 3: For each quarter and each of the species, multiply the base year quarterly mean component concentration (Step 1) by the species-specific RRF obtained in Step 2. This results in an estimated future year quarterly mean concentration for each species (*e.g.*, 3 $\mu g/m^3$ sulfate multiplied by 0.8 equals a future sulfate concentration of 2.4 $\mu g/m^3$).

Step 4: The future year concentrations for the remaining species are then calculated.[40] The future year ammonium is calculated based on the calculated future year sulfate and nitrate concentrations, using a constant value for the degree of neutralization of sulfate (from the ambient data). The future year particle bound water concentration is calculated from an empirical formula. The inputs to the formula are the future year concentrations of sulfate, nitrate, and ammonium (from step 3).

Step 5: Average the four quarterly mean future concentrations to obtain the future year annual design value concentration for each of the component species. Sum the species concentrations to obtain the future year annual average design value for $PM_{2.5}$.

Step 6: Calculate the maximum future design value by processing each of the three base design value periods (2003–2005, 2004–2006, and 2005–2007) separately. The highest of the three future values is the maximum design value. The maximum design values are used to determine future year maintenance sites.

The preceding procedures for determining future year $PM_{2.5}$ concentrations were applied for each FRM site. The calculated annual $PM_{2.5}$ design values are truncated (*i.e.*, discarded) after the second decimal place.[41] This is consistent with the truncation and rounding procedures for the annual $PM_{2.5}$ NAAQS. Any value that is greater than or equal to 15.05 $\mu g/m^3$ is rounded to 15.1 $\mu g/m^3$ and is considered to be violating the NAAQS. Thus, sites with future year annual $PM_{2.5}$ design values of 15.05 $\mu g/m^3$ or greater, based on the projection of 5-year weighted average concentrations, are predicted to be nonattainment sites. Sites with future year maximum design values of 15.05 $\mu g/m^3$ or greater are predicted to be maintenance sites. Note that nonattainment sites are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. For ease of reference we use the term "nonattainment sites" to refer to those sites that are projected to exceed the NAAQS based on both the average and maximum design values. Those sites that are projected to be attainment based on the average design value but exceed the NAAQS based on the maximum design value are referred to as maintenance sites. The monitoring sites that we project to be nonattainment and/or maintenance for the annual $PM_{2.5}$ NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of the annual $PM_{2.5}$ NAAQS as part of this proposal.

Table IV.C–7 contains the 2003–2007 base case period average and maximum annual $PM_{2.5}$ design values and the corresponding 2012 base case average and maximum design values for sites projected to be nonattainment of the annual $PM_{2.5}$ NAAQS in 2012. Table IV.C–8 contains this same information for projected 2012 maintenance sites.

TABLE IV.C–7—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES ($\mu g/m^3$) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
10730023	Alabama	Jefferson	18.48	18.67	17.15	17.33
10732003	Alabama	Jefferson	17.07	17.45	15.99	16.35
130210007	Georgia	Bibb	16.47	16.78	15.33	15.62
130630091	Georgia	Clayton	16.47	16.71	15.07	15.29
131210039	Georgia	Fulton	17.43	17.47	16.01	16.04
170310052	Illinois	Cook	15.75	16.02	15.16	15.43
171191007	Illinois	Madison	16.72	17.01	16.56	16.85
171630010	Illinois	Saint Clair	15.58	15.74	15.48	15.63
180190006	Indiana	Clark	16.40	16.60	15.96	16.16
180372001	Indiana	Dubois	15.18	15.68	15.07	15.57
180970078	Indiana	Marion	15.26	15.43	15.18	15.36

[38] For this analysis, species fractions were calculated using an average of FRM and speciation data for the 2004–2006 time period. This was deemed to be representative of the 2005 base year.

[39] The modeling guidance recommends calculating annual $PM_{2.5}$ RRFs using a 3 x 3 grid cell array (9 grid cells) for a model resolution of 12km.

[40] All of the calculations and assumptions are consistent with the default MATS settings (as described in the MATS user's guide and the photochemical modeling guidance). Additionally, we did not explicitly model salt and therefore the salt concentration was held constant from the base to future. Blank mass was assumed to be a constant mass of 0.5 $\mu g/m^3$ in both the base and future year.

[41] For example, a calculated annual average concentration of 14.94753 * * * becomes 14.94 when digits beyond two places to the right are truncated.

TABLE IV.C–7—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES ($\mu G/M^3$) AT PROJECTED NONATTAINMENT SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
180970081	Indiana	Marion	16.05	16.36	15.93	16.25
180970083	Indiana	Marion	15.90	16.27	15.77	16.15
211110043	Kentucky	Jefferson	15.53	15.75	15.19	15.41
261630015	Michigan	Wayne	15.88	16.40	15.05	15.55
261630033	Michigan	Wayne	17.50	18.16	16.57	17.19
390170016	Ohio	Butler	15.74	16.11	15.25	15.61
390350038	Ohio	Cuyahoga	17.37	18.1	16.26	16.95
390350045	Ohio	Cuyahoga	16.47	16.98	15.42	15.91
390350060	Ohio	Cuyahoga	17.11	17.66	16.02	16.55
390610014	Ohio	Hamilton	17.29	17.53	16.69	16.93
390610042	Ohio	Hamilton	16.85	17.25	16.33	16.71
390610043	Ohio	Hamilton	15.55	15.82	15.05	15.32
390617001	Ohio	Hamilton	16.17	16.56	15.65	16.03
390618001	Ohio	Hamilton	17.54	17.90	16.93	17.27
420030064	Pennsylvania	Allegheny	20.31	20.75	18.90	19.31
420031301	Pennsylvania	Allegheny	16.26	16.57	15.13	15.42
420070014	Pennsylvania	Beaver	16.38	16.45	15.23	15.30
420710007	Pennsylvania	Lancaster	16.55	17.46	15.19	16.01
421330008	Pennsylvania	York	16.52	17.25	15.25	15.94
540110006	West Virginia	Cabell	16.30	16.57	15.25	15.50
540391005	West Virginia	Kanawha	16.52	16.59	15.28	15.34

TABLE IV.C–8—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES (μ/M^3) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
170313301	Illinois	Cook	15.24	15.59	14.73	15.06
170316005	Illinois	Cook	15.48	16.07	14.92	15.48
211110044	Kentucky	Jefferson	15.31	15.47	14.93	15.09
360610056	New York	New York	16.18	17.02	14.98	15.74
390350027	Ohio	Cuyahoga	15.46	16.13	14.50	15.13
390350065	Ohio	Cuyahoga	15.97	16.44	14.96	15.40
390610040	Ohio	Hamilton	15.50	15.88	15.03	15.40
390811001	Ohio	Jefferson	16.51	17.17	14.95	15.54
391130032	Ohio	Montgomery	15.54	15.92	15.01	15.37
391510017	Ohio	Stark	16.15	16.59	14.99	15.40
420110011	Pennsylvania	Berks	15.82	16.19	14.77	15.11
482011035	Texas	Harris	15.42	15.84	14.74	15.14
540030003	West Virginia	Berkeley	15.93	16.19	14.95	15.20
540090005	West Virginia	Brooke	16.52	16.80	14.95	15.22
540291004	West Virginia	Hancock	15.76	16.64	14.34	15.15
540490006	West Virginia	Marion	15.03	15.25	14.96	15.18

(2) Methodology for Projecting Future 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

The following is a brief summary of the procedures used for calculating future year 24-hour $PM_{2.5}$ design values. Additional details are provided in the modeling guidance, MATS documentation, and the AQMTSD. Similar to the annual $PM_{2.5}$ calculations, we are using the 2003–2007 base period FRM data for projecting future year design values. The 24-hour $PM_{2.5}$ calculations are computationally similar to the annual average calculations. The main difference is that the base period 24-hour 98th percentile $PM_{2.5}$ concentrations are projected to the future year, instead of the annual average concentrations. Also, the $PM_{2.5}$ species fractions and relative response factors are calculated from observed and modeled high concentration days, instead of quarterly average data.

Both the annual $PM_{2.5}$ and 24-hour $PM_{2.5}$ calculations are performed on a calendar quarter basis. Since all years and quarters are averaged together in the annual $PM_{2.5}$ calculations, the individual years can be averaged together early in the calculations. However, in the 24-hour $PM_{2.5}$ calculations, only the high quarter from each year is used in the final calculations. This represents the 98th percentile value, which can come from any of the 4 quarters in any year. Therefore all quarters and years must be carried through to near the end of the calculations when the individual future year high quarter values are selected. To calculate final future year design values, the high quarter for each year is identified and then a five year weighted average of the high quarters for each site was calculated to derive the future year design value.

The following are the steps followed for calculating the 2012 base case 24-hour $PM_{2.5}$ design values:

Step 1: At each FRM monitoring site, we identify the maximum 24-hour $PM_{2.5}$ concentration in each quarter that is less

than or equal to the 98th percentile value over the entire year. This results in a data set for each year (for up to 5 years) for each site containing one quarter with the observed 98th percentile value and three quarters with the maximum highest values from each quarter that are less than or equal to the 98th percentile value for the year. All 20 quarters (*i.e.*, 4 quarters in each of 5 years) of data are carried through the calculations until the high future year quarter value is identified in step 6.

Step 2: In this step we calculate quarterly ambient concentrations on "high"[42] days for each of the major component species of $PM_{2.5}$ (sulfate, nitrate, ammonium, elemental carbon, organic carbon mass, particle bound water, salt, and blank mass). This calculation is performed by multiplying the monitored concentrations of FRM-derived total $PM_{2.5}$ mass on the 10 percent highest days from each quarter, by the monitored fractional composition of $PM_{2.5}$ species on the 10 percent highest $PM_{2.5}$ days for each quarter, averaged over 3 years[43] (*e.g.*, 20 percent sulfate fraction multiplied by 40 $\mu g/m^3$ $PM_{2.5}$ equals 8 $\mu g/m^3$ sulfate).

Step 3: For each quarter, we calculate the ratio of future year (*i.e.*, 2012) to base year (*i.e.*, 2005) predictions for each component species for the top 10 percent of days based on predicted concentrations of 24-hour $PM_{2.5}$. The result is a set of species-specific relative response factors (RRF) for the high $PM_{2.5}$ days in each quarter (*e.g.*, assume that the 2005 predicted sulfate concentration on the 10 percent highest $PM_{2.5}$ days for a quarter for a particular location is 20 $\mu g/m^3$ and the 2012 base case concentration is 16 $\mu g/m^3$, then RRF for sulfate is 0.8). The RRFs are calculated based on the modeled concentrations at the single grid cell where the monitor is located.

Step 4: For each quarter, we multiply the quarterly species concentration (step 2) by the quarterly[44] species-specific RRF obtained in step 3. This leads to an estimated future quarterly concentration for each component. (*e.g.*, 21.0 $\mu g/m^3$ nitrate $\times$ 0.75 = future nitrate of 15.75 $\mu g/m^3$).

Step 5: The future year concentrations for the remaining species are then calculated.[45] The future year ammonium is calculated based on the calculated future year sulfate and nitrate concentrations, using a constant value for the degree of neutralization of sulfate (from the ambient data). The future year particle bound water concentration is calculated from an empirical formula. The inputs to the formula are the calculated future year concentrations of sulfate, nitrate, and ammonium (from step 4).

Step 6: We sum the species concentrations to obtain quarterly $PM_{2.5}$ values. This step is repeated for each quarter and for each of the 5 years of ambient data. The highest daily value (from the 4 quarterly values) for each year at each monitor is considered to be the estimated future year 98th percentile 24-hour design value for that year.

Step 7: The estimated 98th percentile values for each of the 5 years are averaged over 3 year intervals to create the 3 year average design values. These design values are averaged to create a 5 year weighted average for each monitoring site.

Step 8: The maximum future design value is calculated by following the previous steps for each of the three base design value periods (2003–2005, 2004–2006, and 2005–2007) separately. The highest of the three future values is the maximum design value. This maximum value is used to identify the 24-hour $PM_{2.5}$ maintenance receptors.

The preceding procedures for determining future year 24-hour $PM_{2.5}$ concentrations were applied for each FRM site. The 24-hour $PM_{2.5}$ design values are truncated after the first decimal place. This approach is consistent with the truncation and rounding procedures for the 24-hour $PM_{2.5}$ NAAQS. Any value that is greater than or equal to 35.5 $\mu g/m^3$ is rounded to 36 $\mu g/m^3$ and is violating the NAAQS. Sites with future year 5 year weighted average design values of 35.5 $\mu g/m^3$ or greater, based on the projection of 5-year weighted average concentrations, are predicted to be nonattainment. Sites with future year maximum design values of 35.5 $\mu g/m^3$ or greater are predicted to be maintenance sites. Note that nonattainment sites for the 24-hour NAAQS are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. For ease of reference we use the term "nonattainment sites" to refer to those sites that are projected to exceed the NAAQS based on both the average and maximum design values. Those sites that are projected to be attainment based on the average design value but exceed the NAAQS based on the maximum design value are referred to as maintenance sites. The monitoring sites that we project to be nonattainment and/or maintenance for the 24-hour $PM_{2.5}$ NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of 24-hour $PM_{2.5}$ NAAQS as part of this proposal.

Table IV.C–9 contains the 2003–2007 base period average and maximum 24-hour $PM_{2.5}$ design values and the 2012 base case average and maximum design values for sites projected to be 2012 nonattainment of the 24-hour $PM_{2.5}$ NAAQS in 2012. Table IV.C–10 contains this same information for projected 2012 24-hour maintenance sites.

TABLE IV.C–9—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES ($\mu g/m^3$) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
10730023	Alabama	Jefferson	44.0	44.2	40.0	40.7
10732003	Alabama	Jefferson	40.3	40.8	38.1	38.9
90091123	Connecticut	New Haven	38.3	40.3	35.7	36.6
170310052	Illinois	Cook	40.2	41.4	38.5	39.7

[42] High ambient data and model days were defined as the top 10 percent days in each quarter based on 24-hour concentrations of $PM_{2.5}$.

[43] For this analysis, species fractions were calculated using an average of FRM and speciation data for the 2004–2006 time period. This was deemed to be representative of the 2005 modeling year.

[44] Since there is only one modeled base year, there are a single set of four quarterly RRFs. The modeled quarterly RRF for quarter 1 is multiplied by the ambient data for quarter 1 for each of the 5 years of ambient data. The same procedure is applied for the other 3 quarters.

[45] All of the calculations and assumptions are consistent with the default MATS settings (as described in the MATS user's guide and the photochemical modeling guidance). Additionally, we did not explicitly model salt and therefore the salt concentration was held constant from the base to future. Blank mass was assumed to be a constant mass of 0.5 ug/m^3 in both the base and future year.

TABLE IV.C–9—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES ($\mu g/m^3$) AT PROJECTED NONATTAINMENT SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
170310057	Illinois	Cook	37.3	38.6	35.7	37.0
170310076	Illinois	Cook	38.0	39.1	36.3	37.3
170311016	Illinois	Cook	43.0	46.3	41.0	44.1
170312001	Illinois	Cook	37.7	40.6	35.6	38.2
170313103	Illinois	Cook	39.6	40.3	38.1	38.7
170313301	Illinois	Cook	40.2	43.3	38.2	41.0
170316005	Illinois	Cook	39.1	41.8	37.4	39.8
171190023	Illinois	Madison	37.3	38.1	39.4	40.2
171191007	Illinois	Madison	39.1	40.1	40.0	40.6
171192009	Illinois	Madison	34.9	35.9	37.2	38.2
171193007	Illinois	Madison	34.0	34.6	36.5	37.3
180190006	Indiana	Clark	37.5	39.4	38.1	40.2
180372001	Indiana	Dubois	35.3	36.9	36.5	38.0
180830004	Indiana	Knox	35.9	36.3	35.9	36.5
180890022	Indiana	Lake	38.9	44.0	37.3	42.1
180890026	Indiana	Lake	38.4	41.3	36.3	39.3
180970042	Indiana	Marion	34.2	35.3	36.3	37.2
180970043	Indiana	Marion	38.4	39.9	40.5	42.0
180970066	Indiana	Marion	38.3	39.6	40.3	41.8
180970078	Indiana	Marion	36.6	37.6	38.7	39.7
180970079	Indiana	Marion	35.6	36.7	37.2	38.3
180970081	Indiana	Marion	38.2	39.2	40.1	41.1
180970083	Indiana	Marion	36.6	37.0	39.0	39.3
181570008	Indiana	Tippecanoe	35.6	36.7	35.9	36.9
191630019	Iowa	Scott	37.1	37.1	36.8	36.8
210590005	Kentucky	Daviess	33.8	33.8	37.0	37.0
211110043	Kentucky	Jefferson	35.4	36.1	35.8	36.4
211110044	Kentucky	Jefferson	36.1	36.6	36.0	36.5
211110048	Kentucky	Jefferson	36.4	37.2	35.6	36.4
245100040	Maryland	Baltimore City	39.0	40.9	36.3	38.3
245100049	Maryland	Baltimore City	38.1	38.1	35.5	35.5
261150005	Michigan	Monroe	38.8	39.6	37.0	38.0
261250001	Michigan	Oakland	39.9	40.4	37.9	38.4
261470005	Michigan	St. Clair	39.6	40.6	38.4	39.4
261610008	Michigan	Washtenaw	39.4	40.8	38.1	39.8
261630015	Michigan	Wayne	40.1	40.6	38.5	39.1
261630016	Michigan	Wayne	42.9	45.4	40.6	43.0
261630019	Michigan	Wayne	40.9	41.4	38.6	39.1
261630033	Michigan	Wayne	43.8	44.2	42.1	42.6
261630036	Michigan	Wayne	37.1	37.9	36.3	36.9
290990012	Missouri	Jefferson	33.4	34.2	35.7	36.5
291831002	Missouri	Saint Charles	33.1	34.7	35.5	37.1
295100007	Missouri	St. Louis City	33.1	33.5	36.0	36.3
295100087	Missouri	St. Louis City	34.3	34.7	36.4	36.9
340171003	New Jersey	Hudson	39.0	40.5	35.7	36.1
340172002	New Jersey	Hudson	41.4	41.4	38.2	38.2
340390004	New Jersey	Union	40.4	41.4	36.7	37.2
360050080	New York	Bronx	38.8	40.2	35.9	36.2
360610056	New York	New York	39.7	40.6	37.1	38.0
360610128	New York	New York	39.4	41.8	36.2	38.0
390170003	Ohio	Butler	39.2	41.1	40.3	42.3
390170016	Ohio	Butler	37.1	37.7	37.5	37.8
390170017	Ohio	Butler	37.9	37.9	38.5	38.5
390171004	Ohio	Butler	37.1	38.1	37.8	38.6
390350038	Ohio	Cuyahoga	44.2	47.0	41.2	44.0
390350045	Ohio	Cuyahoga	38.5	41.5	36.0	39.0
390350060	Ohio	Cuyahoga	42.1	45.7	39.4	42.8
390350065	Ohio	Cuyahoga	38.6	41.0	36.5	38.9
390490024	Ohio	Franklin	38.5	39.7	36.6	37.6
390490025	Ohio	Franklin	38.4	39.1	36.1	36.4
390610006	Ohio	Hamilton	37.6	37.6	38.0	38.0
390610014	Ohio	Hamilton	38.2	39.4	37.5	38.5
390610040	Ohio	Hamilton	36.7	37.7	35.8	36.8
390610042	Ohio	Hamilton	37.3	38.2	37.2	38.0
390610043	Ohio	Hamilton	35.9	36.2	36.0	36.4
390617001	Ohio	Hamilton	38.8	39.6	37.7	38.1
390618001	Ohio	Hamilton	40.6	40.9	39.6	40.3
390811001	Ohio	Jefferson	41.9	45.5	36.5	39.9
391130032	Ohio	Montgomery	37.8	40.0	36.3	38.5

TABLE IV.C–9—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES ($\mu g/m^3$) AT PROJECTED NONATTAINMENT SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
391530017	Ohio	Summit	38.0	39.6	35.6	37.2
420030008	Pennsylvania	Allegheny	39.4	39.9	35.9	36.3
420030064	Pennsylvania	Allegheny	64.2	68.2	58.8	62.3
420030093	Pennsylvania	Allegheny	45.6	51.5	41.1	46.2
420030116	Pennsylvania	Allegheny	42.5	42.5	37.1	37.1
420031008	Pennsylvania	Allegheny	41.3	42.8	38.0	39.3
420031301	Pennsylvania	Allegheny	40.3	42.4	36.6	38.6
420070014	Pennsylvania	Beaver	43.4	44.6	37.7	39.1
420110011	Pennsylvania	Berks	37.7	39.1	35.8	37.0
420210011	Pennsylvania	Cambria	39.0	39.4	40.3	40.7
420430401	Pennsylvania	Dauphin	38.0	39.0	35.7	37.1
420710007	Pennsylvania	Lancaster	40.8	44.0	37.7	40.1
421330008	Pennsylvania	York	38.2	40.7	35.9	38.8
471251009	Tennessee	Montgomery	36.3	37.5	36.6	37.9
540090011	West Virginia	Brooke	43.9	44.9	39.9	40.8
550790010	Wisconsin	Milwaukee	38.6	40.0	37.7	39.0
550790026	Wisconsin	Milwaukee	37.3	41.3	36.3	40.1
550790043	Wisconsin	Milwaukee	39.9	40.8	38.8	39.7
550790099	Wisconsin	Milwaukee	37.7	38.7	36.8	37.7

TABLE IV.C–10—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES ($\mu g/m^3$) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
110010041	Washington DC	Washington DC	36.3	37.8	34.0	35.6
110010042	Washington DC	Washington DC	34.9	37.0	33.0	35.6
170310022	Illinois	Cook	36.6	38.6	34.9	36.6
170310050	Illinois	Cook	36.1	38.0	34.1	35.8
170314007	Illinois	Cook	34.3	36.4	33.6	35.7
171630010	Illinois	Saint Clair	33.7	34.1	35.3	35.9
171971002	Illinois	Will	36.4	37.1	35.1	35.8
180390003	Indiana	Elkhart	34.4	36.3	33.8	35.6
180431004	Indiana	Floyd	33.2	34.5	34.3	35.7
181670023	Indiana	Vigo	34.8	36.1	35.1	36.5
191390015	Iowa	Muscatine	36.0	37.7	34.5	36.0
210290006	Kentucky	Bullitt	34.6	35.8	35.0	36.3
211451004	Kentucky	McCracken	33.6	35.9	34.4	36.8
212270007	Kentucky	Warren	33.1	35.1	33.7	36.3
240031003	Maryland	Anne Arundel	35.5	37.4	33.8	36.7
245100035	Maryland	Baltimore (City)	37.7	39.2	34.7	35.5
261630001	Michigan	Wayne	37.8	40.1	35.4	37.8
295100085	Missouri	St. Louis City	33.2	33.8	35.3	35.7
360610062	New York	New York	38.8	41.6	35.3	37.0
360610079	New York	New York	37.9	40.2	34.2	36.4
390350027	Ohio	Cuyahoga	36.6	38.8	34.5	36.6
390350034	Ohio	Cuyahoga	36.5	37.9	33.7	35.7
390810017	Ohio	Jefferson	40.7	42.4	35.3	36.8
390950024	Ohio	Lucas	36.3	38.6	34.2	36.5
390950026	Ohio	Lucas	34.9	36.7	33.6	35.6
390990014	Ohio	Mahoning	36.8	38.2	34.2	35.8
391130031	Ohio	Montgomery	35.7	37.1	34.3	35.6
391351001	Ohio	Preble	32.8	33.9	34.3	35.5
391550007	Ohio	Trumbull	36.2	37.8	33.9	35.6
420030095	Pennsylvania	Allegheny	38.7	40.7	34.3	36.6
420033007	Pennsylvania	Allegheny	37.5	43.1	33.8	38.5
420410101	Pennsylvania	Cumberland	38.0	40.2	35.3	37.0
421255001	Pennsylvania	Washington	38.1	39.9	33.9	35.5
471650007	Tennessee	Sumner	33.6	34.5	35.1	36.0
540090005	West Virginia	Brooke	39.4	41.5	33.9	36.1
550250047	Wisconsin	Dane	35.5	36.9	35.1	36.1
550790059	Wisconsin	Milwaukee	35.5	37.0	34.8	36.3
551330027	Wisconsin	Waukesha	35.4	36.2	34.9	35.6

(3) Methodology for Projecting Future 8-Hour Ozone Nonattainment and Maintenance

The following is a brief summary of the future year 8-hour average ozone calculations. Additional details are provided in the modeling guidance, MATS documentation, and the AQMTSD.

We are using the base period 2003–2007 ambient ozone design value data for projecting future year design values. The ozone projection procedure is relatively simple, since ozone is a single species. It is not necessary to interpolate ambient ozone data, since ambient ozone design values and gridded, modeled ozone is all that is needed for the projections.

To project 8-hour ozone design values we used the 2005 base year and 2012 future base case model-predicted ozone concentrations to calculate relative response factors. The methodology we followed is consistent with the attainment demonstration modeling guidance. The RRFs were applied to the 2003–2007 ozone design values through the following steps:

Step 1: For each monitoring site we calculate the average concentration across all days with 8-hour daily maximum predictions greater than or equal to 85 ppb [46] using the predictions in the nine grid cells that include or surround the location of the monitoring site. The RRF for a site is the ratio of the mean prediction in the future year to the mean prediction in the 2005 base year. The RRFs were calculated on a site-by-site basis.

Step 2: The RRF for each site is then multiplied by the 2003–2007 5-year weighted average ambient design value for that site, yielding an estimate of the future year design value at that particular monitoring location.

Step 3: We calculate the maximum future design value by projecting design values for each of the three base periods (2003–2005, 2004–2006, and 2005–2007) separately. The highest of the three future values is the maximum design value. This maximum value is used to identify the 8-hour ozone maintenance receptors.

The preceding procedures for determining future year 8-hour average ozone design values were applied for each ozone monitoring site. The future year design values are truncated to integers in units of ppb. This approach is consistent with the truncation and rounding procedures for the 8-hour ozone NAAQS. Future year design values that are greater than or equal to 85 ppb are considered to be violating the NAAQS. Sites with future year 5-year weighted average design values of 85 ppb or greater are predicted to be nonattainment. Sites with future year maximum design values of 85 ppb or greater are predicted to be future year maintenance sites. Note that, as described previously for the annual and 24-hour $PM_{2.5}$ NAAQS, nonattainment sites for the ozone NAAQS are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. For ease of reference we use the term "nonattainment sites" to refer to those sites that are projected to exceed the NAAQS based on both the average and maximum design values. Those sites that are projected to be attainment based on the average design value but exceed the NAAQS based on the maximum design value are referred to as maintenance sites. The monitoring sites that we project to be nonattainment and/or maintenance for the ozone NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of ozone NAAQS as part of this proposal.

Table IV.C–11 contains the 2003–2007 base period average and maximum 8-hour ozone design values and the 2012 base case average and maximum design values for sites projected to be 2012 nonattainment of the 8-hour ozone NAAQS in 2012. Table IV.C–12 contains this same information for projected 2012 8-hour ozone maintenance sites.

TABLE IV.C–11—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
220330003	Louisiana	East Baton Rouge	92	96	87.8	91.6
361030002	New York	Suffolk	90	91	86.3	87.2
361030009	New York	Suffolk	90.3	91	85.1	85.8
421010024	Pennsylvania	Philadelphia	90.3	91	85.3	86
480391004	Texas	Brazoria	94.7	97	88.8	91
482010051	Texas	Harris	93	98	88.4	93.1
482010055	Texas	Harris	100.7	103	95.7	97.9
482010062	Texas	Harris	95.7	99	90.5	93.7
482010066	Texas	Harris	92.3	96	89.9	93.5
482011039	Texas	Harris	96.3	100	90.5	93.9
484391002	Texas	Tarrant	93.3	95	85.1	86.7

TABLE IV.C–12—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
90010017	Connecticut	Fairfield	88	90	83.1	85
90011123	Connecticut	Fairfield	92.3	94	84.8	86.4
90013007	Connecticut	Fairfield	90	92	84.5	86.4

[46] As specified in the attainment demonstration modeling guidance, if there are less than 10 modeled days > 85 ppb, then the threshold is lowered in 1 ppb increments (to as low as 70 ppb) until there are 10 days. If there are less than 5 days > 70 ppb, then an RRF calculation is not completed for that site.

TABLE IV.C–12—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED MAINTENANCE-ONLY SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
90093002	Connecticut	New Haven	90.3	93	82.9	85.4
130890002	Georgia	DeKalb	88.7	93	81.6	85.6
131210055	Georgia	Fulton	91.7	94	84.4	86.5
361192004	New York	Westchester	87.7	90	84.7	86.9
420170012	Pennsylvania	Bucks	88	92	81.8	85.6
481130069	Texas	Dallas	87	90	82.9	85.8
481130087	Texas	Dallas	87	88	84.6	85.6
482010024	Texas	Harris	88	92	83.3	87.1
482010029	Texas	Harris	91.7	93	84.4	85.6
482011015	Texas	Harris	89	96	83.7	90.3
482011035	Texas	Harris	86.3	95	82	90.3
482011050	Texas	Harris	89.3	92	83.9	86.5
484392003	Texas	Tarrant	93.7	95	84	85.2

3. How did EPA assess interstate contributions to nonattainment and maintenance?

This section documents the procedures used by EPA to quantify the impact of emissions in specific upwind states on air quality concentrations in projected downwind nonattainment and maintenance locations for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone. These procedures are the first of the two-step approach for determining significant contribution, as described previously in section IV.A.3.

EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on projected downwind nonattainment and maintenance receptors for both $PM_{2.5}$ and 8-hour ozone. Details of the modeling techniques and post-processing procedures are described in this section.

CAMx employs enhanced source apportionment techniques which track the formation and transport of ozone and particulate matter from specific emissions sources and calculates the contribution of sources and precursors to ozone and $PM_{2.5}$ for individual receptor locations. The strength of the photochemical model source apportionment technique is that all modeled ozone and/or $PM_{2.5}$ mass at a given receptor location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources. This type of emissions apportionment is useful to understand the types of sources or regions that are contributing to ozone and $PM_{2.5}$ estimated by the model.

Source apportionment is an alternative approach to zero-out modeling[47] and other methods to track pollutant formation in photochemical models. Source apportionment completely characterizes source contributions to model-estimated ozone and $PM_{2.5}$, which is not possible with an emissions sensitivity approach such as zero-out, since the change in emissions leads to changes in pollutant concentrations, meaning the sum of estimated ozone or $PM_{2.5}$ in all zero-out simulations may not exactly match the ozone or $PM_{2.5}$ estimated in the base model simulation. Photochemical model source apportionment has the additional advantage over emissions sensitivity-based approaches of being more computationally efficient. There is currently no technical evidence showing that one technique is clearly superior to the other for evaluating contributions to ozone and $PM_{2.5}$ from various emission sources. However, since source apportionment explicitly tracks the formation and transport of all ozone and $PM_{2.5}$ mass, it is particularly well suited for quantifying interstate contributions as part of this proposal. More details on the implementation of photochemical source apportionment in CAMx can be found in the CAMx user's guide. In the analysis performed for CAIR, EPA conducted zero-out modeling for $PM_{2.5}$, and both zero-out and source apportionment modeling for ozone. The CAIR modeling was conducted at 36 km resolution for $PM_{2.5}$ and 12 km resolution for ozone. In contrast, the analysis for the Transport Rule was performed at 12 km resolution for both ozone and $PM_{2.5}$. When choosing the modeling techniques to use for the Transport Rule, we carefully considered all of the pros and cons of each technique, including the lengthy model run times and large file sizes of the 12 km eastern U.S. modeling domain. Due to the scientific credibility of the source apportionment technique and significant time and resource savings compared to zero-out modeling, we chose to perform the modeled contribution analyses for $PM_{2.5}$ and ozone with photochemical source apportionment.

The EPA performed source apportionment modeling for both ozone and $PM_{2.5}$ for the 2012 base case emissions. In this modeling we tracked the ozone and $PM_{2.5}$ formed from emissions from sources in each upwind state in the 12 km modeling domain. The results were used to calculate the contributions of these upwind emissions to downwind nonattainment and maintenance receptors. The states EPA analyzed using source apportionment for ozone and for $PM_{2.5}$ are: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, Washington DC, and Wisconsin. There were also several other states that are only partially contained within the 12 km modeling domain (*i.e.*, Colorado, Montana, New Mexico, and Wyoming). However, EPA did not individually track the emissions

[47] Zero-out modeling is a technique in which all emissions are removed (*e.g.,* NO_X and VOC emissions from a particular state) in a model run and then compared to the results of a second model run in which the same emissions have not been removed. The difference between the two model runs represents sensitivity or contribution from the emissions that were removed.

or assess the contribution from emissions in these states.

In contrast to CAIR, all contributions to downwind nonattainment and maintenance receptors for the Transport Rule were calculated using a relative approach. This is similar to the approach used to calculate future year design values, as described in section IV.C.2.a. In CAIR we used absolute and relative metrics to examine air quality contributions. Although absolute contributions are useful for certain applications, there are advantages of examining the relative contributions for both ozone and $PM_{2.5}$. The main advantage of relative contributions is that they help to minimize biases introduced by model over-predictions and under-predictions. Also, the relative approach constrains the total contributions to the measurements of ozone and $PM_{2.5}$ species concentrations at each downwind receptor. Since model performance is variable across the domain, EPA judged the relative approach to be the most appropriate technique for the Transport Rule.

a. Annual and 24-Hour $PM_{2.5}$ Contribution Modeling Approach

EPA used the CAMx Particulate Source Apportionment Technique (PSAT) to calculate downwind $PM_{2.5}$ contributions to nonattainment and maintenance. The CAMx PSAT is capable of "tagging" (*i.e.*, tracking) source category emissions for certain PM species and precursor emissions. For this proposal, we ran PSAT to tag emissions of NO_X, SO_2, and primary $PM_{2.5}$ from the individual states listed previously. Due to small modeled concentrations of secondary organic aerosols (SOA), and the relatively large runtime penalty of the SOA PSAT mechanism, we chose not to track SOA. Through emissions pre-processing procedures, EPA tagged all of the anthropogenic NO_X, SO_2, and primary $PM_{2.5}$ emissions in each upwind state. Each state was a separate tag, and the tagged emissions followed state boundaries (not grid cells).

In the PSAT simulation NO_X emissions are tracked to particulate nitrate concentrations, SO_2 emissions are tracked to particulate sulfate concentrations, and primary particulates (organic carbon, elemental carbon, and other $PM_{2.5}$) are tracked as primary particulates. As described earlier in section IV.B., the nitrate and sulfate contributions were combined and used to evaluate interstate contributions of $PM_{2.5}$, as described in section IV.C.4, later.

We developed and applied several post-processing steps to transform the PSAT modeling outputs to $PM_{2.5}$ downwind contributions. The approach involved processing the PSAT model outputs using MATS along with other post-processing software to calculate the contribution of each upwind state to each downwind nonattainment and/or maintenance receptor. This process involved calculating a ratio which uses the PSAT-predicted absolute contribution for each species (*e.g.*, sulfate) coupled with the CAMx-predicted absolute 2012 base case concentration of the same species. The PSAT-derived ratios were then multiplied by the corresponding species component concentrations comprising the 2012 base case $PM_{2.5}$ design value. For calculating annual contributions, we included the PSAT data for each day of the modeled year. For 24-hour calculations, the contributions are based on the 10 percent highest of the days in each quarter, as predicted for each receptor in the 2012 base case. In the 24-hour calculations, only the upwind contribution to the highest quarter at each receptor was used (*i.e.*, highest quarter based on 2012 $PM_{2.5}$ mass). For both annual and 24-hour $PM_{2.5}$, the total $PM_{2.5}$ mass contribution was calculated by summing the contributions of sulfate, nitrate, ammonium, and particle bound water.[48] Details on the procedures for calculating the contribution metrics are provided in the AQMTSD.

b. 8-Hour Ozone Contribution Modeling Approach

EPA used the CAM_X Ozone Source Apportionment Technique (OSAT) in order to calculate downwind 8-hour ozone contributions to nonattainment and maintenance. OSAT tracks the formation of ozone from NO_X and VOC emissions. Through emissions pre-processing procedures, EPA tagged all of the NO_X and VOC emissions in each upwind state. A separate tag was created for each state, and the tagged emissions followed state boundaries (not grid cells).

All anthropogenic sources of NO_X and VOC were tracked in the OSAT simulation. Upwind NO_X and VOC emissions were tracked to downwind ozone concentrations. There are several post-processing steps needed to transform the raw model outputs to ozone downwind contributions. We developed and applied several post-processing steps to transform the OSAT modeling outputs to ozone contributions at downwind receptors. The approach for ozone was similar to the approach for $PM_{2.5}$ in that the OSAT model outputs were processed using MATS along with other post-processing software to calculate the contribution of each upwind state to each downwind nonattainment and/or maintenance receptor. This process involved calculating a ratio which uses the OSAT-predicted absolute contribution of ozone coupled with the CAMx-predicted absolute 2012 base case ozone concentration. The OSAT-derived ratios were then multiplied by the corresponding 2012 base case ozone design value. The contributions to each downwind receptor are averaged across all days with modeled 2012 base case concentrations greater than 85 ppb[49] (at the given receptor). Details on the procedures for calculating the contribution metrics are provided in the AQMTSD.

c. Use of Projected Nonattainment and Maintenance Contributions

The previous steps provide the details for calculating 8-hour ozone and annual and 24-hour $PM_{2.5}$ contributions to all downwind receptors. After the post-processing of the model results is complete, we then evaluate the contributions of each upwind state to nonattainment and maintenance receptors. The nonattainment receptors are those monitoring sites which are projected to exceed the NAAQS in the 2012 base case, based on 5-year weighted average design values. The maintenance receptors are those monitoring sites which are projected to exceed the NAAQS in the 2012 base case based on the highest design value period. The upwind ozone and $PM_{2.5}$ contributions from each state are calculated for each downwind receptor. Contributions to nonattainment and maintenance receptors are evaluated independently for each state to determine if they are above the 1 percent threshold criteria.

For each upwind state, the maximum contribution to nonattainment is calculated based on the single largest

[48] The water and ammonium contributions are calculated by MATS using the default assumptions that were used to calculate future year 2012 $PM_{2.5}$ concentrations. The ammonium contribution is calculated assuming that all particulate nitrate is in the form of ammonium nitrate and the ammonium associated with sulfate is based on the degree of neutralization of the base year ambient data. In this way, the ammonium contribution is attributed to sulfate and nitrate precursors, not ammonia emissions. The water concentration is calculated based on an empirical formula that uses sulfate, nitrate, and ammonium concentrations.

[49] Ozone contributions are averaged over a minimum of 5 days. If there are fewer than 5 days greater than 85 ppb at a receptor, then the 85 ppb criterion is lowered in 1 ppb increments until there are 5 days of data for use in the calculations. If there are fewer than 5 modeled days greater than 70 ppb at the receptor, then the receptor is not used in the contribution calculations.

contribution to a future year (2012) downwind nonattainment receptor. The maximum contribution to maintenance is calculated based on the single largest contribution to a future year (2012) downwind maintenance receptor. Since the contributions are calculated independently for each receptor, the upwind contribution to maintenance can sometimes be larger than the contribution to nonattainment, and vice versa. This also means that maximum contributions to nonattainment can be below the threshold while maximum contributions to maintenance may be at or above the threshold, or vice versa.

4. What are the estimated interstate contributions to annual $PM_{2.5}$, 24-Hour $PM_{2.5}$, and 8-Hour ozone nonattainment and maintenance?

a. Contributions to Annual and 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

In this section, we present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the annual $PM_{2.5}$ NAAQS. We also present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the 24-hour $PM_{2.5}$ NAAQS. As described previously in section IV.B., states which contribute 0.15 $\mu g/m^3$or more to annual $PM_{2.5}$ nonattainment or maintenance in another state are identified as states with contributions to downwind attainment and maintenance sites large enough to warrant further analysis. For 24-hour $PM_{2.5}$, states which contribute 0.35 $\mu g/m^3$ or more to 24-hour $PM_{2.5}$ nonattainment or maintenance in another state are identified as states with contributions to downwind attainment and maintenance sites large enough to warrant further analysis. As described previously in section IV.C.3, we performed air quality modeling to quantify the contributions to annual and 24-hour $PM_{2.5}$ from emissions in each of the following 37 states individually: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland combined with the District of Columbia, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.

For annual $PM_{2.5}$, we calculated each state's contribution to each of the 32 monitoring sites that are projected to be nonattainment and each of the 16 sites that are projected to have maintenance problems for the annual $PM_{2.5}$ NAAQS in the 2012 base case. The largest contribution from each state to annual $PM_{2.5}$ nonattainment in downwind sites is provided in Table IV.C–13. The largest contribution from each state to annual $PM_{2.5}$ maintenance in downwind sites is also provided in Table IV.C–13. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the annual $PM_{2.5}$ NAAQS are provided in the AQMTSD.

TABLE IV.C–13—LARGEST CONTRIBUTION TO DOWNWIND ANNUAL $PM_{2.5}$ ($\mu G/M^3$) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind state	Largest downwind contribution to nonattainment for annual $PM_{2.5}$ ($\mu g/m^3$)	Largest downwind contribution to maintenance for annual $PM_{2.5}$ ($\mu g/m^3$)
Alabama	0.46	0.18
Arkansas	0.09	0.04
Connecticut	0.04	0.09
Delaware	0.20	0.14
Florida	0.29	0.07
Georgia	0.63	0.18
Illinois	1.01	0.63
Indiana	2.09	1.78
Iowa	0.31	0.30
Kansas	0.09	0.05
Kentucky	1.68	1.01
Louisiana	0.11	0.34
Maine	0.01	0.02
Maryland/Washington, D.C.	0.63	0.56
Massachusetts	0.07	0.13
Michigan	0.72	0.71
Minnesota	0.19	0.17
Mississippi	0.07	0.03
Missouri	1.38	0.27
Nebraska	0.08	0.06
New Hampshire	0.01	0.02
New Jersey	0.34	0.68
New York	0.49	0.47
North Carolina	0.19	0.11
North Dakota	0.05	0.05
Ohio	1.49	2.03
Oklahoma	0.08	0.05
Pennsylvania	0.83	1.60
Rhode Island	0.01	0.01
South Carolina	0.26	0.04
South Dakota	0.02	0.02
Tennessee	0.68	0.64
Texas	0.13	0.06
Vermont	0.00	0.00
Virginia	0.36	0.37

TABLE IV.C–13—LARGEST CONTRIBUTION TO DOWNWIND ANNUAL $PM_{2.5}$ (μG/M³) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES—Continued

Upwind state	Largest downwind contribution to nonattainment for annual $PM_{2.5}$ (μg/m³)	Largest downwind contribution to maintenance for annual $PM_{2.5}$ (μg/m³)
West Virginia	0.98	1.17
Wisconsin	0.46	0.42

Based on the state-by-state contribution analysis, there are 22 states and the District of Columbia [50] which contribute 0.15 μg/m³ or more to downwind annual $PM_{2.5}$ nonattainment. These states are: Alabama, Delaware, the District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–14, we provide a list of the downwind nonattainment sites to which each upwind state contributes 0.15 μg/m³ or more (i.e., the upwind state to downwind nonattainment "linkages").

There are 19 states and the District of Columbia [51] which contribute 0.15 μg/m³ or more to downwind annual $PM_{2.5}$ maintenance. These states are: Alabama, the District of Columbia, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–15, we provide a list of the downwind maintenance sites to which each upwind state contributes 0.15 μg/m³ or more (i.e., the upwind state to downwind maintenance "linkages").

[50] EPA combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland.

[51] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland.

TABLE IV.C–14—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)						
Alabama	6	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Clark, IN (180190006)	Dubois, IN (180372001)	Jefferson, KY (211110043)	
Delaware	2	Lancaster, PA (420710007)	York, PA (421330008)					
Florida	3	Jefferson, AL (10730023)	Bibb, GA (130210007)	Clayton, GA (130630091)				
Georgia	7	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Clark, IN (180190006)	Dubois, IN (180372001)	Jefferson, KY (211110043)	Kanawha, WV (540391005)	Cabell, WV (540110006)
Illinois	29	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Fulton, GA (131210039)	Bibb, GA (130210007)	Clayton, GA (130630091)	Clark, IN (180190006)	Dubois, IN (180372001)
		Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Jefferson, KY (211110043)	Wayne, MI (261630015)	Wayne, MI (261630033)	Butler, OH (390170016)
		Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)
		Kanawha, WV (540391005)						
Indiana	27	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Cook, IL (170310052)	Madison, IL (171191007)
		Saint Clair, IL (171630010)	Jefferson, KY (211110043)	Wayne, MI (261630015)	Wayne, MI (261630033)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)
		Cuyahoga, OH (390350060)	Hamilton, OH (390618001)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Allegheny, PA (420030064)
		Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)	
Iowa	4	Cook, IL (170310052)	Madison, IL (171191007)	Saint Clair, IL (171630010)	Dubois, IN (180372001)			
Kentucky	31	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Cook, IL (170310052)	Madison, IL (171191007)
		Saint Clair, IL (171630010)	Clark, IN (180190006)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Wayne, MI (261630015)
		Wayne, MI (261630033)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)
		Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)
		York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)				
Maryland	2	Lancaster, PA (420710007)	York, PA (421330008)					
Michigan	25	Cook, IL (170310052)	Madison, IL (171191007)	Saint Clair, IL (171630010)	Clark, IN (180190006)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)
		Marion, IN (180970083)	Jefferson, KY (211110043)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)
		Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)
		Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)			
Minnesota	1	Cook, IL (170310052)						
Missouri	17	Cook, IL (170310052)	Madison, IL (171191007)	Saint Clair, IL (171630010)	Clark, IN (180190006)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)
		Marion, IN (180970083)	Jefferson, KY (211110043)	Butler, OH (390170016)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Cabell, WV (540110006)	Kanawha, WV (540391005)				
New Jersey	2	Lancaster, PA (420710007)	York, PA (421330008)					

TABLE IV.C–14—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$—Continued

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)						
New York	8	Cuyahoga, OH (390350038) York, PA (421330008)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)
North Carolina	3	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)				
Ohio	23	Jefferson, AL (10730023) Saint Clair, IL (171630010) Wayne, MI (261630015) Cabell, WV (540110006)	Jefferson, AL (10732003) Clark, IN (180190006) Wayne, MI (261630033) Kanawha, WV (540391005)	Bibb, GA (130210007) Dubois, IN (180372001) Allegheny, PA (420030064)	Clayton, GA (130630091) Marion, IN (180970078) Allegheny, PA (420031301)	Fulton, GA (131210039) Marion, IN (180970081) Beaver, PA (420070014)	Cook, IL (170310052) Marion, IN (180970083) Lancaster, PA (420710007)	Madison, IL (171191007) Jefferson, KY (211110043) York, PA (421330008)
Pennsylvania	25	Bibb, GA (130210007) Dubois, IN (180372001) Butler, OH (390170016) Hamilton, OH (390617001)	Clayton, GA (130630091) Marion, IN (180970078) Cuyahoga, OH (390350038) Hamilton, OH (390618001)	Fulton, GA (131210039) Marion, IN (180970081) Cuyahoga, OH (390350045) Cabell, WV (540110006)	Cook, IL (170310052) Marion, IN (180970083) Cuyahoga, OH (390350060) Kanawha, WV (540391005)	Madison, IL (171191007) Jefferson, KY (211110043) Hamilton, OH (390610014)	Saint Clair, IL (171630010) Wayne, MI (261630015) Hamilton, OH (390610042)	Clark, IN (180190006) Wayne, MI (261630033) Hamilton, OH (390610043)
South Carolina	3	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)				
Tennessee	29	Jefferson, AL (10730023) Saint Clair, IL (171630010) Wayne, MI (261630033) Hamilton, OH (390610043) Kanawha, WV (540391005)	Jefferson, AL (10732003) Dubois, IN (180372001) Butler, OH (390170016) Hamilton, OH (390617001)	Bibb, GA (130210007) Marion, IN (180970078) Cuyahoga, OH (390350038) Hamilton, OH (390618001)	Clayton, GA (130630091) Marion, IN (180970081) Cuyahoga, OH (390350045) Allegheny, PA (420030064)	Fulton, GA (131210039) Marion, IN (180970083) Cuyahoga, OH (390350060) Allegheny, PA (420031301)	Clark, IN (180190006) Jefferson, KY (211110043) Hamilton, OH (390610014) Beaver, PA (420070014)	Madison, IL (171191007) Wayne, MI (261630015) Hamilton, OH (390610042) Cabell, WV (540110006)
Virginia	4	Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)			
West Virginia	25	Fulton, GA (131210039) Dubois, IN (180372001) Cuyahoga, OH (390350060) Allegheny, PA (420031301)	Bibb, GA (130210007) Jefferson, KY (211110043) Hamilton, OH (390610014) Beaver, PA (420070014)	Clayton, GA (130630091) Wayne, MI (261630015) Hamilton, OH (390610042) Lancaster, PA (420710007)	Clark, IN (180190006) Wayne, MI (261630033) Hamilton, OH (390610043) York, PA (421330008)	Marion, IN (180970078) Butler, OH (390170016) Hamilton, OH (390617001)	Marion, IN (180970081) Cuyahoga, OH (390350038) Hamilton, OH (390618001)	Marion, IN (180970083) Cuyahoga, OH (390350045) Allegheny, PA (420030064)
Wisconsin	8	Cook, IL (170310052) Cuyahoga, OH (390350045)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Wayne, MI (261630015)	Wayne, MI (261630033)

TABLE IV.C–15—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)						
Alabama	1	Jefferson, KY (211110044)						
Georgia	1	Jefferson, KY (211110044)						
Illinois	13	Jefferson, KY (211110044) Berks, PA (420110011)	Cuyahoga, OH (390350027) Harris, TX (482011035)	Cuyahoga, OH (390350065) Berkeley, WV (540030003)	Hamilton, OH (390610040) Brooke, WV (540090005)	Jefferson, OH (390811001) Hancock, WV (540291004)	Montgomery, OH (391130032) Marion, WV (540490006)	Stark, OH (391510017)
Indiana	16	Cook, IL (170313301) Jefferson, OH (390811001) Hancock, WV (540291004)	Cook, IL (170316005) Montgomery, OH (391130032) Marion, WV (540490006)	Jefferson, KY (211110044) Stark, OH (391510017)	New York, NY (360610056) Berks, PA (420110011)	Cuyahoga, OH (390350027) Harris, TX (482011035)	Cuyahoga, OH (390350065) Berkeley, WV (540030003)	Hamilton, OH (390610040) Brooke, WV (540090005)
Iowa	2	Cook, IL (170313301)	Cook, IL (170316005)					
Kentucky	12	Cook, IL (170313301) Stark, OH (391510017)	Cook, IL (170316005) Berkeley, WV (540030003)	Cuyahoga, OH (390350027) Brooke, WV (540090005)	Cuyahoga, OH (390350065) Hancock, WV (540291004)	Hamilton, OH (390610040) Marion, WV (540490006)	Jefferson, OH (390811001)	Montgomery, OH (391130032)
Louisiana	1	Harris, TX (482011035)						
Maryland	2	Berks, PA (420110011)	Berkeley, WV (540030003)					
Michigan	15	Cook, IL (170313301) Jefferson, OH (390811001) Marion, WV (540490006)	Cook, IL (170316005) Montgomery, OH (391130032)	Jefferson, KY (211110044) Stark, OH (391510017)	New York, NY (360610056) Berks, PA (420110011)	Cuyahoga, OH (390350027) Berkeley, WV (540030003)	Cuyahoga, OH (390350065) Brooke, WV (540090005)	Hamilton, OH (390610040) Hancock, WV (540291004)
Minnesota	1	Cook, IL (170316005)						
Missouri	6	Cook, IL (170313301)	Cook, IL (170316005)	Jefferson, KY (211110044)	Hamilton, OH (390610040)	Montgomery, OH (391130032)	Stark, OH (391510017)	
New Jersey	2	New York, NY (360610056)	Berks, PA (420110011)					
New York	9	Cuyahoga, OH (390350027) Hancock, WV (540291004)	Cuyahoga, OH (390350065) Marion, WV (540490006)	Jefferson, OH (390811001)	Stark, OH (391510017)	Berks, PA (420110011)	Berkeley, WV (540030003)	Brooke, WV (540090005)
Ohio	9	Cook, IL (170313301) Hancock, WV (540291004)	Cook, IL (170316005) Marion, WV (540490006)	Jefferson, KY (211110044)	New York, NY (360610056)	Berks, PA (420110011)	Berkeley, WV (540030003)	Brooke, WV (540090005)
Pennsylvania	14	Cook, IL (170313301) Jefferson, OH (390811001)	Cook, IL (170316005) Montgomery, OH (391130032)	Jefferson, KY (211110044) Stark, OH (391510017)	New York, NY (360610056) Berkeley, WV (540030003)	Cuyahoga, OH (390350027) Brooke, WV (540090005)	Cuyahoga, OH (390350065) Hancock, WV (540291004)	Hamilton, OH (390610040) Marion, WV (540490006)
Tennessee	10	Jefferson, KY (211110044) Brooke, WV (540090005)	Cuyahoga, OH (390350027) Hancock, WV (540291004)	Cuyahoga, OH (390350065) Marion, WV (540490006)	Hamilton, OH (390610040)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Stark, OH (391510017)
Virginia	4	New York, NY (360610056)	Berks, PA (420110011)	Berkeley, WV (540030003)	Marion, WV (540490006)			
West Virginia	9	Jefferson, KY (211110044) Stark, OH (391510017)	New York, NY (360610056) Berks, PA (420110011)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)	Jefferson, OH (390811001)	Montgomery, OH (391130032)

TABLE IV.C–15—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Wisconsin	2	Cook, IL (170313301)	Cook, IL (170316005)				

For 24-hour $PM_{2.5}$, we calculated each state's contribution to each of the 92 monitoring sites that are projected to be nonattainment and each of the 38 sites that are projected to have maintenance problems for the 24-hour $PM_{2.5}$ NAAQS in the 2012 base case. The largest contribution from each state to 24-hour $PM_{2.5}$ nonattainment in downwind sites is provided in Table IV.C–16. The largest contribution from each state to 24-hour $PM_{2.5}$ maintenance in downwind sites is also provided in Table IV.C–16. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the 24-hour $PM_{2.5}$ NAAQS are provided in the AQMTSD.

TABLE IV.C–16—LARGEST CONTRIBUTION TO DOWNWIND 24-HOUR $PM_{2.5}$ ($\mu g/m^3$) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind State	Largest downwind contribution to nonattainment for 24-hour $PM_{2.5}$ ($\mu g/m^3$)	Largest downwind contribution to maintenance for 24-hour $PM_{2.5}$ ($\mu g/m^3$)
Alabama	0.48	0.32
Arkansas	0.20	0.17
Connecticut	0.41	0.70
Delaware	0.50	0.36
Florida	0.08	0.08
Georgia	0.95	0.41
Illinois	7.28	6.57
Indiana	9.91	8.94
Iowa	1.87	1.67
Kansas	0.77	0.45
Kentucky	6.53	6.91
Louisiana	0.23	0.18
Maine	0.19	0.19
Maryland/Washington, DC	2.63	1.82
Massachusetts	0.67	0.71
Michigan	2.35	3.35
Minnesota	0.91	0.86
Mississippi	0.09	0.04
Missouri	5.03	4.82
Nebraska	0.62	0.39
New Hampshire	0.21	0.23
New Jersey	2.69	4.74
New York	5.82	1.17
North Carolina	0.50	0.45
North Dakota	0.27	0.15
Ohio	5.84	5.56
Oklahoma	0.16	0.21
Pennsylvania	3.67	4.86
Rhode Island	0.05	0.06
South Carolina	0.19	0.19
South Dakota	0.13	0.09
Tennessee	3.92	4.70
Texas	0.21	0.28
Vermont	0.06	0.07
Virginia	1.32	2.26
West Virginia	3.51	4.83
Wisconsin	0.80	1.01

Based on the state-by-state contribution analysis, there are 24 states and the District of Columbia [52] which contribute 0.35 $\mu g/m^3$ or more to downwind 24-hour $PM_{2.5}$ nonattainment. These states are: Alabama, the District of Columbia, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–17, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.35 $\mu g/m^3$ or more (*i.e.*, the upwind state to downwind nonattainment "linkages").

There are 23 states and the District of Columbia which contribute 0.35 $\mu g/m^3$ or more to downwind 24-hour $PM_{2.5}$ maintenance. These states are: Connecticut, Delaware, the District of Columbia, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–18, we provide a list of the downwind maintenance sites to which each upwind state contributes 0.35 $\mu g/m^3$ or more (*i.e.*, the upwind state to downwind maintenance "linkages").

[52] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland.

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Alabama	5	Monroe, MI (261150005)	Wayne, MI (261630015)	Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390618001)	
Connecticut	3	Hudson, NJ (340172002)	New York, NY (360610056)	New York, NY (360610128)			
Delaware	2	Union, NJ (340390004)	Dauphin, PA (420430401)				
Georgia	12	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	Union, NJ (340390004)	Butler, OH (390170016)
		Butler, OH (390171004)	Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390618001)	Montgomery, OH (391130032)	York, PA (421330008)
Illinois	70	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)
		Lake, IN (180890022)	Lake, IN (180890026)	Marion, IN (180970042)	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)
		Marion, IN (180970079)	Marion, IN (180970081)	Marion, IN (180970083)	Tippecanoe, IN (181570008)	Scott, IA (191630019)	Daviess, KY (210590005)
		Jefferson, KY (211110043)	Jefferson, KY (211110044)	Jefferson, KY (211110048)	Monroe, MI (261150005)	Oakland, MI (261250001)	St. Clair, MI (261470005)
		Washtenaw, MI (261610008)	Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Wayne, MI (261630036)
		Jefferson, MO (290990012)	Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Union, NJ (340390004)	New York, NY (360610128)
		Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)	Butler, OH (390171004)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)
		Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)	Hamilton, OH (390610006)	Hamilton, OH (390610014)
		Hamilton, OH (390610040)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Jefferson, OH (390811001)
		Montgomery, OH (391130032)	Summit, OH (391530017)	Allegheny, PA (420030064)	Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)
		Allegheny, PA (420031301)	Beaver, PA (420070014)	Berks, PA (420110011)	Cambria, PA (420210011)	Montgomery, TN (471251009)	Brooke, WV (540090011)
		Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)		
Indiana	75	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)
		Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)	Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)
		Madison, IL (171191007)	Madison, IL (171192009)	Madison, IL (171193007)	Scott, IA (191630019)	Daviess, KY (210590005)	Jefferson, KY (211110043)
		Jefferson, KY (211110044)	Jefferson, KY (211110048)	Monroe, MI (261150005)	Oakland, MI (261250001)	St. Clair, MI (261470005)	Washtenaw, MI (261610008)
		Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Wayne, MI (261630036)	Jefferson, MO (290990012)
		Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Hudson, NJ (340171003)	Union, NJ (340390004)	Bronx, NY (360050080)
		New York, NY (360610056)	New York, NY (360610128)	Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)	Butler, OH (390171004)
		Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)
		Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390610040)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Summit, OH (391530017)	Allegheny, PA (420030008)	Allegheny, PA (420030064)
		Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Berks, PA (420110011)
		Cambria, PA (420210011)	Dauphin, PA (420430401)	York, PA (421330008)	Montgomery, TN (471251009)	Brooke, WV (540090011)	Milwaukee, WI (550790010)
		Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)			
Iowa	17	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)	Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)
		Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171191007)	Lake, IN (180890022)	Lake, IN (180890026)	Jefferson, MO (290990012)
		St. Louis City, MO (295100007)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)	
Kansas	3	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790099)			
Kentucky	81	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)
		Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)	Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)
		Madison, IL (171191007)	Madison, IL (171192009)	Madison, IL (171193007)	Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)
		Lake, IN (180890026)	Marion, IN (180970042)	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)	Marion, IN (180970079)
		Marion, IN (180970081)	Marion, IN (180970083)	Tippecanoe, IN (181570008)	Scott, IA (191630019)	Monroe, MI (261150005)	Oakland, MI (261250001)

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		St. Clair, MI (261470005) Wayne, MI (261630036) Union, NJ (340390004) Butler, OH (390171004) Franklin, OH (390490025) Hamilton, OH (390617001) Allegheny, PA (420030064) Berks, PA (420110011) Milwaukee, WI (550790026)	Washtenaw, MI (261610008) Jefferson, MO (290990012) Bronx, NY (360050080) Cuyahoga, OH (390350038) Hamilton, OH (390610006) Hamilton, OH (390618001) Allegheny, PA (420030093) Cambria, PA (420210011) Milwaukee, WI (550790043)	Wayne, MI (261630015) Saint Charles, MO (291831002) New York, NY (360610128) Cuyahoga, OH (390350045) Hamilton, OH (390610014) Jefferson, OH (390811001) Allegheny, PA (420030116) York, PA (421330008) Milwaukee, WI (550790099)	Wayne, MI (261630016) St. Louis City, MO (295100007) Butler, OH (390170003) Cuyahoga, OH (390350060) Hamilton, OH (390610040) Montgomery, OH (391130032) Allegheny, PA (420031008) Montgomery, TN (471251009)	Wayne, MI (261630019) St. Louis City, MO (295100087) Butler, OH (390170016) Cuyahoga, OH (390350065) Hamilton, OH (390610042) Summit, OH (391530017) Allegheny, PA (420031301) Brooke, WV (540090011)	Wayne, MI (261630033) Hudson, NJ (340171003) Butler, OH (390170017) Franklin, OH (390490024) Hamilton, OH (390610043) Allegheny, PA (420030008) Beaver, PA (420070014) Milwaukee, WI (550790010)
Maryland	11	New Haven, CT (90091123) New York, NY (360610128)	Hudson, NJ (340171003) Berks, PA (420110011)	Hudson, NJ (340172002) Dauphin, PA (420430401)	Union, NJ (340390004) Lancaster, PA (420710007)	Bronx, NY (360050080) York, PA (421330008)	New York, NY (360610056)
Massachusetts	3	New Haven, CT (90091123)	New York, NY (360610056)	New York, NY (360610128)			
Michigan	48	Cook, IL (170310052) Cook, IL (170313301) Knox, IN (180830004) St. Louis City, MO (295100007) Cuyahoga, OH (390350065) Jefferson, OH (390811001) Allegheny, PA (420030116) Montgomery, TN (471251009) Milwaukee, WI (550790099)	Cook, IL (170310057) Cook, IL (170316005) Lake, IN (180890022) St. Louis City, MO (295100087) Franklin, OH (390490024) Montgomery, OH (391130032) Allegheny, PA (420031008) Brooke, WV (540090011)	Cook, IL (170310076) Madison, IL (171190023) Lake, IN (180890026) New York, NY (360610128) Franklin, OH (390490025) Summit, OH (391530017) Allegheny, PA (420031301) Milwaukee, WI (550790010)	Cook, IL (170311016) Madison, IL (171191007) Scott, IA (191630019) Cuyahoga, OH (390350038) Hamilton, OH (390610014) Allegheny, PA (420030008) Beaver, PA (420070014) Milwaukee, WI (550790026)	Cook, IL (170312001) Madison, IL (171192009) Jefferson, MO (290990012) Cuyahoga, OH (390350045) Hamilton, OH (390617001) Allegheny, PA (420030064) Cambria, PA (420210011) Milwaukee, WI (550790043)	Cook, IL (170313103) Madison, IL (171193007) Saint Charles, MO (291831002) Cuyahoga, OH (390350060) Hamilton, OH (390618001) Allegheny, PA (420030093) Dauphin, PA (420430401)
Minnesota	4	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)		
Missouri	56	Cook, IL (170310052) Cook, IL (170313301) Clark, IN (180190006) Marion, IN (180970043) Tippecanoe, IN (181570008) Monroe, MI (261150005) Butler, OH (390170003) Hamilton, OH (390610006) Hamilton, OH (390618001) Milwaukee, WI (550790043)	Cook, IL (170310057) Cook, IL (170316005) Dubois, IN (180372001) Marion, IN (180970066) Scott, IA (191630019) Oakland, MI (261250001) Butler, OH (390170016) Hamilton, OH (390610014) Montgomery, OH (391130032) Milwaukee, WI (550790099)	Cook, IL (170310076) Madison, IL (171190023) Knox, IN (180830004) Marion, IN (180970078) Daviess, KY (210590005) Washtenaw, MI (261610008) Butler, OH (390170017) Hamilton, OH (390610040) Allegheny, PA (420030116)	Cook, IL (170311016) Madison, IL (171191007) Lake, IN (180890022) Marion, IN (180970079) Jefferson, KY (211110043) Wayne, MI (261630015) Butler, OH (390171004) Hamilton, OH (390610042) Montgomery, TN (471251009)	Cook, IL (170312001) Madison, IL (171192009) Lake, IN (180890026) Marion, IN (180970081) Jefferson, KY (211110044) Wayne, MI (261630033) Franklin, OH (390490024) Hamilton, OH (390610043) Milwaukee, WI (550790010)	Cook, IL (170313103) Madison, IL (171193007) Marion, IN (180970042) Marion, IN (180970083) Jefferson, KY (211110048) Wayne, MI (261630036) Franklin, OH (390490025) Hamilton, OH (390617001) Milwaukee, WI (550790026)
Nebraska	3	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790099)			
New Jersey	9	New Haven, CT (90091123) Dauphin, PA (420430401)	Baltimore City, MD (245100049) Lancaster, PA (420710007)	Bronx, NY (360050080) York, PA (421330008)	New York, NY (360610056)	New York, NY (360610128)	Berks, PA (420110011)
New York	23	New Haven, CT (90091123) Wayne, MI (261630019) Cuyahoga, OH (390350038) Summit, OH (391530017)	Baltimore City, MD (245100040) Wayne, MI (261630033) Cuyahoga, OH (390350045) Berks, PA (420110011)	Baltimore City, MD (245100049) Wayne, MI (261630036) Cuyahoga, OH (390350060) Dauphin, PA (420430401)	St. Clair, MI (261470005) Hudson, NJ (340171003) Cuyahoga, OH (390350065) Lancaster, PA (420710007)	Washtenaw, MI (261610008) Hudson, NJ (340172002) Franklin, OH (390490024) York, PA (421330008)	Wayne, MI (261630016) Union, NJ (340390004) Franklin, OH (390490025)

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
North Carolina	11	Baltimore City, MD (245100040) New York, NY (360610056)	Baltimore City, MD (245100049) Berks, PA (420110011)	Hudson, NJ (340171003) Dauphin, PA (420430401)	Hudson, NJ (340172002) Lancaster, PA (420710007)	Union, NJ (340390004) York, PA (421330008)	Bronx, NY (360050080)
Ohio	72	Jefferson, AL (10730023) Cook, IL (170311016) Madison, IL (171191007) Lake, IN (180890022) Marion, IN (180970079) Jefferson, KY (211110043) Oakland, MI (261250001) Wayne, MI (261630033) Hudson, NJ (340171003) Allegheny, PA (420030008) Beaver, PA (420070014) Montgomery, TN (471251009)	Jefferson, AL (10732003) Cook, IL (170312001) Madison, IL (171192009) Lake, IN (180890026) Marion, IN (180970081) Jefferson, KY (211110044) St. Clair, MI (261470005) Wayne, MI (261630036) Hudson, NJ (340172002) Allegheny, PA (420030064) Berks, PA (420110011) Brooke, WV (540090011)	New Haven, CT (90091123) Cook, IL (170313103) Madison, IL (171193007) Marion, IN (180970042) Marion, IN (180970083) Jefferson, KY (211110048) Washtenaw, MI (261610008) Jefferson, MO (290990012) Union, NJ (340390004) Allegheny, PA (420030093) Cambria, PA (420210011) Milwaukee, WI (550790010)	Cook, IL (170310052) Cook, IL (170313301) Clark, IN (180190006) Marion, IN (180970043) Tippecanoe, IN (181570008) Baltimore City, MD (245100040) Wayne, MI (261630015) Saint Charles, MO (291831002) Bronx, NY (360050080) Allegheny, PA (420030116) Dauphin, PA (420430401) Milwaukee, WI (550790026)	Cook, IL (170310057) Cook, IL (170316005) Dubois, IN (180372001) Marion, IN (180970066) Scott, IA (191630019) Baltimore City, MD (245100049) Wayne, MI (261630016) St. Louis City, MO (295100007) New York, NY (360610056) Allegheny, PA (420031008) Lancaster, PA (420710007) Milwaukee, WI (550790043)	Cook, IL (170310076) Madison, IL (171190023) Knox, IN (180830004) Marion, IN (180970078) Daviess, KY (210590005) Monroe, MI (261150005) Wayne, MI (261630019) St. Louis City, MO (295100087) New York, NY (360610128) Allegheny, PA (420031301) York, PA (421330008) Milwaukee, WI (550790099)
Pennsylvania	77	Jefferson, AL (10730023) Cook, IL (170311016) Madison, IL (171192009) Lake, IN (180890026) Marion, IN (180970081) Jefferson, KY (211110048) Washtenaw, MI (261610008) Jefferson, MO (290990012) Union, NJ (340390004) Butler, OH (390170017) Franklin, OH (390490024) Hamilton, OH (390610043) Montgomery, TN (471251009)	Jefferson, AL (10732003) Cook, IL (170312001) Madison, IL (171193007) Marion, IN (180970042) Marion, IN (180970083) Baltimore City, MD (245100040) Wayne, MI (261630015) Saint Charles, MO (291831002) Bronx, NY (360050080) Butler, OH (390171004) Franklin, OH (390490025) Hamilton, OH (390617001) Brooke, WV (540090011)	New Haven, CT (90091123) Cook, IL (170313103) Madison, IL (171190023) Marion, IN (180970043) Tippecanoe, IN (181570008) Baltimore City, MD (245100049) Wayne, MI (261630016) St. Louis City, MO (295100007) New York, NY (360610056) Cuyahoga, OH (390350038) Hamilton, OH (390610006) Hamilton, OH (390618001) Milwaukee, WI (550790026)	Cook, IL (170310052) Cook, IL (170313301) Clark, IN (180190006) Marion, IN (180970066) Scott, IA (191630019) Monroe, MI (261150005) Wayne, MI (261630019) St. Louis City, MO (295100087) New York, NY (360610128) Cuyahoga, OH (390350045) Hamilton, OH (390610014) Jefferson, OH (390811001) Milwaukee, WI (550790043)	Cook, IL (170310057) Cook, IL (170316005) Dubois, IN (180372001) Marion, IN (180970078) Jefferson, KY (211110043) Oakland, MI (261250001) Wayne, MI (261630033) Hudson, NJ (340171003) Butler, OH (390170003) Cuyahoga, OH (390350060) Hamilton, OH (390610040) Montgomery, OH (391130032) Milwaukee, WI (550790099)	Cook, IL (170310076) Madison, IL (171191007) Knox, IN (180830004) Marion, IN (180970079) Jefferson, KY (211110044) St. Clair, MI (261470005) Wayne, MI (261630036) Hudson, NJ (340172002) Butler, OH (390170016) Cuyahoga, OH (390350065) Hamilton, OH (390610042) Summit, OH (391530017)
Tennessee	61	Jefferson, AL (10730023) Madison, IL (171193007) Marion, IN (180970066) Scott, IA (191630019) Oakland, MI (261250001) Jefferson, MO (290990012) Butler, OH (390170003) Cuyahoga, OH (390350065) Hamilton, OH (390610042) Summit, OH (391530017) York, PA (421330008)	Jefferson, AL (10732003) Clark, IN (180190006) Marion, IN (180970078) Daviess, KY (210590005) St. Clair, MI (261470005) Saint Charles, MO (291831002) Butler, OH (390170016) Franklin, OH (390490024) Hamilton, OH (390610043) Allegheny, PA (420030093)	New Haven, CT (90091123) Dubois, IN (180372001) Marion, IN (180970079) Jefferson, KY (211110043) Washtenaw, MI (261610008) St. Louis City, MO (295100007) Butler, OH (390170017) Franklin, OH (390490025) Hamilton, OH (390617001) Allegheny, PA (420030116)	Madison, IL (171190023) Knox, IN (180830004) Marion, IN (180970081) Jefferson, KY (211110044) Wayne, MI (261630015) St. Louis City, MO (295100087) Butler, OH (390171004) Hamilton, OH (390610006) Hamilton, OH (390618001) Allegheny, PA (420031008)	Madison, IL (171191007) Marion, IN (180970042) Marion, IN (180970083) Jefferson, KY (211110048) Wayne, MI (261630033) Union, NJ (340390004) Cuyahoga, OH (390350038) Hamilton, OH (390610014) Jefferson, OH (390811001) Allegheny, PA (420031301)	Madison, IL (171192009) Marion, IN (180970043) Tippecanoe, IN (181570008) Monroe, MI (261150005) Wayne, MI (261630036) New York, NY (360610128) Cuyahoga, OH (390350045) Hamilton, OH (390610040) Montgomery, OH (391130032) Cambria, PA (420210011)
Virginia	13	New Haven, CT (90091123)	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	Hudson, NJ (340171003)	Hudson, NJ (340172002)	Union, NJ (340390004)

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		Bronx, NY (360050080) York, PA (421330008)	New York, NY (360610056)	New York, NY (360610128)	Berks, PA (420110011)	Dauphin, PA (420430401)	Lancaster, PA (420710007)
West Virginia	84	Jefferson, AL (10730023) Cook, IL (170311016) Madison, IL (171192009) Marion, IN (180970043) Tippecanoe, IN (181570008) Baltimore City, MD (245100049) Wayne, MI (261630016) St. Louis City, MO (295100007) New York, NY (360610056) Cuyahoga, OH (390350038) Hamilton, OH (390610006) Hamilton, OH (390618001) Allegheny, PA (420030093) Cambria, PA (420210011)	Jefferson, AL (10732003) Cook, IL (170312001) Madison, IL (171193007) Marion, IN (180970066) Scott, IA (191630019) Monroe, MI (261150005) Wayne, MI (261630019) St. Louis City, MO (295100087) New York, NY (360610128) Cuyahoga, OH (390350045) Hamilton, OH (390610014) Jefferson, OH (390811001) Allegheny, PA (420030116) Dauphin, PA (420430401)	New Haven, CT (90091123) Cook, IL (170313301) Clark, IN (180190006) Marion, IN (180970078) Jefferson, KY (211110043) Oakland, MI (261250001) Wayne, MI (261630033) Hudson, NJ (340171003) Butler, OH (390170003) Cuyahoga, OH (390350060) Hamilton, OH (390610040) Montgomery, OH (391130032) Allegheny, PA (420031008) Lancaster, PA (420710007)	Cook, IL (170310052) Cook, IL (170316005) Dubois, IN (180372001) Marion, IN (180970079) Jefferson, KY (211110044) St. Clair, MI (261470005) Wayne, MI (261630036) Hudson, NJ (340172002) Butler, OH (390170016) Cuyahoga, OH (390350065) Hamilton, OH (390610042) Summit, OH (391530017) Allegheny, PA (420031301) York, PA (421330008)	Cook, IL (170310057) Madison, IL (171190023) Lake, IN (180890026) Marion, IN (180970081) Jefferson, KY (211110048) Washtenaw, MI (261610008) Jefferson, MO (290990012) Union, NJ (340390004) Butler, OH (390170017) Franklin, OH (390490024) Hamilton, OH (390610043) Allegheny, PA (420030008) Beaver, PA (420070014) Montgomery, TN (471251009)	Cook, IL (170310076) Madison, IL (171191007) Marion, IN (180970042) Marion, IN (180970083) Baltimore City, MD (245100040) Wayne, MI (261630015) Saint Charles, MO (291831002) Bronx, NY (360050080) Butler, OH (390171004) Franklin, OH (390490025) Hamilton, OH (390617001) Allegheny, PA (420030064) Berks, PA (420110011) Milwaukee, WI (550790043)
Wisconsin	12	Cook, IL (170310052) Cook, IL (170313301)	Cook, IL (170310057) Cook, IL (170316005)	Cook, IL (170310076) Lake, IN (180890022)	Cook, IL (170311016) Lake, IN (180890026)	Cook, IL (170312001) Scott, IA (191630019)	Cook, IL (170313103) Wayne, MI (261630016)

TABLE IV.C–18—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Connecticut	1	New York, NY (360610062)					
Delaware	2	Cumberland, PA (420410101)	New York, NY (360610079)				
Georgia	3	Baltimore City, MD (245100035)	Lucas, OH (390950026)	Preble, OH (391351001)			
Illinois	29	District of Columbia (110010041) Bullitt, KY (210290006) Cuyahoga, OH (390350027) Montgomery, OH (391130031) Sumner, TN (471650007)	District of Columbia (110010042) McCracken, KY (211451004) Cuyahoga, OH (390350034) Preble, OH (391351001) Brooke, WV (540090005)	Elkhart, IN (180390003) Warren, KY (212270007) Jefferson, OH (390810017) Trumbull, OH (391550007) Dane, WI (550250047)	Floyd, IN (180431004) Wayne, MI (261630001) Lucas, OH (390950024) Allegheny, PA (420030095) Milwaukee, WI (550790059)	Vigo, IN (181670023) St. Louis City, MO (295100085) Lucas, OH (390950026) Allegheny, PA (420033007) Waukesha, WI (551330027)	Muscatine, IA (191390015) New York, NY (360610079) Mahoning, OH (390990014) Washington, PA (421255001)
Indiana	34	District of Columbia (110010041) Will, IL (171971002) Wayne, MI (261630001) Jefferson, OH (390810017) Trumbull, OH (391550007) Brooke, WV (540090005)	District of Columbia (110010042) Muscatine, IA (191390015) St. Louis City, MO (295100085) Lucas, OH (390950024) Allegheny, PA (420030095) Dane, WI (550250047)	Cook, IL (170310022) Bullitt, KY (210290006) New York, NY (360610062) Lucas, OH (390950026) Allegheny, PA (420033007) Milwaukee, WI (550790059)	Cook, IL (170310050) McCracken, KY (211451004) New York, NY (360610079) Mahoning, OH (390990014) Cumberland, PA (420410101) Waukesha, WI (551330027)	Cook, IL (170314007) Warren, KY (212270007) Cuyahoga, OH (390350027) Montgomery, OH (391130031) Washington, PA (421255001)	Saint Clair, IL (171630010) Anne Arundel, MD (240031003) Cuyahoga, OH (390350034) Preble, OH (391351001) Sumner, TN (471650007)
Iowa	9	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Will, IL (171971002)	Elkhart, IN (180390003)	St. Louis City, MO (295100085)

TABLE IV.C–18—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)			
Kansas	2	Muscatine, IA (191390015)	Milwaukee, WI (550790059)				
Kentucky	33	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)
		Will, IL (171971002)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Anne Arundel, MD (240031003)
		Wayne, MI (261630001)	St. Louis City, MO (295100085)	New York, NY (360610062)	New York, NY (360610079)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)
		Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)	Montgomery, OH (391130031)	Preble, OH (391351001)
		Trumbull, OH (391550007)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Washington, PA (421255001)	Sumner, TN (471650007)	Brooke, WV (540090005)
		Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)			
Maryland	5	District of Columbia (110010041)	District of Columbia (110010042)	New York, NY (360610062)	New York, NY (360610079)	Cumberland, PA (420410101)	
Massachusetts	1	New York, NY (360610062)					
Michigan	28	District of Columbia (110010041)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)	Will, IL (171971002)
		Elkhart, IN (180390003)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Warren, KY (212270007)	St. Louis City, MO (295100085)	Cuyahoga, OH (390350027)
		Cuyahoga, OH (390350034)	Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)	Montgomery, OH (391130031)
		Preble, OH (391351001)	Trumbull, OH (391550007)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Washington, PA (421255001)	Sumner, TN (471650007)
		Brooke, WV (540090005)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)		
Minnesota	4	Muscatine, IA (191390015)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)		
Missouri	20	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)	Will, IL (171971002)	Elkhart, IN (180390003)
		Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Bullitt, KY (210290006)	McCracken, KY (211451004)	Warren, KY (212270007)
		Jefferson, OH (390810017)	Lucas, OH (390950026)	Montgomery, OH (391130031)	Preble, OH (391351001)	Sumner, TN (471650007)	Dane, WI (550250047)
		Milwaukee, WI (550790059)	Waukesha, WI (551330027)				
Nebraska	2	Muscatine, IA (191390015)	Milwaukee, WI (550790059)				
New Jersey	5	District of Columbia (110010041)	Anne Arundel, MD (240031003)	New York, NY (360610062)	New York, NY (360610079)	Cumberland, PA (420410101)	
New York	9	District of Columbia (110010041)	District of Columbia (110010042)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)
		Lucas, OH (390950024)	Lucas, OH (390950026)	Cumberland, PA (420410101)			
North Carolina	3	Baltimore City, MD (245100035)	New York, NY (360610062)	New York, NY (360610079)			
Ohio	29	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)
		Will, IL (171971002)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Bullitt, KY (210290006)
		McCracken, KY (211451004)	Warren, KY (212270007)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	Wayne, MI (261630001)	St. Louis City, MO (295100085)
		New York, NY (360610062)	New York, NY (360610079)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Cumberland, PA (420410101)	Washington, PA (421255001)
		Sumner, TN (471650007)	Brooke, WV (540090005)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)	
Pennsylvania	32	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)
		Will, IL (171971002)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Bullitt, KY (210290006)
		Warren, KY (212270007)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	Wayne, MI (261630001)	New York, NY (360610062)	New York, NY (360610079)
		Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)	Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)
		Montgomery, OH (391130031)	Preble, OH (391351001)	Trumbull, OH (391550007)	Sumner, TN (471650007)	Brooke, WV (540090005)	Dane, WI (550250047)

TABLE IV.C–18—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		Milwaukee, WI (550790059)	Waukesha, WI (551330027)				
Tennessee	21	Cook, IL (170314007) Muscatine, IA (191390015) Jefferson, OH (390810017) Trumbull, OH (391550007)	Saint Clair, IL (171630010) Bullitt, KY (210290006) Lucas, OH (390950024) Allegheny, PA (420033007)	Will, IL (171971002) McCracken, KY (211451004) Lucas, OH (390950026) Washington, PA (421255001)	Elkhart, IN (180390003) Warren, KY (212270007) Mahoning, OH (390990014)	Floyd, IN (180431004) Wayne, MI (261630001) Montgomery, OH (391130031)	Vigo, IN (181670023) St. Louis City, MO (295100085) Preble, OH (391351001)
Virginia	7	District of Columbia (110010041) Cumberland, PA (420410101)	District of Columbia (110010042)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	New York, NY (360610062)	New York, NY (360610079)
West Virginia	35	District of Columbia (110010041) Elkhart, IN (180390003) Anne Arundel, MD (240031003) Cuyahoga, OH (390350027) Montgomery, OH (391130031) Washington, PA (421255001)	District of Columbia (110010042) Floyd, IN (180431004) Baltimore City, MD (245100035) Cuyahoga, OH (390350034) Preble, OH (391351001) Sumner, TN (471650007)	Cook, IL (170310050) Vigo, IN (181670023) Wayne, MI (261630001) Jefferson, OH (390810017) Trumbull, OH (391550007) Dane, WI (550250047)	Cook, IL (170314007) Muscatine, IA (191390015) St. Louis City, MO (295100085) Lucas, OH (390950024) Allegheny, PA (420030095) Milwaukee, WI (550790059)	Saint Clair, IL (171630010) Bullitt, KY (210290006) New York, NY (360610062) Lucas, OH (390950026) Allegheny, PA (420033007) Waukesha, WI (551330027)	Will, IL (171971002) Warren, KY (212270007) New York, NY (360610079) Mahoning, OH (390990014) Cumberland, PA (420410101)
Wisconsin	6	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Will, IL (171971002)	Elkhart, IN (180390003)	Muscatine, IA (191390015)

b. Results of 8-Hour Ozone Contribution Modeling

In this section, we present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the ozone NAAQS. As described previously in section IV.B., states which contribute 0.8 ppb or more to 8-hour ozone nonattainment or maintenance in another state are identified as states with contributions to downwind attainment and maintenance sites large enough to warrant further analysis. We performed air quality modeling to quantify the contributions to 8-hour ozone from emissions in each of the following 37 states individually: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland combined with the District of Columbia, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.

We calculated each state's contribution to each of the 11 monitoring sites that are projected to be nonattainment and each of 14 [53] sites that are projected to have maintenance problems for the 8-hour ozone NAAQS in the 2012 Base Case. The largest contribution from each state to 8-hour ozone nonattainment in downwind sites is provided in Table IV.C–19. The largest contribution from each state to 8-hour ozone maintenance in downwind sites is also provided in Table IV.C–19. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the 8-hour ozone NAAQS are provided in the AQMTSD.

TABLE IV.C–19—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind State	Largest downwind contribution to nonattainment for ozone (ppb)	Largest downwind contribution to maintenance for ozone (ppb)
Alabama	4.7	4.7
Arkansas	1.4	1.8
Connecticut	1.7	1.6
Delaware	3.3	2.5
Florida	0.8	2.1
Georgia	2.1	1.7

[53] For two of the 16 projected maintenance sites (Harris Co., Texas sites 482011015 and 482011035) there were less than 5 days with 8-hour ozone predictions of at least 70 ppb. Thus, we did not calculate contributions for these two maintenance sites.

TABLE IV.C–19—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES—Continued

Upwind State	Largest downwind contribution to nonattainment for ozone (ppb)	Largest downwind contribution to maintenance for ozone (ppb)
Illinois	0.8	0.6
Indiana	1.1	1.0
Iowa	0.3	0.3
Kansas	0.6	0.8
Kentucky	2.3	1.8
Louisiana	11.4	10.6
Maine	0.0	0.0
Maryland/Washington, DC	6.1	4.2
Massachusetts	0.6	0.5
Michigan	0.9	0.5
Minnesota	0.1	0.2
Mississippi	5.2	2.5
Missouri	0.7	0.6
Nebraska	0.2	0.2
New Hampshire	0.1	0.1
New Jersey	16.8	15.8
New York	0.4	22.7
North Carolina	1.7	2.0
North Dakota	0.1	0.0
Ohio	2.8	2.6
Oklahoma	2.1	2.7
Pennsylvania	8.9	8.1
Rhode Island	0.1	0.1
South Carolina	0.6	0.8
South Dakota	0.0	0.0
Tennessee	1.6	3.0
Texas	1.6	0.6
Vermont	0.0	0.1
Virginia	4.2	4.5
West Virginia	2.7	2.3
Wisconsin	0.3	0.2

Based on the state-by-state contribution analysis, there are 22 states and the District of Columbia [54] which contribute 0.8 ppb or more to downwind 8-hour ozone nonattainment. These states are: Alabama, Arkansas, Connecticut, Delaware, the District of Columbia, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, New Jersey, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, and West Virginia. In Table IV.C–20, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.8 ppb or more (i.e., the upwind state to downwind nonattainment "linkages").

There are 22 states and the District of Columbia which contribute 0.8 ppb or more to downwind 8-hour ozone maintenance. These states are: Alabama, Arkansas, Connecticut, Delaware, the District of Columbia, Florida, Georgia, Indiana, Kansas, Kentucky, Louisiana, Maryland, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Virginia, and West Virginia. In Table IV.C–21, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.8 ppb or more (i.e., the upwind state to downwind nonattainment "linkages").

TABLE IV.C–20—UPWIND STATE TO DOWNWIND NONATTAINMENT "LINKAGES" FOR 8-HOUR OZONE

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Alabama	8	East Baton Rouge, LA (220330003) Harris, TX (482011039)	Brazoria, TX (480391004) Tarrant, TX (484391002)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)
Arkansas	3	East Baton Rouge, LA (220330003)	Brazoria, TX (480391004)	Tarrant, TX (484391002)			

[54] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland. Under our analysis, Maryland and the District of Columbia are linked as significant contributors to the same downwind nonattainment counties.

TABLE IV.C–20—UPWIND STATE TO DOWNWIND NONATTAINMENT "LINKAGES" FOR 8-HOUR OZONE—Continued

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Connecticut	1	Suffolk, NY (361030009)					
Delaware	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Florida	2	Harris, TX (482010062)	Tarrant, TX (484391002)				
Georgia	7	Brazoria, TX (480391004) Tarrant, TX (484391002)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)	Harris, TX (482011039)
Illinois	2	Suffolk, NY (361030009)	Harris, TX (482010055)				
Indiana	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Kentucky	6	Suffolk, NY (361030002)	Philadelphia, PA (421010024)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482011039)
Louisiana	7	Brazoria, TX (480391004) Tarrant, TX (484391002)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)	Harris, TX (482011039)
Maryland	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Michigan	1	Suffolk, NY (361030009)					
Mississippi	8	East Baton Rouge, LA (220330003) Harris, TX (482011039)	Brazoria, TX (480391004) Tarrant, TX (484391002)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)
New Jersey	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
North Carolina	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Ohio	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Oklahoma	1	Tarrant, TX (484391002)					
Pennsylvania	2	Suffolk, NY (361030002)	Suffolk, NY (361030009)				
Tennessee	7	Philadelphia, PA (421010024) Harris, TX (482011039)	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)
Texas	1	East Baton Rouge, LA (220330003)					
Virginia	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
West Virginia	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			

TABLE IV.C–21—UPWIND STATE TO DOWNWIND MAINTENANCE "LINKAGES" FOR 8-HOUR OZONE

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Alabama	6	DeKalb, GA (130890002)	Fulton, GA (131210055)	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX (482011050)	Tarrant, TX. (484392003).
Arkansas	4	Dallas, TX (481130069)	Dallas, TX (481130087)	Harris, TX (482011050)	Tarrant, TX (484392003)		
Connecticut	1	Westchester, NY (361192004)					
Delaware	1	Bucks, PA (420170012)					
Florida	4	DeKalb, GA (130890002)	Fulton, GA (131210055)	Harris, TX (482010024)	Harris, TX (482010029)		
Georgia	4	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX (482011050)	Tarrant, TX (484392003)		
Indiana	4	Fairfield, CT (90010017)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA (420170012)		
Kansas	1	Dallas, TX (481130069)					
Kentucky	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).

TABLE IV.C–21—UPWIND STATE TO DOWNWIND MAINTENANCE "LINKAGES" FOR 8-HOUR OZONE—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Louisiana	6	Dallas, TX (481130069)	Dallas, TX (481130087)	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX (482011050)	Tarrant, TX. (484392003).
Maryland	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
Mississippi	7	DeKalb, GA (130890002) Tarrant, TX (484392003)	Fulton, GA (131210055)	Dallas, TX (481130087)	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX. (482011050).
New Jersey	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
New York	5	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Bucks, PA (420170012)	
North Carolina	5	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA (420170012)	
Ohio	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
Oklahoma	3	Dallas, TX (481130069)	Dallas, TX (481130087)	Tarrant, TX (484392003)			
Pennsylvania	5	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	
South Carolina	2	Fulton, GA (131210055)	Harris, TX (482010029)				
Tennessee	5	DeKalb, GA (130890002)	Fulton, GA (131210055)	Bucks, PA (420170012)	Harris, TX (482010024)	Harris, TX (482011050)	
Virginia	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
West Virginia	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).

D. Proposed Methodology To Quantify Emissions That Significantly Contribute or Interfere With Maintenance

In this section, EPA explains its general approach to quantifying the amount of emissions that represent significant contribution and interference with maintenance. EPA then applies that approach for the three different NAAQS being addressed in today's notice: The 1997 ozone NAAQS, the 1997 annual $PM_{2.5}$ NAAQS and the 2006 24-hour $PM_{2.5}$ NAAQS.

With respect to the 1997 ozone NAAQS, we apply this methodology to fully quantify the significant contribution and interference with maintenance for 16 states. We also use the methodology to quantify, for 10 additional states, NO_X emissions reductions that are necessary to make measurable progress towards eliminating their significant contribution and interference with maintenance. Additional information gathering and analysis is needed to determine the extent to which further reductions from these states may be needed to fully eliminate significant contribution and interference with maintenance with the ozone NAAQS. As is further explained in section IV.D.2.b EPA will fully address this issue in a future rulemaking as quickly as possible.

With respect to the annual $PM_{2.5}$ NAAQS, this proposal finds that 24 eastern states have SO_2 and NO_X emission reduction responsibilities. We apply the proposed methodology to fully quantify the SO_2 and NO_X emissions from each of these states that significantly contribute to or interfere with maintenance in downwind areas.

With respect to the 24-hour $PM_{2.5}$ NAAQS, this proposal finds that 25 eastern states have emission reduction responsibilities. We use the proposed methodology to quantify emissions reductions that these states must achieve to make, at a minimum, measurable progress towards eliminating the state's significant contribution and interference with maintenance. Further analysis will be needed to determine if these reductions are sufficient to fully eliminate any or all of these states' significant contribution and interference with maintenance for purposes of the 24-hour $PM_{2.5}$ standard. As is explained in greater detail in section IV.D.2.a, EPA intends to finalize, to the extent possible a determination of the complete amount of emissions that represents significant contribution and interference with maintenance. If further analysis shows that the amounts of emissions proposed in today's notice include all emissions that significantly contribute or interfere with maintenance of the 24-hour $PM_{2.5}$ standard or that more SO_2 emissions should be included, we believe that we will be able to issue a supplemental proposal and finalize a rule fully quantifying significant contribution and interference with maintenance with respect to the 24-hour $PM_{2.5}$ standard. If further analysis shows that other reductions should be considered as part of significant contribution or interference with maintenance with respect to the 24-hour $PM_{2.5}$ standard these emissions would be fully addressed in a separate rulemaking effort.

1. Explanation of Proposed Approach To Quantify Significant Contribution

After using air quality analysis to identify upwind states that are "linked" to downwind air quality monitoring sites with nonattainment and maintenance problems because the upwind states' emissions contribute one percent or more to the air quality value at the downwind site, EPA quantifies the portion of each state's contribution that constitutes its "significant contribution" and "interference with maintenance."

This section describes the methodology developed by EPA for this analysis and then explains how that methodology is applied to measure significant contribution and interference with maintenance with respect to the $PM_{2.5}$ NAAQS and the ozone NAAQS. For this portion of the analysis, EPA expands upon the methodology used in the NO_X SIP Call and CAIR, but modifies it in significant respects. In the NO_X SIP Call and CAIR, EPA's

methodology relied upon defining significant contribution as those emissions that could be removed with the use of "highly cost effective" controls. In this action, rather than relying solely on determining reductions based on "highly cost effective" controls, EPA uses a number of factors that account for both cost and air quality improvement. Furthermore, unlike the NO_X SIP Call and CAIR where EPA only defined an amount of reductions needed to address significant contribution to nonattainment, EPA is proposing to define an amount of emissions reductions that addresses both significant contribution to nonattainment and interference with maintenance.

The methodology takes into account both the DC Circuit Court's determination that EPA may consider cost when measuring significant contribution, *Michigan,* 213 F.3d at 679, and its rejection of the manner in which cost was used in the CAIR analysis, *North Carolina,* 531 F.3d at 917. It also recognizes that the Court accepted—but did not require—EPA's use of a single, uniform cost threshold to measure significant contribution. *Michigan,* 213 F.3d at 679.

The methodology defines each state's significant contribution and interference with maintenance as the emissions that can be eliminated for a specific cost. Unlike the NO_X SIP Call and CAIR, where EPA's significant contribution analysis had a regional focus, the methodology used in today's proposal focuses on state-specific factors. The methodology uses a multi-step process to analyze costs and air quality impacts, identify appropriate cost thresholds, quantify reductions available from EGUs in each state at those thresholds, and consider the impact of variability in EGU operations.

In step one, EPA identifies what emissions reductions are available at various costs, quantifying emissions reductions that would occur within each state at ascending costs per ton of emissions reductions. For purposes of this discussion, we refer to these as "cost curves".

In step two, EPA uses an air quality assessment tool to estimate the impact that the combined reductions available from upwind contributing states and the downwind state, at different cost-per-ton levels, would have on air quality at downwind monitor sites that had nonattainment and/or maintenance problems.

In step three, EPA examines cost and air quality information to identify cost "breakpoints." Breakpoints are the places where there is a noticeable change on one of the cost curves, such as a point where a large reduction occurs because a certain type of emissions control becomes cost-effective. EPA then uses a multi-factor assessment to determine the amount of emissions that represents significant contribution to nonattainment and interference with maintenance. The factors considered include both the air quality and cost considerations used in developing the breakpoints along with additional air quality and cost considerations. This assessment is performed for each transported NAAQS pollutant or precursor which EPA has concluded must be regulated due to its impact on downwind receptors. In this rule, as discussed in section IV.B, EPA is proposing to regulate SO_2 and NO_X. The methodology also allows EPA, where appropriate, to define multiple cost thresholds that vary for a particular pollutant for different upwind states.

In step four, EPA quantifies the emissions reductions available in each "linked" state at the appropriate cost threshold. This information is then used to develop a state "budget," representing the remaining emissions for the state in an average year, and to identify a variability limit associated with that budget. These budgets and variability limits are used to develop enforceable requirements under the proposed and two alternative remedy options. State emissions budgets are discussed in section IV.E and the variability limit is discussed in section IV.F.

EPA's proposed methodology considers both cost and air quality factors to address complex circumstances. We believe it is important to consider both factors because circumstances related to different downwind receptors can vary and consideration of multiple factors can help EPA appropriately identify each state's significant contribution under different circumstances. For instance, there may be cases when upwind states contributing to a specific downwind nonattainment area have already done a great deal to reduce emissions while the downwind state in which the nonattainment area is located has done very little. Conversely, the downwind state may have made large reductions while one or more contributing upwind states may have done very little. There may be cases where some states (upwind or downwind) have large emissions (and a correspondingly large impact downwind) not because their sources are poorly controlled, but because they have a greater number of sources—the operation of which is critical to the reliability of the electric grid. Conversely, there may be cases where a state (upwind or downwind) contributes less in total emissions because it has a smaller number of plants, but those plants are poorly controlled and could be better controlled at a relatively low cost.

Air quality factors alone are not able to discern these types of differences. Using both air quality and cost factors allows EPA to consider the full range of circumstances and state-specific factors that affect the relationship between upwind emissions and downwind nonattainment and maintenance problems. For example, considering cost takes into account the extent to which existing plants are already controlled as well as the potential for, and relative difficulty of, additional emissions reductions. Therefore, EPA believes that it is appropriate to consider both cost and air quality metrics when quantifying each state's significant contribution.

This methodology is consistent with the statutory mandate in section 110(a)(2)(D)(i)(I) which requires upwind states to prohibit emissions that significantly contribute to nonattainment or interfere with maintenance in another state, but does not shift the responsibility for achieving or maintaining the NAAQS to the upwind state.

In developing and implementing this methodology, EPA was cognizant of a number of factors. First, in many areas, transported emissions are a key component of the downwind air quality problem. Second, there are large amounts of low cost emission reduction opportunities in upwind states. Third, EPA recognizes that section 110(a)(2)(D) does not grant EPA authority to require emissions reductions solely because they provide large health and environmental benefits: reductions required pursuant to section 110(a)(2)(D)(i)(I) must be related to the goal of eliminating upwind state emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas.

Fourth, EPA is cognizant of the relationship between the upwind and downwind state requirements in the Act. The Act requires upwind states to eliminate significant interstate pollution transport under section 110(a)(2)(D). It also requires each state to assure attainment and maintenance of the NAAQS within its borders. Thus, a downwind state must adopt controls to demonstrate timely attainment of the NAAQS despite any pollution transport from upwind states that is not eliminated under section 110(a)(2)(D).

Given this structure, interpreting significant contribution and interfere with maintenance inherently involves a policy decision on how much emissions control responsibility should be assigned to upwind states, and how much responsibility should be left to downwind states. In virtually all areas, $PM_{2.5}$ and ozone problems result from a combination of local, in-state, and upwind state emissions. EPA's proposed methodology for determining what portion of a state's total contribution is its significant contribution and interference with maintenance is intended to assign a substantial but reasonable amount of responsibility to upwind states.

There are several reasons that EPA believes upwind state sources contributing to air quality degradation in a downwind state should bear substantial responsibility to control their emissions. First, the plain language of this good neighbor provision requires upwind states to prohibit emissions that significantly contribute to nonattainment or interfere with maintenance in a downwind state. Second, interstate pollution transport increases pollution levels and health risks in the downwind state. Third, the influx of pollution from upwind states raises the pollution level in a downwind state, making it necessary for the downwind state to obtain deeper pollution reductions to attain and maintain air quality standards, which increases costs of control in the downwind state. Fourth, from the standpoint of a downwind state, the pollution contribution of each upwind state adds up to a larger, cumulative degradation of the downwind state's air quality. Fifth, reducing interstate pollution enhances prospects that attainment in downwind states can be achieved within the Act's deadlines and as expeditiously as practicable. All of these points support the position that upwind state sources should bear substantial responsibility to control their emissions.

On the other hand, the proposed methodology ensures that upwind states are not required to shoulder the entire responsibility for the downwind state's attainment and maintenance of the NAAQS. Among other things, our methodology implicitly assumes controls at the same cost per ton level in the downwind state as in the upwind contributing states.[55] In addition, in almost all cases, states with downwind nonattainment and maintenance areas are also required to reduce emissions based on the fact that they are also upwind states that are "linked" to other downwind states with nonattainment and maintenance problems.

The proposed methodology also directly ties each state's reduction requirements to EPA's analysis of that state's significant contribution and interference with maintenance. The required reductions would provide very substantial air quality improvements. For the annual $PM_{2.5}$ standard, EPA projects that this rule will help assure that all but one area in the East attain the standard by 2014. It will also help a number of areas achieve the standard earlier. The methodology provides similar assistance for ozone, assuring upwind reductions that will mitigate the amount that downwind states may need to do. It reduces ozone concentration levels in 2012 and helps assure that even absent this additional local control, all but 3 areas' nonattainment and maintenance problems are resolved by 2014. Air quality in the few areas with remaining problems will be improved, providing both health benefits and assistance for these local areas in meeting the NAAQS requirements.

a. Step 1. Emissions Reductions Cost Curves

The first step in EPA's methodology for determining the quantity of emissions that represents each state's significant contribution is to identify reductions available at different costs. To do so, EPA developed a set of cost curves that show, at various cost increments, the available emissions reductions for EGUs in a state. In other words, EPA determined for specific cost per ton thresholds, the emissions reductions that would be achieved in a state if all EGUs in that state used all emission controls and emission reduction measures available at that cost threshold. The zero point of the curve shows what emissions would occur absent any additional investment in emissions reductions (*i.e.*, the base case emissions). Additional points on the curves show the emissions that would occur after the installation of all controls that could be installed at specific cost levels (dollars per ton of emissions reduced). In developing these cost curves, EPA used IPM to identify costs for reducing emissions from EGUs by modeling emissions reductions available at multiple cost increments. EPA also applied the same cost constraint for each state in each modeling iteration. For example, in one iteration, all covered sources in the states examined were constrained to emit at levels achievable by the application of all controls available for $100/ton. In a second iteration, all states examined were assumed to achieve all reductions in each state that were available at $200/ton. The resulting cost curves for SO_2 and annual NO_X can be found in section IV.D.2.a of this preamble and the curves for ozone season NO_X in section IV.D.2.b. For more detail on the development of the cost curves, *see* the TSD, "Analysis to Quantify Significant Contribution," in the docket for this rule.

Although the cost curves presented in this proposal only include EGU reductions, EPA also conducted a preliminary assessment of reductions available for source categories other than EGUs. This preliminary assessment suggested that there likely would be very large emissions reductions available from EGUs before costs reach the point for which non-EGU sources have available reductions. EPA therefore initially created cost curves based solely on reductions from EGUs and determined appropriate cost thresholds based on that analysis. EPA then re-examined non-EGUs to determine the accuracy of its initial assumptions that there were little or no reductions available from non-EGUs at costs lower than the thresholds that EPA had chosen. EPA's analysis of the costs of and opportunities for non-EGU emissions reductions is discussed in more detail in section IV.D.3, later. For the reasons explained in that section, EPA believes there are little or no non-EGU reductions available at the cost thresholds used in this rule. Therefore, EPA believes it is reasonable at this time to use cost curves that include only EGU reductions. However, EPA is continuing to conduct analyses and believes that it will be necessary to further consider non-EGU emission reduction opportunities in future transport rules.

To develop cost curves, emissions available at various costs were assessed in 2012 for ozone season NO_X and 2014 for annual NO_X and SO_2. As described in section V.C, EPA coordinated the deadlines for eliminating significant contribution and interference with maintenance with the NAAQS attainment deadlines for downwind states and determined that all significant contribution and interference with maintenance with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS must be eliminated by 2014, or as expeditiously as practicable. The cost curves show, among other things, that the amount of emissions reductions that can be achieved for a given cost varies over

[55] We also recognize that there can be reasons to depart from an equal cost per ton allocation of responsibility before a receptor's attainment and maintenance problem is fully resolved, such as when a receptor's air quality problem has an unusually high local component.

time. This is true because, among other things, control options that are available in a longer timeframe may not be available in a shorter timeframe. For instance, it takes approximately 27 months to build a flue gas desulfurization unit (FGD, or "scrubber") to reduce SO_2 emissions (Boilermaker Labor Analysis and Installation Timing, USEPA, March 2005), so if this rule is finalized in mid-2011, emissions reductions from scrubbers by 2012 or 2013 can only reasonably be achieved if that scrubber either exists today, or if it is currently under construction. However, by 2014, additional reductions could be obtained from the construction of new scrubbers. It takes approximately 21 months to construct a selective catalytic reduction (SCR) unit to reduce emissions of NO_X. (Boilermaker Labor Analysis and Installation Timing, USEPA, March 2005).

There are approximately 30 months between mid-2011 (when the Agency anticipates finalizing this rule) and January 2014 (the proposed Phase 2 compliance deadline). EPA believes this is sufficient time for sources to install the advanced emissions controls projected to be retrofit. EPA expects about 14 GW of FGD and less than 1 GW of SCR capacity to be retrofit for Phase 2 of this rule. This is significantly less than the capacity that was retrofit in the same length of time after CAIR was finalized. EPA is not aware of problems or issues with sources meeting the CAIR compliance deadlines, either in equipment deliveries or labor availability. EPA believes the proposed Transport Rule compliance deadlines are reasonable, and will result in emissions reductions as quickly as practicable, delivering health benefits to the public and aiding states with NAAQS attainment deadlines.

EPA requests comment on the schedule for scrubber and SCR installations, the availability of boilermaker labor, and any comment on whether there might be alternative post-combustion cost-effective technologies that could reduce SO_2 and/or NO_X emissions. We also solicit comment on whether advanced coal preparation processes might provide emissions reductions at the significant contribution cost levels identified in this proposal, whether such processes have been commercialized, and what the costs will be. In addition, EPA seeks comment on, whether other factors, such as other EPA regulatory actions, will create an increase in boilermaker demand earlier than today's proposal, in 2010 and beyond. We solicit comments on whether other factors might increase demand for boilermakers or control equipment, and what these factors would be. Comments in support of or opposed to the proposed compliance deadlines should include information to support the commenter's position.

Unlike add-on pollution controls such as scrubbers and SCRs, EPA believes that low-NO_X burners could be installed by 2012. *See* TSD, "Installation Timing for Low NO_X Burners," in the docket for this rule.

EPA also believes that sources can switch coals by 2012. Eastern bituminous coals used for power generation typically have more than sufficient sulfur content to facilitate highly efficient collection of fly ash in a cold-side electrostatic precipitator (ESP). Some ESPs that operate at acceptably high collection efficiency when using a high-or medium-sulfur bituminous coal may experience some loss in collection efficiency when a lower sulfur coal is used. Whether this occurs on a specific unit, and the extent to which it occurs, would depend on the design margins built into the existing ESP, the percentage change in coal sulfur content, and other factors. Relatively inexpensive practices to maintain high ESP performance on lower sulfur bituminous coals are available and are being used successfully where necessary. These include a range of upgrades to ESP components and flue gas conditioning.

EPA assumes in the Transport Rule analysis that it will not be necessary for units that switch from higher to lower sulfur bituminous to make a costly replacement of the ESP. EPA's analysis therefore does not add capital or operations and maintenance costs for coal switching from higher to lower sulfur bituminous coals.

EPA's analysis does not allow a unit designed for bituminous to switch to (very low sulfur) subbituminous coal unless the unit has demonstrated that capability in the past. EPA assumes units with that capability have already made any investments needed to handle a switch to subbituminous coals. EPA therefore assumes that any modeled coal switching from bituminous to subbituminous has no cost or schedule impact.

EPA requests comment on the reasonableness of EPA's assumption that coal switching within the bituminous coal grades will have relatively little cost or schedule impact on most units.

b. Step 2. Performing the Air Quality Assessment

In the second step, EPA uses an air quality assessment tool to estimate the impact of the upwind emissions reductions on downwind ambient concentrations.[56] This tool is useful for identifying cost breakpoints for significant improvements in downwind air quality changes, including estimated effects on downwind attainment. While less rigorous than the air quality models used for attainment demonstrations, EPA believes this air quality assessment tool is acceptable for assessing the impact of numerous options on upwind reductions in the process of identifying upwind state significant contribution. It allows the Agency to analyze many more potential scenarios than the time- and resource-intensive more refined air quality modeling would permit. This tool assesses the impact that reductions at a given cost breakpoint from all of the contributing states (as well as the state with the nonattainment area itself) had on pollutant concentrations at that downwind area. The resulting information is used in step three. For each downwind area with a nonattainment and/or maintenance problem, it shows the total improvement in air quality for each cost level and associated pollutant reduction, the amount of the remaining problem caused by each upwind state (by constituent), and the amount of the remaining problem caused by sources within the state (by constituent). It also shows, overall, how much of the downwind air quality problem had been addressed at different cost levels. More detail on the tool itself, what EPA has done to verify the underlying assumptions, and the specific application of the tool to examining significant contribution for ozone and $PM_{2.5}$ can be found in the TSD, "Analysis to Quantify Significant Contribution," in the docket for this rule.

c. Step 3. Identifying Appropriate Cost Thresholds

In the third step of this analysis, EPA examines the information developed in the first two steps to identify potential cost thresholds. It then uses a multi-factor assessment to identify which cost

[56] As is discussed in the RIA, EPA also used the CAMx model to perform air quality analysis of its proposed remedy to address significant contribution. Results from this modeling will not exactly correspond to results from the air quality tool both because the inputs to the air quality modeling are different and the sophisticated model more fully accounts for the complex air chemistry interactions. The full air quality modeling looks at the remedy, including reductions in upwind states that do not contribute as well as the impacts of the variability provisions discussed later in this section. It also provides a metric against which to evaluate the air quality assessment tool.

threshold [57] or thresholds should be used to quantify states' significant contribution and interference with maintenance. This new methodology responds to the Court's statements in *North Carolina* v. *EPA* both criticizing the manner in which cost was used in the CAIR rule and acknowledging its prior acceptance (in *Michigan* v. *EPA*, 213 F.3d 663) of EPA's use of a uniform cost threshold and the uniform control requirements associated with the use of such a cost threshold. *See North Carolina* v. *EPA*, 531 F.3d at 908, 917.920. In both the NO_X SIP Call and CAIR, EPA evaluated the cost of controls relative to the cost of controls required by other CAA regulations to identify a single cost threshold referred to as the "highly-cost-effective" threshold. In contrast, in this proposed rule, EPA considers multiple factors to identify appropriate cost thresholds, allowing EPA to give greater weight to air quality considerations and making it possible to tailor the significant contribution measurement more closely to different conditions in different groups of states.

This step of the analysis begins with an examination of the cost and air quality data to identify breakpoints on the emissions reductions cost curves developed in steps 1 and 2 related to (1) air quality (*e.g.*, points at which all areas (other than those with an unusually predominant local pollution problem) reach attainment and have maintenance fully addressed), and/or (2) cost (*e.g.*, points at which significant reductions are available because a certain technology is widely deployed). EPA identifies potential breakpoints and then uses a multi-factor assessment to evaluate whether one or more of the potential breakpoints represent a reasonable cost at which to define significant contribution for some or all upwind states. The factors in this multi-factor assessment can be divided into two broad categories: Those that focus on air quality considerations and those that focus on cost considerations. Air quality considerations include, for example, how much air quality improvement in downwind states results from upwind state emissions reductions at different levels; whether, considering upwind emissions reductions and assumed local (in-state) reductions, the downwind air quality problems would be resolved; and the components of the remaining downwind air quality problem (*e.g.*, is it a predominantly local or in-state problem, or does it still contain a large upwind component). Cost considerations include, for example, how the cost per ton compares with the cost per ton of existing federal and state rules for the same pollutant, and whether the cost per ton is consistent with the cost per ton of technologies already widely deployed (similar to the highly-cost-effective criteria used in both the NO_X SIP Call and CAIR); the cost increase required to achieve the next increment of air quality improvement; and whether, given timing considerations, emissions reductions requirements could be more costly than indicated in the modeling because sources could choose one short-term solution and then switch to another long-term solution (*e.g.*, switching coals can involve plant modifications. While these costs are low when amortized over a number of years, if a source quickly installs controls, and switches coals again, costs may be higher than projected).

Because upwind state sources should bear substantial responsibility for controlling emissions that contribute to air quality degradation in downwind states, EPA believes that cost per ton levels that are consistent with widely deployed existing controls, or are within the cost per ton range of controls already required by existing and proposed Federal and State rules (*i.e.*, similar to the highly cost effective concept in the NO_X SIP Call and CAIR), are reasonable for upwind states from a cost standpoint. Higher cost per ton levels also may be reasonable for upwind states based on examination of air quality and cost factors. One reason is that achieving attainment and maintenance of the air quality standard may require controls in upwind and downwind states that are more costly than previous controls (particularly if it is a new standard).

Based on this multi-factor assessment, EPA identifies a specific cost per ton threshold for quantifying the amount of significant contribution from each state for each precursor pollutant. While we continue to believe that under certain circumstances it may be appropriate for us to use a single uniform cost per ton threshold to quantify significant contribution for all states, we believe it is also important to retain the flexibility to use multiple cost thresholds. For example, we believe it is appropriate to use multiple thresholds where one group of states can, for a lower cost, eliminate nonattainment and maintenance for all the downwind nonattainment and maintenance areas to which they are linked.

d. Step 4. Identify Required Emissions Reductions

In the final step of this analysis, EPA uses the cost thresholds identified in the previous step to determine, on a state-by-state basis, the amount of emissions that could be reduced at a specific cost. The results of this analysis are used to develop the state budgets and variability limits, which are in turn used to implement the requirements to eliminate significant contribution and interference with maintenance. *See* sections IV.E and IV.F.

2. Application

The discussion that follows explains how the methodology described previously was applied to quantify significant contribution with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. EPA also believes that the methodology proposed today could also be used to address transport concerns under other NAAQS, including revisions to the ozone and $PM_{2.5}$ NAAQS.

All of the air quality considerations included in the multi-factor assessment are based on analysis using the air quality assessment tool. EPA believes that it is appropriate to use this tool because of the advantages it has over more refined air quality modeling to perform analysis of a large number of scenarios very quickly (more refined air quality modeling can take several months, while multiple scenarios can be evaluated using the air quality assessment tool in a single day). EPA has done more refined air quality modeling of the proposed emissions budgets. The more refined air quality modeling confirms EPA's overall methodology, but does suggest that, in the case of daily $PM_{2.5}$, the air quality assessment tool slightly over-predicts the air quality benefit of the proposed reductions.

For this reason, EPA is also requesting comment on whether we should modify our conclusions regarding the amount of specific states' significant contribution and interference with maintenance; whether there are ways to use our air quality modeling in conjunction with the air quality assessment tool to carry out the significant contribution analysis in a way that would not extend the time needed to complete this rulemaking; and whether there are ways to improve the air quality assessment tool.

[57] The cost thresholds identified in today's proposal are specific to the section 110(a)(2)(D) requirements for the states and NAAQS considered in this proposal. They do not represent an agency position on the appropriateness of such cost thresholds for any other application under the Act.

a. Specific Application to $PM_{2.5}$

(1) Year for Quantifying Significant Contribution

EPA's significant contribution analysis for $PM_{2.5}$ used a multi-factor assessment to identify cost thresholds for 2014. EPA believes this is the most appropriate year to consider because it is consistent with attainment dates for both the annual and daily $PM_{2.5}$ standards. Furthermore, EPA believes that 2014 provides sources sufficient lead time to install emissions controls or take other actions necessary to achieve the required reductions. After determining the amount of emissions that represents each state's significant contribution, EPA then considers whether it would be appropriate to establish an interim compliance deadline to ensure that the reductions are achieved as expeditiously as practicable. For this part of the analysis, EPA focused on determining what portion of each state's significant contribution could be eliminated by 2012, the first year in which it would be possible to get reductions following promulgation of this rule in 2011. EPA believes it is possible to achieve much of the required emissions reductions by 2012. EPA also believes that it is important to get the reductions as expeditiously as practicable and to coordinate the compliance dates both with the downwind states" maximum attainment deadlines and with the requirement that they eliminate nonattainment as expeditiously as practicable.

(2) Step 1. Emissions Reductions Cost Curves

This subsection provides more detail on the cost curves that EPA developed to assess the costs of reducing SO_2 and NO_X to address transport related to $PM_{2.5}$. It summarizes the information from the curves and then provides EPA's interpretation of that information. EPA uses the information from the cost curves in step 3 to quantify the cost per ton of emissions reductions which should be used to calculate each state's significant contribution and interference with maintenance, and the resulting state-specific emissions budgets.

To measure significant contribution and interference with maintenance with respect to the $PM_{2.5}$ NAAQS, EPA developed cost curves showing the annual NO_X and annual SO_2 reductions available in 2014 at different cost increments. Specifically, EPA developed cost curves that show reductions available in 2014 from EGUs at various costs (in 2006 $) up to $2,500/ton for annual NO_X, $5,000/ton for ozone season NO_X, and $2,400/ton for SO_2. For example, this means that EPA examined reductions of annual NO_X that are available at a cost of $2,500 per ton or less. For SO_2, the projected cost considered for reducing a ton of emissions is $2,400 or less.

Table IV.D–1 shows the annual NO_X emissions from EGUs at various levels of control cost for 2014.

TABLE IV.D–1—2014 ANNUAL NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE IN THE TRANSPORT REGION AT VARIOUS COSTS

[(2006 $) per ton (thousand tons)]

Marginal cost per ton	Base case level	$500	$1,500	$2,500
Alabama	119	62	62	50
Connecticut	8	8	8	8
Delaware	6	6	6	6
Florida	196	138	113	80
Georgia	48	46	45	45
Illinois	80	56	56	56
Indiana	201	114	114	107
Iowa	68	56	50	47
Kansas	79	38	36	35
Kentucky	149	72	72	71
Louisiana	46	37	37	28
Maryland	36	36	36	36
Massachusetts	13	13	13	13
Michigan	99	68	68	66
Minnesota	55	38	38	38
Missouri	83	82	61	55
Nebraska	53	34	28	28
New Jersey	27	23	23	20
New York	36	35	32	31
North Carolina	63	63	62	61
Ohio	165	104	98	88
Pennsylvania	205	123	122	86
South Carolina	48	36	36	35
Tennessee	69	29	29	29
Virginia	38	37	37	36
West Virginia	100	54	49	45
Wisconsin	55	44	43	41
Total	2,144	1,455	1,375	1,241

Before applying the information in the cost curves in step 3 of the analysis, EPA evaluated the cost curves to better understand how reductions at various cost levels reflect changes in the generation mix (*e.g.*, dispatch changes, fuel use changes, or installation or operation of controls). From the cost curves, EPA concluded that in 2014, there are large NO_X reductions available at approximately $500/ton. At costs above $500/ton and up to at least $2,500/ton, potential reductions increase slowly. This is because the base case assumed that sources would not

run their SCR units unless they are required to run those SCR units pursuant to mandates other than CAIR (which will be replaced by this rule when it is finalized). This is especially relevant for winter use of SCRs. Even without CAIR, the NO_X SIP Call will provide an incentive to run many SCRs during the ozone season.

The cost curves demonstrate that many of these sources would operate their SCR units when emissions reductions that cost $500/ton are required. In addition, at this $500/ton level some additional units would likely install advanced combustion control technology. Below $500/ton, there are very few other NO_X reductions. Significant additional reductions would not be achieved without application of controls costing more than $2,500/ton. In 2014, more reductions could be achieved with installation of additional add-on controls, such as SCR.

The cost curves for SO_2 show the same effect as those for NO_X (large emissions reductions at relatively low costs and additional reductions at relatively high costs) but the effect was not as pronounced. In 2014, more than 1,000,000 tons of SO_2 reductions can be achieved at a cost of less than $200 per ton. Most of these reductions can be achieved by requiring companies to operate existing scrubbers that they would not have an incentive to run absent the requirements of CAIR. Additional reductions can be achieved at higher costs. For instance, in many cases, companies are currently using lower sulfur coals to comply with CAIR, but there is no guarantee they will continue to do so. Many, but not all, of these reduction opportunities (*e.g.*, operating current equipment and continued use of low sulfur coal) are available at below $500/ton.

Table IV.D–2 shows that in 2014 there are increased SO_2 emission reduction opportunities beyond just operating existing scrubbers and switching to low sulfur coal. Installation of new scrubbers becomes feasible by 2014, thus increasing reduction opportunities at costs between $500/ton and $2,000/ton (and above).

TABLE IV.D–2—2014 SO_2 EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE IN THE TRANSPORT REGION AT VARIOUS COSTS

[(2006$) per ton (thousand tons)]

Marginal cost per ton	Base case level	$100	$200	$500	$1,000	$1,400	$1,800	$2,000	$2,400
Alabama	322	307	257	171	166	146	101	84	71
Connecticut	6	6	6	6	6	3	3	3	3
Delaware	8	9	9	9	9	9	9	8	8
Florida	195	178	171	117	113	111	79	74	70
Georgia	173	166	136	133	117	101	92	86	67
Illinois	200	185	165	165	164	165	161	155	143
Indiana	804	478	433	328	291	284	242	227	190
Iowa	164	140	130	106	105	104	102	101	70
Kansas	65	64	56	49	46	46	33	31	24
Kentucky	740	275	270	248	196	178	127	115	100
Louisiana	95	95	95	95	95	95	95	82	36
Maryland	45	45	45	45	45	45	42	42	40
Massachusetts	17	18	18	10	10	10	9	9	6
Michigan	276	254	253	214	209	207	177	163	116
Minnesota	62	57	55	49	48	48	48	48	46
Missouri	501	289	238	213	212	212	196	183	94
Nebraska	116	119	113	74	73	71	69	45	33
New Jersey	40	40	27	21	21	20	18	17	14
New York	143	142	143	135	118	114	100	70	63
North Carolina	141	141	141	130	114	104	99	91	63
Ohio	841	583	553	408	294	260	236	221	203
Pennsylvania	975	825	441	337	202	175	154	145	125
South Carolina	156	138	137	134	125	83	78	57	42
Tennessee	600	154	131	127	126	108	108	100	79
Virginia	137	134	134	109	106	93	65	54	45
West Virginia	496	179	170	161	160	143	132	119	98
Wisconsin	117	111	108	97	92	89	87	81	64
Total	7,436	5,133	4,435	3,692	3,263	3,025	2,660	2,410	1,912

(3) Step 2. Air Quality Assessment of Potential Emissions Reductions

After developing cost curves to show the state-by-state cost-effective emissions reductions available, EPA used the air quality assessment tool to evaluate the impact these upwind reductions would have on air quality in "linked" downwind nonattainment and maintenance areas. This section summarizes the results of that evaluation and provides analysis that informs EPA's multi-factor assessment, explained in step 3, later.

EPA performed air quality analysis for each downwind receptor with a nonattainment and/or maintenance problem. For each receptor, EPA assessed the air quality improvement resulting when a group of states, consisting of the upwind states that are "linked" to the downwind receptor (*i.e.*, EPA modeling showed that they exceeded the one percent contribution threshold, based on it's 2012 linkage analysis), and the downwind state where the receptor is located, all made the emissions reductions that EPA identified as available at each cost threshold (as described previously). This analysis did not assume any reductions in upwind states covered by this rule but not "linked" to the downwind receptor (even if the state was "linked" to a different receptor), beyond those assumed in the base case.

The percent emissions reductions (and percent air quality improvement)

that could be made by each upwind state in 2014 at different cost per ton levels are shown in Figures IV.D–1 through IV.D–4, later. These figures show the percent reduction in SO_2 emissions as a function of cost (using the emissions at zero dollars per ton in 2014 as the baseline reference). A percentage reduction of zero means that emissions are not reduced from the levels that exist at the 2014 zero dollar per ton (base case) cost level. It is assumed that reductions in SO_2 emissions are linearly and directly proportional to downwind sulfate contributions. In other words, it is assumed that a specific percent reduction in SO_2 emissions would lead to the same percent reduction in air quality sulfate contribution from that upwind state. For example, if a state made a 50 percent reduction in SO_2 emissions, its sulfate contribution to any monitor downwind is assumed to be reduced by 50 percent.

EPA determines the cumulative air quality improvement that could be expected at a particular downwind receptor by multiplying each upwind state's percent reduction by its air quality contribution and summing the results for all upwind states. In EPA's air quality analysis of each downwind receptor, all air quality improvements are measured relative to baseline emissions and air quality contributions in 2012.

Figures IV.D–1 through IV.D–4 show that at increased costs, there are substantial increased emissions reductions. As explained previously, each decrease in emissions is assumed to lead to a corresponding improvement in downwind air quality. These changes apply to both the daily and annual $PM_{2.5}$ NAAQS. While the pattern differs from state to state, many states see noticeable decreases in sulfate contribution for costs of $500/ton or less. Reductions in downwind contribution level off, then many states start to see an additional decrease in contribution at higher costs (in general about $1,500/ton).

Figure IV.D-1 Percent Reduction in Downwind SO_2 Contribution as a Function of Cost in 2014 for DE, FL, KS, LA, MA, and NE.

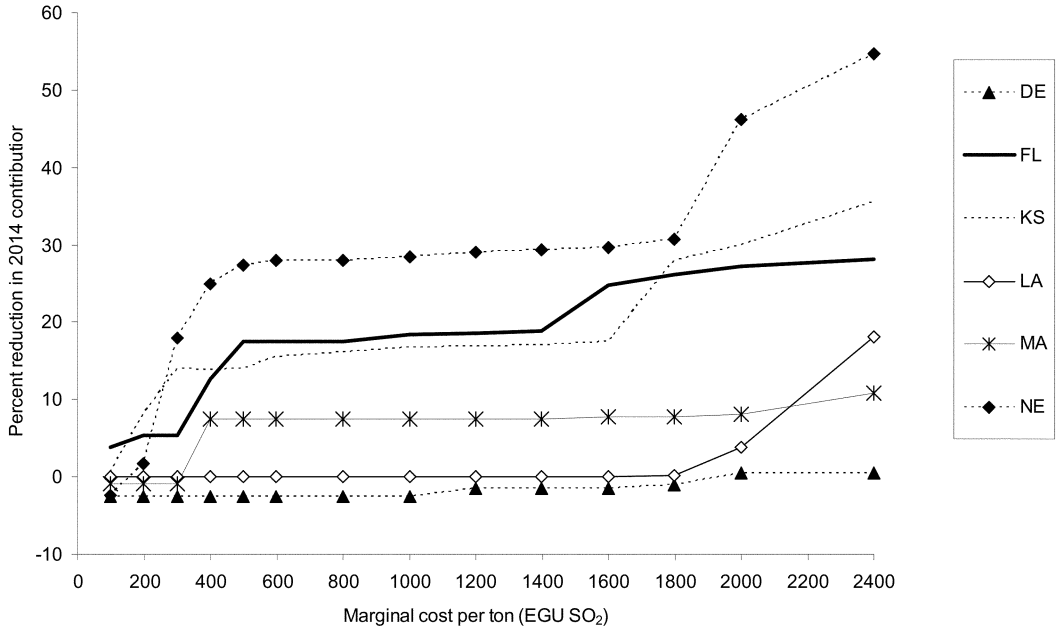


Figure IV.D-2 Percent Reduction in Downwind SO_2 Contribution as a Function of Cost in 2014 for AL, CT, MD, MN, NJ, and SC.

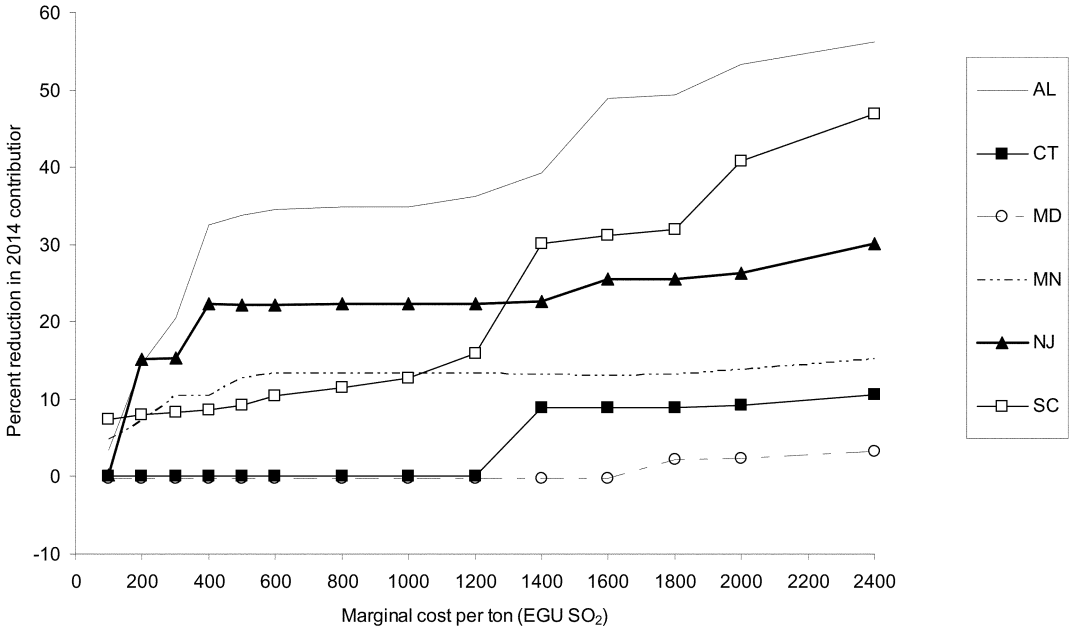


Figure IV.D-3 Percent Reduction in Downwind SO_2 Contribution as a Function of Cost in 2014 for IA, KY, NY, NC, OH, TN, and VA.

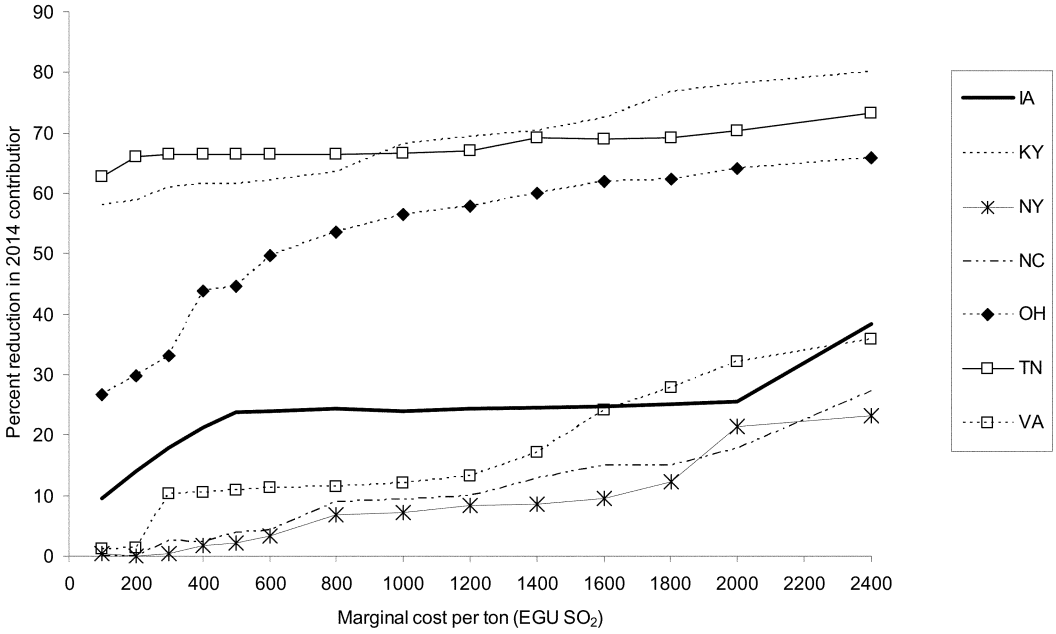
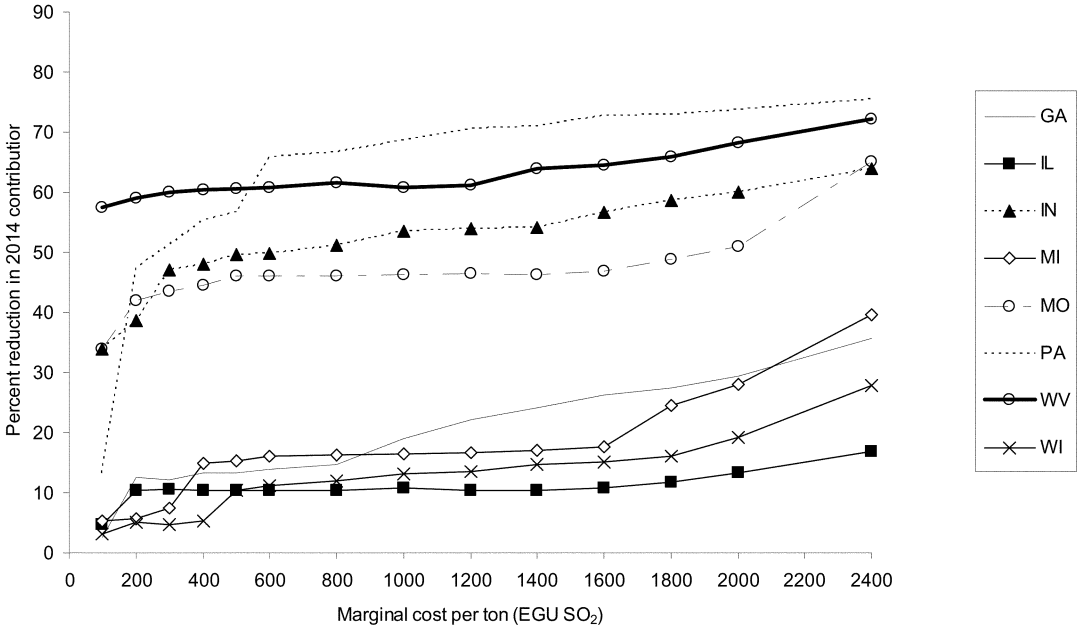


Figure IV.D-4 Percent reduction in downwind SO_2 contribution as a function of cost in 2014 for GA, IL, IN, MI, MO, PA, WV, and WI.



EPA also identified the overall air quality reductions projected by the air quality assessment tool at downwind nonattainment and maintenance receptor locations. As explained previously, the multi-factor assessment in step 3 analyzed the results from the downwind receptor analysis in step 2 for the annual and daily $PM_{2.5}$ standards. Tables IV.D–3 and IV.D–4 show the air quality improvements in 2014 from the emissions reductions projected to occur at various costs. Table IV.D–4 also shows the average decrease in ambient daily $PM_{2.5}$ for different sets of downwind sites for various reductions in SO_2.

TABLE IV.D–3—ESTIMATED NUMBER OF NONATTAINMENT AND/OR MAINTENANCE MONITOR SITES IN 2014 FOR ANNUAL $PM_{2.5}$

[As a function of SO_2 cost-per-ton levels]

Marginal cost per ton	2014	2014
	Number of remaining nonattainment monitor sites	Number of remaining nonattainment and maintenance monitor sites
>$0	12	19
>$100	3	6
>$200	2	3
>$300	2	3
>$400	1	2
>$500	1	2
>$600	1	1
>$800	1	1
>$1,000	1	1
>$1,200	1	1
>$1,400	1	1
>$1,600	1	1
>$1,800	0	1
>$2,000	0	1
>$2,400	0	1

TABLE IV.D–4—DAILY AIR QUALITY IMPACTS VS. SO_2 COST PER TON LEVELS IN 2014

Marginal SO_2 cost per ton	Number of remaining nonattainment and maintenance monitor sites	Air quality improvement (average μg/m∧3 Reduction) relative to 2014 base case (zero dollars/ton)		
		All sites in 2012 base	6 selected sites *	3 selected sites **
>$0	64	0.0	0.0	0.0
>$100	16	3.7	2.0	1.8
>$200	12	4.4	2.4	2.1
>$300	8	4.7	2.6	2.3
>$400	*6	5.0	2.9	2.6
>$500	6	5.1	3.0	2.6
>$600	6	5.3	3.1	2.8
>$800	6	5.4	3.3	2.9
>$1,000	6	5.6	3.4	3.0
>$1,200	6	5.7	3.4	3.0
>$1,400	6	5.8	3.5	3.1
>$1,600	5	6.0	3.6	3.2
>$1,800	4	6.2	3.7	3.3
>$2,000	**3	6.4	3.9	3.4
>$2,400	1	6.8	4.1	3.7

* The six sites are: Allegheny County, PA (2 sites); Baltimore County, MD; Wayne County, MI; Lake County, IN; Cook County, IL.
** The three sites are: Lake County, IN; Cook County, IL; Allegheny County, PA.

A number of conclusions can be drawn from Tables IV.D–3 and IV.D–4. Very low cost SO_2 reductions result in significant air quality benefits.[58] As explained previously, this is because there are significant reductions available from sources that operate existing scrubbers and, in a number of cases, use relatively low cost, lower sulfur coal. At the same time, in 2014 enough lead time exists for considerable emission reduction opportunities from new scrubber installations. Other programs are also achieving reductions (for example, some state rules and enforcement consent decrees require SO_2 and NO_X reductions in 2013 and 2014). The analysis also shows that higher cost reductions continue to provide downwind air quality improvements.

[58] Measured in terms of downwind area nonattainment and/or maintenance concerns being addressed. This is also true in terms of improvements in air concentrations of $PM_{2.5}$.

(4) Identifying Cost Thresholds

(a) Considerations for 2014

For $PM_{2.5}$, EPA considered three cost breakpoints for SO_2 and one for NO_X. First EPA looked at a point at which EGUs operated all installed controls, continued to burn coals with sulfur contents consistent with what they were burning in 2009, and operated any additional controls they are currently planning to install by 2014. For NO_X, this point is similar to the $500/ton cost. For SO_2, it is similar to the $300 to $400 cost. EPA believes this is an appropriate starting point, because if a state is "linked" to a downwind state (*i.e.*, if our air quality analysis showed it was contributing above the 1 percent threshold), EPA believes it is appropriate to prohibit that state from increasing its emissions which could worsen downwind air quality problems. EPA then considered what additional cost thresholds should be considered. For SO_2 EPA considered two breakpoints: (1) $2,000/ton SO_2 and (2) $2,400/ton SO_2. EPA's state-by-state cost modeling at that point indicates that scrubbers would be installed on units generating about 20 GW of electricity. Since slightly over 21 GWs of scrubbers were installed in both 2008 and 2009 (*see* EPA Analysis of Alternative SO_2 and NO_X Caps for Senator Carper—July 31, 2009 Appendix B, page 15), EPA believes that it is clearly possible for the power sector to install at least that quantity of scrubbers by 2014. The $2,400/ton SO_2 breakpoint represents the point where analysis from the air quality assessment tool projects that both nonattainment and maintenance concerns would be fully addressed in all areas, except for Allegheny County, Pennsylvania, when considering reductions from only states that contribute more than 1 percent.[59] As is explained later in this section, EPA believes that the monitor in Allegheny County that remains in nonattainment is in an area where the air quality problem is primarily local. Since EPA's analysis suggests that the only remaining nonattainment problem is primarily local, EPA did not consider higher cost thresholds.

EPA did not consider additional cost thresholds for NO_X beyond $500/ton because there are minimal additional NO_X reductions until one considers cost levels higher than $2,400/ton, and SO_2 reductions are generally more effective than NO_X reductions at reducing $PM_{2.5}$. EPA did not consider lower cost thresholds than $2,000/ton for SO_2 because: There are clearly continued air quality benefits at higher costs (as evidenced by increases in average air quality improvements in downwind sites); there is very little change in the number of downwind nonattainment and/or maintenance sites, indicating that the number of upwind states contributing would not be expected to change much; and costs of up to $2,000/ton of SO_2 are reasonable in comparison to other existing regulations.

First EPA assessed $2,000/ton. Reductions at $2,000/ton would improve air quality at several locations with nonattainment and/or maintenance problems. We also believe that, as explained in the introduction to this section, it is reasonable to require a substantial level of control of upwind state emissions that significantly contribute to nonattainment or maintenance problems in another state. We believe that $2,000/ton is reasonable for SO_2 considering that this cost per ton level is based on EGU control technologies that are proven and already widely deployed. Furthermore, compared to other control measures that address SO_2, this cost per ton level is relatively low. A survey of the control options that EPA examined in the $PM_{2.5}$ RIA shows that non-EGU SO_2 reduction opportunities cost from $2,270/ton to over $16,000/ton.

While analysis with the air quality assessment tool shows that a site in Allegheny County, Pennsylvania would be in nonattainment and two other sites—Lake County, Indiana and Cook County, Illinois—would have maintenance problems, if we assume reductions at $2,000/ton and additional reductions made by states because of their contribution to other downwind sites that do not contribute to these three problem areas, the maintenance problems in Lake County, Indiana and Cook County, Illinois would be resolved and only Allegheny County, Pennsylvania, would continue to have a nonattainment/maintenance problem. Because reductions at $2,000/ton continue to have significant air quality benefit for downwind sites with nonattainment and/or maintenance problems, it has been demonstrated historically that the amount of control equipment that is projected to be needed at $2,000/ton could be installed in the timeframe required and these costs are reasonable when compared to other options to reduce SO_2. Therefore, EPA believes that requiring a cost threshold of at least $2,000/ton would be appropriate for determining significant contribution.

Because our analysis shows that one area (Allegheny County, Pennsylvania) would have continuing nonattainment and maintenance problems, EPA continued to perform its multi-factor assessment for the higher $2,400/ton breakpoint to see if any additional emissions should also be considered significant. For this receptor monitor, EPA considered the local circumstances in the Liberty-Clairton area in Allegheny County that were leading to continued nonattainment. It is well-established that, in addition to being impacted by regional sources, the Liberty-Clairton area is significantly affected by a large increment of local emissions from a sizable coke production facility and other nearby sources. (*See http://www.epa.gov/pmdesignations/2006standards/final/TSD/tsd_4.0_4.3_4.3.3_r03_PA_2.pdf*). High concentrations of organic carbon indicate the unique local problem for this location.

Because the remaining $PM_{2.5}$ problem is more local in nature than the problem at other receptors, EPA does not believe that it is appropriate to establish a higher cost threshold solely for states that are "linked" to this monitor.

(b) Amount of Reductions That Could Be Achieved by 2012

After determining that the amount of emissions that could be reduced for $2,000/ton in 2014 is an appropriate quantification of a state's significant contribution, EPA considered whether any of these emissions reductions could be achieved prior to 2014. For the reasons that follow, EPA concluded that significant reductions could be achieved by 2012 and that it is important to require all such reductions by 2012 to ensure that they are achieved as expeditiously as practicable. While EPA believes that it is not possible to require the installation of post-combustion SO_2 controls (scrubbers) or post-combustion NO_X controls (SCRs) before 2014 (because it takes about 27 months to install a scrubber and 21 months to install an SCR), EPA believes that there are significant reductions that can occur earlier. For SO_2, reductions from operating existing scrubbers up to their design removal efficiencies and from the use of lower sulfur coals are possible by 2012. For NO_X, reductions from operating existing SCRs on a year-round basis and up to their design removal efficiencies and the installation of limited amounts of low NO_X burners are possible by 2012. For this reason, EPA believes it is appropriate to require these emissions to be removed in 2012,

[59] When considering all reductions made, including those by states that contribute less than 1 percent, the air quality assessment tool projects that both nonattainment and maintenance will be fully addressed in all areas except for Allegheny County, PA at $2,000/ton.

consistent with the Act's requirement that downwind states attain the NAAQS as expeditiously as practicable. Section IV.E explains how these 2012 emissions reductions requirements are defined.

(c) Off-Ramp for States That Eliminate Their Significant Contribution for Less Than $2,000/Ton

Table IV.D.4, previously, shows that for large numbers of monitoring sites where there are nonattainment and or maintenance problems, those problems are fully resolved before all states achieve all of the emissions reductions that could be achieved at or below $2,000/ton. EPA used the air quality assessment tool to analyze the impact of requiring all states linked to the downwind state site with an air quality problem, as well as the downwind state, to reduce emissions consistent with the levels discussed for 2012 in section IV.D.2.a(2), previously. The air quality assessment tool shows that those 2012 reductions will resolve the nonattainment and maintenance problems for all of the areas to which the following states are linked: Alabama, Connecticut, Delaware, the District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey and South Carolina (referred to as group 2 states). EPA also assessed whether, in 2014, the combination of this level of reduction from the group 2 states and the remaining states (referred to as group 1 states) continued to result in all downwind areas—except for Allegheny County, Pennsylvania—fully addressing their nonattainment and or/maintenance problems, and determined that it did.

The states in group 1 and group 2 are rationally grouped considering air quality and cost. EPA proposes that it would not be appropriate to assign the same cost per ton to group 2 and group 1 states because a significantly lower cost per ton was sufficient to resolve air quality problems at all downwind receptors linked to the group 2 states. Although states are linked to different sets of downwind receptors, our analysis indicated that the cost per ton needed to resolve downwind air quality problems varied only to a limited extent among states within group 1 and among states within group 2. The cost per ton did vary greatly between the group 1 and group 2 states. Limitations on the accuracy of our cost and air quality analyses, and the ruling in the *Michigan* decision accepting EPA's prior use of a uniform cost approach, support the decision to use uniform costs for a group of states.

(d) Proposed Cost Thresholds for $PM_{2.5}$

Summary of methodology. In summary, EPA determined that SO_2 emissions that could be reduced for $2,000/ton in 2014 should be considered a state's significant contribution, unless EPA determined that a lesser reduction would fully resolve the nonattainment and/or maintenance problem for all the downwind monitoring sites to which a particular state might be linked. For these "group 2 states" EPA is determining that a lesser reduction of SO_2, based on the amount of SO_2 reductions that can be reasonably achieved by 2012 is appropriate. EPA also determined that all states linked to downwind $PM_{2.5}$ nonattainment and maintenance problems should be required to achieve those emissions reductions that can be reasonably achieved by 2012. Finally, EPA determined that all states linked to downwind $PM_{2.5}$ nonattainment (*see* Table IV.D–5) and maintenance problems should, by 2012, remove all NO_X emissions that can be reduced for $500/ton in 2012.

TABLE IV.D–5—STATES COVERED FOR SO_2 GROUP 1, SO_2 GROUP 2, AND NO_X ANNUAL

States covered	SO_2 group 1	SO_2 group 2	NO_X annual
Alabama		X	X
Connecticut		X	X
Delaware		X	X
District of Columbia		X	X
Florida		X	X
Georgia	X		X
Illinois	X		X
Indiana	X		X
Iowa	X		X
Kansas		X	X
Kentucky	X		X
Louisiana		X	X
Maryland		X	X
Massachusetts		X	X
Michigan	X		X
Minnesota		X	X
Missouri	X		X
Nebraska		X	X
New Jersey		X	X
New York	X		X
North Carolina	X		X
Ohio	X		X
Pennsylvania	X		X
South Carolina		X	X
Tennessee	X		X
Virginia	X		X
West Virginia	X		X
Wisconsin	X		X
Totals	15	13	28

After completing the process to propose appropriate state-by-state cost thresholds, EPA used these thresholds to develop the specific state-by-state budgets. This step in the process is fully described in section IV.E.

(e) Request for Comment on Issues Related to EPA's Modeling Methods

EPA believes that the methodology described previously is a sound and analytically efficient approach to addressing the requirements of 110(a)(2)(D)(i)(I) for the $PM_{2.5}$ standards. While it would be possible for EPA to add additional analytical steps to the methodology, and such analyses would provide more information, EPA believes that the methodology selected strikes an appropriate balance between the competing requirements of comprehensive analysis and timely action. EPA believes that the technical analysis completed provides a sound basis for action. EPA also seeks to avoid burdensome technical analyses which could prevent EPA from fulfilling our obligation to the Court to act in a timely way. In this section, EPA generally requests comment on issues related to its efforts to strike an appropriate balance. EPA identifies several areas of recognized limitations on our methodology, and requests comments both on the implications of these limitations and on possible options for addressing these limitations without unduly delaying necessary action.

(f) Use of Air Quality Assessment Tool; Results of More Detailed Air Quality Modeling Used To Evaluate the Tool

As discussed previously, EPA uses a simplified air quality assessment tool, rather than actual air quality modeling, to identify air quality impacts of the options considered. This assessment tool enables efficient evaluation of multiple options quickly. We did, however, conduct more refined air quality modeling of the select emissions budgets and this more detailed modeling serves as a check on the appropriateness of the method. This check confirmed the directional conclusions of the air quality assessment tool and largely confirmed the more detailed results of the air quality assessment tool, but raised several issues on which EPA is requesting comment.

For the annual $PM_{2.5}$ standard, the air quality assessment tool projected that, after implementation of the proposed FIPs, only one area (Allegheny County, PA) would have a continuing NAAQS air quality problem under the maintenance criteria. The results of the refined air quality modeling are very similar. This modeling projects similar annual $PM_{2.5}$ reductions in downwind states and projects that Allegheny County, PA would remain in nonattainment and that Birmingham, AL would exceed the threshold for "maintenance" by a slight amount (less than 0.1 ug/m^3). Given the unique local nature of the Allegheny County, PA receptor (*see* discussion previously), EPA does not believe that the fact that the air quality assessment tool projects the area to have only a maintenance problem, while the refined air quality modeling suggests that the area would remain in nonattainment, raises any serious issues about the conclusions regarding significant contribution to nonattainment and interference with maintenance with the annual $PM_{2.5}$ standard. Similarly, because the refined air quality modeling projects that Birmingham, AL will exceed the maintenance criteria by only an extremely slight amount and because reductions from nearby point sources will reduce local emissions in the area, EPA does not believe the refined air quality modeling demonstrates that upwind reductions beyond those in the proposed FIPs are required to address significant contribution and interference with maintenance of the annual $PM_{2.5}$ NAAQS in Birmingham. For these reasons, EPA does not believe that the more refined air quality modeling for the annual $PM_{2.5}$ standard changes any of EPA's conclusions with respect to reductions required to eliminate significant contribution and interference with maintenance with respect to this standard. EPA is, however, taking comment on whether Florida, the one group 2 state that was identified as linked to Birmingham, should be moved from group 2 to group 1. EPA notes that no group 2 states are linked to Allegheny County, PA.

For the 24-hour $PM_{2.5}$ standard, the simplified air quality assessment tool results suggest that under EPA's proposed FIPs, only one problem site, Allegheny County, PA, would remain. In contrast, the more refined CAMx air quality modeling results show a greater 24-hour $PM_{2.5}$ problem, with 10 nonattainment and 4 maintenance areas. As described later, EPA is evaluating the impact of this refined air quality modeling on the methodology used and the conclusions it has reached regarding significant contribution and interference with maintenance with regard to the 24-hour $PM_{2.5}$ NAAQS.

EPA has completed some preliminary analysis of the difference between the air quality assessment tool and CAMx results (*see* the TSDs "Analysis to Quantify Significant Contribution" and "Air Quality Modeling"). This analysis suggests that the main difference is that in the winter months, the CAMx modeling shows smaller air quality reductions compared to the assessment tool. This is because the CAMx air quality modeling more accurately reflects the complex nature of the winter portion of the 24-hour $PM_{2.5}$ problem. Unlike summer days, for which sulfate is the dominant contributor to $PM_{2.5}$, sulfate concentrations are typically a lesser contributor to the overall $PM_{2.5}$ concentrations on winter days. Moreover, for winter days, reductions in this already reduced amount of sulfate appear to be less responsive to reductions in SO_2 emissions than for summer days. That is, while for the summer a 50 percent reduction in SO_2 emissions would likely yield a nearly 50 percent reduction in sulfate concentrations, in the winter such a reduction in SO_2 would reduce sulfate by less than 50 percent. Thus, EPA believes that more study of the winter portion of the problem is warranted to address the issues raised by the CAMx modeling. EPA believes it is important to understand the degree to which these winter exceedances are transport-related or locally generated, and the degree to which upwind states' emissions of NO_X, SO_2, and other transported pollutants are significantly contributing to these winter exceedances.

Because the CAMx results indicate additional nonattainment and maintenance areas compared to the air quality assessment tool, EPA requests comment on whether the $2,000/ton cost cutoff for SO_2 resulting from the assessment tool should be raised to a higher cost cutoff. While the CAMx results may suggest that it would be appropriate to use a cutoff greater than $2,000/ton, the results do not suggest that the cutoff could be less than $2,000/ton. Instead, the results confirm the importance of achieving, at a minimum, all reductions available at the $2,000/ton cost threshold.

Additionally, EPA is requesting comment on whether some group 2 states should be moved to group 1. These group 2 states are: Connecticut, Kansas, Maryland, Massachusetts, Minnesota, Nebraska, and New Jersey. These states were all placed in group two because the air quality assessment tool indicates that the 2012 reductions will resolve the nonattainment or maintenance problems at all areas to which they are linked. However, for these states, the CAMx modeling indicates that one or more of the states to which they are linked will have continuing nonattainment and

maintenance problems after the implementation of the 2012 reductions.

EPA also notes that during the winter, $PM_{2.5}$ contains a larger nitrate component than in summer months. One reason for this is that some nitrates that are particles in cooler weather volatize and exist as gases during warmer weather. Given this larger contribution from nitrates in the winter, EPA is also taking comment on whether there should be a higher cost threshold for annual nitrogen oxides. This may be appropriate for states that have been identified as contributing significantly to sites that the CAMx air quality modeling continues to show as having a residual nonattainment and/or maintenance concern in 2014.

Finally, EPA requests comment on how and whether EPA should incorporate the use of detailed models such as CAMx into our methodology for significant contribution and interference with maintenance.

(g) Possibility for Emissions Increases in Noncontributing States

EPA also evaluated whether the proposed rule could cause changes in operation of electric generating units in states not regulated under the proposal (that is states not listed in table IV.D–5). Specifically, EPA evaluated whether such changes could lead to increases in emissions in those states, potentially affecting whether they would exceed the 1 percent contribution thresholds used to identify linkages between upwind and downwind states. (*See* sections IV.B and IV.C previously for more discussion of the 1 percent thresholds). Such changes are possible in part because of the interconnected nature of the country's energy system (including both the electricity grid and coal and natural gas supplies). In addition, our models project that the rule affects the cost of coal (generally lowering the cost of higher sulfur coals and raising the cost of lower sulfur coals). If these price effects took place and if the rule is finalized as proposed, sources in states not covered by the proposed rule might choose to use higher sulfur coals. Increased use of such coals could thus increase SO_2 emissions in those states. EPA's modeling confirms this, projecting that, after the proposed rule is implemented in states regulated for SO_2, emissions in some states not covered by the proposed rule would increase (i.e., their emissions are greater in the control case modeling than in the base case modeling). As shown in table IV.D–6, Arkansas, Mississippi, North Dakota, South Dakota, and Texas all exhibit 2012 SO_2 emissions increases over the base case and above 5,000 tons.[60] For reference, we also include the statewide 2012 base case emissions from all sources within the state.

TABLE IV.D–6—UNREGULATED STATES WITH MORE THAN 5,000 TONS OF PROJECTED SO_2 INCREASES UNDER THE PROPOSED TRANSPORT RULE

State	2012 SO_2 increase from base case (thousand tons)	2012 SO_2 base case emissions from all sources (thousand tons)
Arkansas	32	127
Mississippi	18	80
North Dakota	11	94
South Dakota	6	26
Texas	136	640

Further analysis with the air quality assessment tool indicates that these projected increases in the Texas SO_2 emissions would increase Texas's contribution to an amount that would exceed the 0.15 $\mu g/m^3$ threshold for annual $PM_{2.5}$. For this reason, EPA takes comment on whether Texas should be included in the program as a group 2 state.

(h) Providing Downwind States Full Relief From Upwind Emissions

EPA takes very seriously its responsibility to ensure that upwind reductions are made in a timely way so that downwind states can meet their attainment obligations.

EPA recognizes, as discussed previously, that while this proposal fully addresses the annual $PM_{2.5}$ standard, it may not fully address the 24-hour $PM_{2.5}$ standard. Where this may be the case, as explained previously, EPA's air quality modeling shows that the remaining component of non-attainment is almost entirely occurring in the winter months. Also as noted previously the atmospheric chemistry related to secondary particle formation, and the relative importance of particle species such as sulfate and nitrate, is quite different between summer and winter. Because of this, EPA is moving ahead with further efforts, before the final rule is published, to determine the extent to which this winter problem is caused by emissions transported from upwind states and, if this is the case, to identify the total amount of emissions that represents significant contribution and interference with maintenance. To the extent possible, EPA plans to finalize a rule that fully defines this amount.

Based on the information that EPA currently has, EPA believes there are a number of possible outcomes of this further study. Possible outcomes include:

(1) Identification of the additional amount of SO_2 emissions reductions needed to eliminate significant contribution and interference with maintenance from upwind states contributing to the residual 24-hour $PM_{2.5}$ problem sites.

(2) Identification of the additional amount of NO_X emissions reductions needed to eliminate significant contribution and interference with maintenance from upwind states contributing to the residual 24-hour $PM_{2.5}$ problem sites.

(3) Identification of another pollutant that should be considered part of significant contribution and interference with maintenance for states that

[60] While Colorado is also a state that may see projected increases in emissions, it was not within the domain the EPA analyzed.

contribute to the residual 24-hour $PM_{2.5}$ problem sites.

(4) Determination that the reductions proposed in today's rulemaking would fully address significant contribution and interference with maintenance at these sites.

If EPA determines that more SO_2 emissions should be considered part of this amount based on the analysis performed for today's proposal, EPA believes that the next set of emissions that can be reduced above the $2,000/ton threshold would likely still come from the power sector. If EPA determines that more SO_2 emissions reductions are required or that the amount of emissions of SO_2 and NO_X that it has proposed as significantly contributing to nonattainment are the appropriate amounts to address this winter portion of the problem, EPA intends to supplement today's proposal and finalize a rule that would fully addresses emissions that significantly contribute to or interfere with maintenance of the 2006 daily $PM_{2.5}$ standard.

To the extent that EPA determines that more NO_X reductions are needed or that reductions of another pollutant are needed, EPA believes that we could provide the greatest assistance to states in addressing transport by finalizing this rule quickly and promulgating a separate rule to achieve any necessary additional NO_X reductions. This is because those emissions reductions would likely involve placing reduction requirements on sources other than EGUs and that additional approaches would need to be addressed. EPA believes that developing supplemental information to address these sources and concepts would substantially delay publication of a final rule, beyond the anticipated publication of spring 2011.

EPA plans to move forward aggressively in the event that these further reductions are needed. We do not, however, intend to delay the reductions in this proposed rule because those reductions have a substantial impact on states' abilities to attain the NAAQS in the required time period and have large health benefits.

b. Specific Application to Ozone

This section discusses, for the 1997 ozone standards, how EPA applies its multi-step methodology for defining each state's significant contribution. For some aspects of the methodology, further work is needed to complete the methodology for ozone and this further work will be completed in a separate proposal.

(1) Years for Quantifying Significant Contribution

In this subsection, we discuss how EPA identifies for ozone the years to analyze for eliminating significant contribution. Similar to the previous discussion for $PM_{2.5}$, EPA believes that the selection of the year for eliminating significant contribution is informed by the attainment deadline and by the Act's requirement to attain the NAAQS "as expeditiously as practicable."

As noted earlier, the 2012 ozone season is the last ozone season before the 2013 attainment deadline for ozone areas classified as "serious" for the 1997 ozone air quality standards. Thus, for any states "linked" to "serious area" locations for which 2012 is the latest ozone season prior to their attainment deadline, EPA believes that 2012 is the appropriate year for eliminating significant contribution, to the extent that purpose can be achieved given the short time period. Because this proposed rule would not be finalized until 2011, the year 2012 also represents the earliest time by which emissions reductions could be achieved, which is consistent with statutory provisions calling for downwind states to achieve attainment "as expeditiously as practicable." This also is relevant for certain other areas with lower ozone classifications that are projected in our analysis to have continuing air quality problems and to be affected by transported pollution from certain upwind states in amounts greater than the 1 percent threshold.[61]

EPA is concerned that the timing of this rule presents difficult challenges in eliminating significant contribution and interference with maintenance with regard to the 1997 ozone NAAQS by the attainment date. For states with a 2012 (or earlier) attainment date for which we project continuing ozone problems, we are concerned that strict adherence to a 2012 date for reductions could be viewed as an artificial constraint on our ability to require appropriate reductions. EPA believes that the current situation for ozone, involving a transport rulemaking within months of the attainment date (and in a number of cases, after the current attainment date) is a unique situation created by the Court's remand of the CAIR. Under normal circumstances adhering to the CAA schedule for addressing transport within 3 years after a NAAQS is promulgated, transport requirements would be in place years before the attainment date. For purposes of our analysis of ozone for areas with a 2012 attainment date, EPA proposes that we should not be constrained to only considering those reductions that are possible by 2012.

Another reason that it would be inappropriate to limit upwind state responsibility based on the downwind area's current attainment date is that the statute contains provisions for extension of attainment dates. To the extent that downwind states have continuing ozone air quality problems after 2012, the Act requires that they be reclassified, which allows the downwind area to qualify for a later attainment date that is as expeditious as practicable but no later than 2019 (2018 emissions year).[62] In addition, two 1-year attainment date extensions can be granted if an area comes close to attaining, based on specific criteria. In addition, history shows many examples of states not meeting air quality standards by their attainment deadlines, often due in part to interstate pollution transport. Even if a downwind area attains on time, further upwind reductions may be important to assure continued maintenance of the standard.

If in determining upwind state reduction responsibilities EPA were to automatically assume that downwind states will attain on time despite pollution transport, this assumption would have the effect of absolving the upwind state of responsibility for any reductions in pollution transport that could not be achieved by the downwind area's current attainment date. EPA does not believe this would be appropriate. This would transfer emissions control responsibility from the upwind state to the downwind state in any case when the area did not attain by its current attainment date, and could delay for years the date when the public would breathe air that meets health-based standards.

Accordingly, for all the reasons discussed previously, we address both 2012 and 2014 in our analysis, and we do not believe that examining 2012 only would be appropriate. EPA has chosen to examine 2014 air quality results because, based on a conservative estimate, 2014 is the earliest year for which significantly more stringent NO_X limits (e.g., reflecting SCR) could conceivably be considered in a swift, subsequent rulemaking.

One area in the eastern half of the U.S. covered by this proposal, Houston,

[61] This is possible where: (1) Latest monitoring data indicate attainment of the 1997 ozone standard, (2) the area is operating under one-year extensions of their 2009 deadline, or (3) EPA has not made a formal finding of failure to attain.

[62] In the case of $PM_{2.5}$, under subpart I, areas can qualify for an extension beyond 5 years, to as many as 10 years, based on certain statutory criteria.

is classified as "severe." For Houston, it is relevant to consider both that (1) the latest permissible attainment date for severe areas is June 2019, which would require emissions reductions by the 2018 ozone season, and (2) the state implementation plan must provide for attainment as expeditiously as practicable. In light of this, EPA may select a year between 2012 and 2018 that is as expeditious as practicable as the appropriate year for eliminating significant contribution. Because, as explained later, further analysis is needed to quantify any additional reductions necessary to eliminate significant contribution to Houston, EPA requests comment on which year we should select within this 2012 to 2018 time period for this analysis.

(2) Step 1. Emissions Reductions Cost Curves for EGU Ozone Season NO_X

Using IPM, EPA developed cost curves for 2012 for ozone season NO_X, showing the ozone season (May–September) NO_X reductions available in 2012 at different cost increments. Specifically, EPA developed cost curves that show reductions available in 2012 from EGUs at various costs (in 2006 $) up to $5,000/ton. These EGU cost curves are presented in Table IV.D–7. Generally, projected emissions reductions for 2012 are modest because, by 2012, it is not feasible to install add-on equipment. Some highly effective and widely employed NO_X control technologies such as SCR could not be planned and installed in significant numbers within a 1-year time period (i.e., because a single SCR unit on average takes 21 months to install,[63] SCR-based limits in 2012, if feasible at all, would require an unacceptably steep cost premium).

For some states (particularly those which are not regulated by the NO_X SIP Call) EPA identified potential reductions from the installation of some combustion controls/low NO_X burners and the use of existing SCR units that, in the absence of CAIR, would not be required to operate. These reductions are available at approximately $500/ton in 2012. There were very few emissions reductions available below this cost.

TABLE IV.D–7—2012 OZONE-SEASON NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE AT VARIOUS COSTS (2006$) PER TON (THOUSAND TONS)

Marginal cost per ton	$0	$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$5,000
Alabama	30	30	30	30	30	30	30	29	29
Arkansas	21	11	11	11	11	11	11	11	11
Connecticut	3	3	3	3	3	3	3	3	3
Delaware	2	2	2	2	2	2	2	2	2
Florida	101	74	60	59	59	59	59	58	57
Georgia	35	33	33	33	33	33	33	33	33
Illinois	24	24	25	25	25	25	25	25	25
Indiana	51	50	49	48	47	47	47	46	46
Kansas	31	15	15	15	14	14	14	14	14
Kentucky	31	31	30	30	30	30	29	29	29
Louisiana	22	17	17	17	17	17	17	17	17
Maryland	14	14	14	14	14	14	14	14	14
Michigan	30	30	30	30	30	30	29	28	28
Mississippi	17	8	8	8	8	8	8	8	8
New Jersey	7	7	7	7	7	7	7	7	7
New York	16	16	16	16	16	16	16	16	16
North Carolina	27	27	27	27	27	27	27	27	27
Ohio	42	41	41	41	41	42	42	42	42
Oklahoma	43	27	27	27	27	26	26	26	26
Pennsylvania	51	51	51	51	50	50	50	50	48
South Carolina	16	16	16	15	15	15	15	15	15
Tennessee	12	12	12	12	12	12	12	12	12
Texas	79	67	67	67	7	66	66	66	66
Virginia	18	18	18	18	18	18	17	17	17
West Virginia	24	24	23	23	22	23	22	22	18
Total	746	648	632	628	625	622	620	618	609

As discussed in section IV.D.3 later, little or no ozone season NO_X reductions are available for non-EGU sources from control measures costing (at or below) $500/ton. The ozone season NO_X cost curves in Table IV.D–7 include EGU reductions only. EPA believes that for costs at or below $500/ton, these curves include all available reductions (because only EGUs have substantial reduction opportunities at or below $500/ton), but for greater costs the curves do not include all available reductions as they do not include non-EGU reductions.

For this reason, we are not addressing in this proposal whether cost per ton levels higher than $500/ton are justified for some upwind states and downwind receptors for ozone purposes. However, we are presenting the information we have on potential EGU reductions at higher cost levels for informational purposes. EPA intends to develop similar emissions reductions and cost information for sources other than EGUs and, in a future rulemaking, to consider whether or not reductions at a higher cost per ton are warranted for EGUs and other source categories.

EPA developed EGU emissions reductions cost curves for 2014 as well as 2012. EPA believes it is useful to understand and display emissions reductions capabilities for 2014, the first year for which further emissions reductions could be achieved through the installation of add-on controls such as SCR. These 2014 ozone season

[63] Estimate from EPA report, "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-Pollutant Strategies," CAIR docket no. OAR–2003–0053–0106).

emissions cost curves are presented in Table IV.D–8. The 2014 results have similarities to the 2012 results in that there is an initial drop in emissions when controls are applied at costs of $500 per ton, which represents the use of SCR units in states that would not be mandated to so. Also similar to the 2012 results, relatively few reductions are seen between $500/ton and $2,500/ton. In contrast to the 2012 results, add-on controls become feasible in 2014 at costs between $2,500/ton and $5,000/ton and more EGU emissions reductions are possible at those cost levels.

TABLE IV.D–8—2014 OZONE-SEASON NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE AT VARIOUS COSTS (2006$) PER TON (THOUSAND TONS)

Marginal cost per ton	$0	$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$5,000
Alabama	27	27	27	27	27	27	27	26	26
Arkansas	22	12	12	12	12	11	11	11	12
Connecticut	3	3	3	3	3	3	3	3	3
Delaware	2	3	3	3	3	3	3	3	3
Florida	95	72	58	57	57	56	53	43	37
Georgia	22	20	20	20	20	20	20	20	19
Illinois	24	24	24	24	24	24	24	24	24
Indiana	49	48	48	47	47	47	46	44	43
Kansas	35	16	16	16	16	16	16	15	15
Kentucky	30	30	30	29	29	29	29	29	28
Louisiana	21	17	17	17	17	17	17	13	13
Maryland	15	15	15	15	15	15	15	15	15
Michigan	30	30	30	30	29	29	29	29	28
Mississippi	17	8	8	8	8	8	8	8	7
New Jersey	10	10	10	10	10	10	10	10	9
New York	17	17	17	16	16	16	15	15	15
North Carolina	27	27	27	27	27	27	27	27	26
Ohio	45	44	43	43	42	42	42	41	38
Oklahoma	39	24	24	24	24	23	23	23	20
Pennsylvania	53	53	52	52	52	52	52	52	41
South Carolina	16	16	15	15	15	15	15	15	15
Tennessee	12	12	12	12	12	12	12	12	12
Texas	80	69	68	68	67	66	66	66	66
Virginia	16	16	16	16	16	16	16	16	15
West Virginia	24	24	24	21	22	20	20	19	19
Total	732	639	621	614	610	604	598	579	547

(3) Step 2. Air Quality Assessment of Potential 2012 Emissions Reductions

EPA uses an air quality assessment tool for ozone to assess the effect of NO_X reductions on downwind ozone concentrations. This air quality assessment tool assumes a linear relationship between the reduction in an upwind state's ozone season NO_X reductions and the reduction in that state's contribution to downwind ozone levels. For example, if a given upwind state reduced its ozone season NO_X emissions by 20 percent, the air quality assessment tool estimates that there would also be a 20 percent reduction in the state's contribution to downwind ozone. Using this assessment tool, EPA projected the air quality impact of the emissions reductions at the $500/ton NO_X level, the level for which we have complete estimates of potential emissions reductions. The assessment shows significant improvements in 2012 at downwind air quality locations, as evidenced by a reduction in the number of nonattainment and maintenance locations. EPA presents these 2012 ozone season results in Table IV.D–9.

EPA also includes in Table IV.D–9 results for 2014 before and after the imposition of currently installed controls (that is, for the base case or zero dollars per ton, and for the case for which all controls are applied up to $500/ton). Because there are substantial reductions in ozone season NO_X from mobile source fleet turnover between 2012 and 2014, there are correspondingly substantial improvements in ozone in the base case, even in the absence of additional EGU or other stationary source controls. Additionally, in this 2014 analysis, when these mobile source reductions are combined with EGU reductions at $500/ton, the simplified air quality assessment tool projects that almost all sites, with the exception of Houston, TX (nonattainment) and Baton Rouge, LA (maintenance), have resolved their ozone problems.

TABLE IV.D–9—ESTIMATED NUMBER OF REMAINING NONATTAINMENT OR NONATTAINMENT AND MAINTENANCE MONITOR SITES IN 2012 AND 2014 AS A FUNCTION OF OZONE-SEASON NO_X COST PER TON LEVELS

	2012	2012	2014	2014
Marginal Cost per Ton	Number of Remaining Nonattainment Monitor Sites	Number of Remaining Nonattainment and Maintenance Monitor Sites	Number of Remaining Nonattainment Monitor Sites	Number of Remaining Nonattainment and Maintenance Monitor sites
>$0	11	25	4 (all in Houston, TX)	7 (Houston, TX; Baton Rouge, LA).
>$500	10	19	1	7.

(4) Step 3. Selection of Cost Thresholds, Taking Into Account Cost and Air Quality Considerations

Using the multi-factor cost and air quality methodology described in section IV.D.1, EPA identifies, for a number of states, the 2012 emissions reductions that eliminate the significant contribution to nonattainment of the 1997 ozone NAAQS and interference with maintenance to the 1997 ozone NAAQS.

(a) Cost Considerations

As discussed previously, $500/ton represents the cost level for which EPA has complete information across source categories and represents the level for which significant emissions reductions are available in 2012. Large additional reductions in 2012 cannot be achieved given the insufficient amount of time for sources to install controls. Compared to NO_X reduction levels determined to be highly cost effective in both the NO_X SIP Call and the CAIR, $500/ton is a very low cost for requiring ozone season NO_X reductions, and reductions at this level show measurable downwind air quality benefit. EPA believes that $500/ton continues to be an extremely cost effective level for NO_X control relative to benchmarks provided by the cost per ton of NO_X reductions in existing rules or available from technologies in various sectors, and the $500/ton level is based on proven and widely deployed technology.

Considering the upwind-downwind state policy considerations discussed previously, $500/ton NO_X clearly is not an unreasonable cost level of control for all upwind states that contribute more than threshold amounts to ozone air quality problems in downwind states.

EPA believes that on purely reasonableness or highly cost effective grounds, a value considerably greater than $500/ton could be justified. EPA notes that the $2,000/ton threshold for highly cost effective ozone season NO_X controls for the NO_X SIP Call was calculated based on 1990 dollars. If this threshold were updated based on a more recent year, such as the 2006 year used for recent EPA RIA documents, the $2,000/ton threshold would become approximately $3,200 per ton. As a result, EPA believes that controlling to at least this level should be considered, unless air quality considerations suggest an "off-ramp" at lower cost levels.

(b) Air Quality Considerations

Using the air quality assessment tool, EPA determined that emissions reductions from ozone season NO_X controls at $500/ton would have a significant reduction in nonattainment and maintenance receptors in 2012. Accordingly, EPA believes that requiring the reductions that can be achieved at $500/ton are justified based upon the 2012 air quality results.

EPA proposes, as discussed previously, that EPA is not artificially constrained in considering reductions beyond 2012 and that it is relevant to address possible air quality impacts of additional emissions reductions that could be achieved by 2014, the first year for significant additional controls. At the same time, EPA proposes that while 2014 is a relevant year to consider, it is also relevant to consider the nature of the air quality problem in 2014 even in the absence of further transport controls that could be achieved by that date. Taking all of these 2014 considerations into account, the air quality assessment tool results show that in 2014 ozone problems remain only for locations in Houston and Baton Rouge. Thus, EPA believes that additional post-2012 controls, beyond the $500/ton reductions that are justified based on 2012, are possibly warranted for states that are linked to Houston and Baton Rouge. (See also discussion later on the issue regarding New York City raised by air quality modeling results.)

(c) Proposed Cost Threshold for Ozone

Based on the cost and air quality considerations, EPA proposes $500/ton as the appropriate cost threshold for the following states which contribute to downwind nonattainment and/or maintenance problems in 2012, but which are not linked to ozone air quality problems in either Houston or Baton Rouge: Connecticut, Delaware, the District of Columbia, Indiana, Iowa, Kansas, Maryland, Massachusetts, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Virginia, and West Virginia.

For states linked to ozone air quality problems in Houston or Baton Rouge, EPA has not yet identified a cost threshold for eliminating significant contribution. EPA does, however, propose to find that those states must make at least all of the reductions that can be achieved for $500/ton in 2012. These states are: Alabama, Arkansas, Florida, Georgia, Illinois, Kentucky, Louisiana, Mississippi, Tennessee, and Texas. For these states, the $500/ton threshold represents emissions reductions that EPA believes are an essential part of the ultimate emissions reductions amount that will be required to eliminate the significant contribution and interference with maintenance. This level does not represent a complete significant contribution determination for these states because neither the analysis of costs up to $500/ton, nor the analysis of air quality impacts of the corresponding emissions reductions, suggest that those reductions necessarily represent all reasonable upwind state reductions. For the reasons stated previously in subsection 2.b, EPA believes it is appropriate and consistent with the statutory mandate to consider whether section 110(a)(2)(D)(i)(I) requires further reductions from these states after 2012 for purposes of the 1997 ozone standard.

To determine whether further reductions are warranted, EPA is expeditiously conducting further analysis. EPA is continuing to develop and evaluate NO_X control costs, emissions reductions, and air quality impact information for NO_X controls greater than $500/ton, and to examine facts involving Houston and Baton Rouge, to support a complete determination of significant contribution and interference with maintenance for states that contribute to one or both of those areas. Based on the analysis done for today's proposal, EPA believes that any additional NO_X reduction requirements would involve reductions from sources beyond EGUs. If this is the case, EPA believes it is likely that we could provide the greatest assistance to states in addressing transport by promulgating a separate rule to achieve those NO_X reductions. EPA believes that developing supplemental information to address these sources beyond EGUs would substantially delay publication of a final rule, beyond the anticipated publication of spring 2011. While EPA intends to move forward aggressively on this issue in gathering the necessary information, EPA does not believe that this effort should delay the reductions and large health benefits associated with this proposed rule. EPA fully intends to proceed with additional rulemaking to fully address the residual significant contribution to nonattainment and interference with maintenance as quickly as possible.

(5) Request for Comment Concerning New York City and Contributing States

As in the case of $PM_{2.5}$, EPA has done additional refined air quality analysis of a 2014 scenario that assumes implementation of the proposed ozone season NO_X emissions reductions, that is, the reductions that would be achieved based on the $500/ton NO_X cost threshold. This air quality analysis, conducted with the CAMx model, can be compared to the results using the air quality assessment tool. The CAMx modeling demonstrated that the

required NO_X reductions would assist many downwind areas with achieving and maintaining the NAAQS. The CAMx air quality modeling for 2014 confirmed the conclusion that Houston and Baton Rouge would continue to have nonattainment/maintenance concerns even with the reduction of NO_X emissions that could be reduced for (at or below) $500/ton. The modeling also showed that the locations within the New York City nonattainment area would continue to have a maintenance problem despite the modeled reductions (including those in New York State). That is, the New York City area is possibly at risk of being in nonattainment in light of historical year-to-year variability in ozone levels in the New York City area. For that reason, EPA is taking comment on whether it should consider and analyze the NO_X reductions that can be achieved for greater than $500/ton in states that are linked to the New York area sites. These states include: Connecticut, Delaware, Indiana, Kentucky, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia. If EPA were to conclude that additional analysis is necessary, it would present the results of this in a future notice that would also consider whether and to what extent states linked to New York City, Houston, and Baton Rouge should be required to make additional NO_X reductions in order to eliminate all significant contribution with respect to the 1997 ozone NAAQS.

3. Discussion of Control Costs for Sources Other Than EGUs

Previously in this section (see discussion in IV.D.2 previously) EPA discusses its proposed cost criteria for identifying SO_2 and NO_X emissions reductions necessary to eliminate at least part of each state's significant contribution and to eliminate at least part of each upwind state's interference with maintenance of the $PM_{2.5}$ NAAQS. In addition, EPA discusses interim cost criteria for ozone. Consistent with these criteria, EPA does not believe that other source categories have emissions that are currently significantly contributing to nonattainment or interfering with maintenance of the 1997 and 2006 $PM_{2.5}$ NAAQS. Thus, with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS, we are not proposing to include in the FIPs emissions reductions requirements for other source categories.

(a) SO_2 Sources and Costs

As described previously, EPA is proposing to define significant contribution on the basis of cost informed by air quality impacts, and to conclude $2,000/ton represents the highest cost value necessary for SO_2 to eliminate significant contribution and interference with maintenance. For SO_2, as described previously, EPA is proposing to conclude that significant contribution and interference with maintenance would be eliminated at costs of no more than $2,000/ton, and in some states, at lower costs. The EPA has not identified SO_2 reductions for sources other than EGUs at $2,000/ton or less (in year 2006 $).

For the CAIR, EPA included a technical support document[64] which noted that for SO_2, EGUs were the dominant contributor to transported emissions, but that there were a few additional categories for which regional emissions exceeded 1 percent of the overall inventory in the eastern half of the U.S. EPA has updated this analysis with a review of the year 2012 inventory, with similar conclusions. *See* TSD—"Non-EGU Emissions Reductions Cost and Potential." The highest-emitting categories of non-EGU SO_2 emissions are: (1) Industrial, commercial, and institutional (ICI) boilers, (2) Portland cement manufacturing, (3) petroleum refining, and (4) sulfuric acid manufacturing.

For ICI boilers, most of the SO_2 emissions are from coal-fired boilers, and to a lesser degree from residual or distillate oil-fired boilers. Possible ways to reduce SO_2 emissions from ICI boilers include fuel switching, flue gas desulfurization, and dry sorbent duct injection. Because of variability in operations, it is difficult to identify precise cost per ton estimates for fuel switching and sorbent injection. For industrial boilers, the capacity factor (that is, the fraction of boiler capacity that is used in a year) can have a significant impact on the cost per ton estimate. Regarding flue gas desulfurization, a recent report prepared by NESCAUM[65] suggests scrubber costs are typically well above $2,000/ton for ICI boilers.

For Portland cement manufacturing, information from a 2006 report prepared by the Lake Michigan Air Directors Consortium (LADCO) estimated costs for SO_2 scrubbing to be between $2,211–6,917 per ton (in year 2003 $). The LADCO "white papers" discussion is available from the following Web site: *http://www.ladco.org/reports/control/final_reports/identification_and_evaluation_of_candidate_control_measures_ii_june_2006.pdf*.

For petroleum refining, the largest sources of SO_2 emissions are from catalytic cracking, sulfur recovery units, and process heaters. For each of the sources in the petroleum refining sector, EPA believes that SO_2 controls at or below $2,000/ton will generally not be available at refineries covered by the recent settlement agreements EPA has entered into with numerous petroleum refineries. Moreover, such agreements cover 88 percent of U.S refining capacity, and will lead to up to 250,000 tons of SO_2 emissions reductions annually. Compliance with these agreements has already taken place at most affected refineries, and these reductions are generally reflected in our 2012 base case emissions inventory.[66]

For sulfuric acid manufacturing, the SO_2 emissions are related to the percent recovery of sulfuric acid product. Because the percent recovery is plant-specific, the available emissions reductions and the cost per ton of controls are highly variable. At the time of the CAIR, EPA made rough calculations that the then-existing 126,000 tons of SO_2 would be reduced by about one-half if all of the sulfuric acid manufacturing in the eastern U.S. was controlled to meet the NSPS level of 4 pounds of SO_2 per ton of product. EPA did not develop cost estimates for these approximate reductions and such cost estimates are still not available. EPA notes, however, that it has entered into a number of settlement agreements with sources in the sulfuric acid production industry, and a significant amount of the estimated available reductions has already been realized. Over 36,000 tons of SO_2 reductions have taken place at 22 plants in the U.S. by 2012 as a result of 6 settlement agreements.[67] More than half of these plants are in states affected by this proposal.

This information shows that few if any SO_2 reductions are available from other source categories and thus, along with other information available to EPA, supports EPA's proposal not to include non-EGU SO_2 reduction requirements for addressing $PM_{2.5}$ transport for the proposed rule. EPA seeks comment on whether non-EGU emissions reductions should be required and on the specific

[64] Identification and Discussion of Sources of Regional Point Source NO_X and SO_2 emissions other than EGUs. EPA/OAQPS and CAMD. January 2004.

[65] Reference: NESCAUM Applicability and Feasibility of NO_X, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers. NESCAUM, November 2008. pp. xvii, 3–12–13.

[66] U.S. EPA. Petroleum Refinery National Priority Case Results. Available at *http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html.*

[67] U.S. EPA. Acid Plant NSR Enforcement Priority. Available at *http://www.epa.gov/compliance/civil/caa/acidplant-nsr/index.html.*

control measures that would serve as the basis for those reductions.

Because sulfur content of both gasoline and diesel fuel are now subject to very stringent sulfur requirements, EPA believes there are no available on-road and nonroad engine measures to reduce mobile source SO_2 at or below $2,000/ton.

b. NO_X From Non-EGU Sources

For NO_X, the methodology described previously in section IV.D.2 requires all states linked to $PM_{2.5}$ nonattainment and maintenance areas to ensure that emissions do not increase above 2009 levels. This translates into a cost cutoff of $500/ton. In addition, for ozone, EPA determined that a number of states can eliminate their significant contribution and interference with maintenance by installing controls at this same $500/ton cost threshold.

For the CAIR, the technical support document [68] evaluating non-EGU controls contained a discussion of non-EGU category contributions to the overall NO_X emissions inventory and a discussion of available controls. This analysis identified source categories for which regional emissions exceeded 1 percent of the overall inventory in the eastern half of the U.S. EPA has updated this analysis of non-EGU NO_X controls done for the CAIR with a review of the year 2012 inventory. *See* TSD—"Non-EGU Emissions Reductions Cost and Potential." The highest-emitting stationary source categories of non-EGU NO_X emissions are: (1) Stationary reciprocating internal combustion engines (RICE), (2) industrial, commercial, and institutional (ICI) boilers, (3) Portland cement manufacturing, (4) petroleum refining, (5) glass manufacturing, (6) pulp and paper production, and (7) iron and steel production.

EPA has not identified additional non-EGU controls that can be achieved at $500/ton or less. For example, available information [69] suggests that costs of various types of NO_X controls are greater than this level for non-EGU sources such as ICI boilers, iron and steel mills, petroleum refineries, [70] glass manufacturing plants, and asphalt manufacturing plants. For industrial boilers, a recent report prepared by NESCAUM [71] suggests NO_X control costs are typically well above $500/ton for ICI boilers. In addition, a recent report prepared by LADCO [72] indicated NO_X control costs are also well above $500/ton for glass manufacturing plants and asphalt manufacturing plants.

For the NO_X SIP Call, EPA identified a number of categories where costs were less than $2,000/ton (1990 dollars), including large ICI boilers with capacities greater than 250 million BTU/hour, cement kilns, and large RICE emitting more than 1 ton NO_X per day. For each of these categories regulated under the NO_X SIP Call, EPA believes there are no available control measures (especially that could be implemented by 2012) at or below $500/ton.

EPA has not identified further controls for stationary nonpoint sources or mobile source NO_X measures that have costs at or below $500 per ton.

E. State Emissions Budgets

As described later, EPA used the cost thresholds identified for each covered state in the previous section and applied them to state-specific data to develop individual state emissions budgets. These budgets facilitate implementation of the requirement that significant contribution and interference with maintenance be eliminated. A state's emissions budget is the quantity of emissions that would remain in that state from covered sources after elimination of that portion of each state's significant contribution and interference with maintenance that EPA has identified in today's proposal, before accounting for the inherent variability in power system operations (*see* discussion of variability in section IV.F, later). The state emissions budget is a mechanism for converting the quantity of emissions that a state must reduce (*i.e.*, the state's significant contribution and interference with maintenance) into enforceable control requirements. In other words, it provides a quantity of emissions to use in developing a remedy (*e.g.*, the remedy should be designed to achieve the budget in an average year).

Because the budget represents emissions that would remain without accounting for variability, it also represents the amount of emissions that would remain after significant contribution and interference with maintenance have been addressed, in an average year. In a year when base case emissions would have been higher than average (*e.g.*, because a large nuclear unit was out of service and more fossil-fuel-fired generation was needed), the emissions that would remain after significant contribution and interference with maintenance had been addressed also would be higher. The variability limits discussed in section IV.F address this issue. Application of variability limits in the remedies is described in section V.D.

1. Defining SO_2 and Annual NO_X State Emissions Budgets for EGUs

For group 1 states required to make deeper emissions reductions in 2014, EPA based each state's 2014 budgets on the same projections from IPM that were used as inputs into the cost curves explained in section IV.D.2.a previously. For SO_2, the values were taken from an IPM run requiring all SO_2 reductions available at $2,000/ton. For group 2 states (and for the first phase 2012 budgets for sources required to make greater reductions in 2014), EPA took a different approach. These states are only required to make SO_2 reductions that could be made through (1) the operation of existing scrubbers, (2) scrubbers that are expected to be built by 2012 and (3) the use of low sulfur coal. Because those strategies were already being applied in most states covered by this rule in 2009,[73] EPA believes that the actual performance units achieved in 2009 is more representative of expected emissions than what EPA modeled using IPM. This is because real data takes into account actual unit by unit information that is represented at a more aggregate level in IPM. The only exception to this rule is if a source was modeled to install a scrubber by 2012 (because of rules requiring that installation and/or because of information that the company had already contracted to install a scrubber). In this case, EPA adjusted emissions from the unit to account for the new scrubber.

For 2012 NO_X budgets, EPA used the same general methodology for all states that was used for the group 2 states for SO_2. The $500/ton cost threshold, that EPA has determined can be used to calculate the minimum significant contribution from upwind states linked to downwind nonattainment and maintenance areas, almost exclusively

[68] Identification and Discussion of Sources of Regional Point Source NO_X and SO_2 emissions other than EGUs. EPA/OAQPS and CAMD. January 2004.

[69] Reference: Identification and Evaluation of Candidate Control Measures. Phase II Final Report. LADCO, June. 2006. Appendix B.

[70] Reference: Assessment of Control Technology Options For Petroleum Refineries in the Mid-Atlantic Region. Final Report. MARAMA, January 2007. p. 2–24.

[71] Reference: NESCAUM Applicability and Feasibility of NO_X, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers. NESCAUM, November 2008. pp. xvii, 3–12–13.

[72] Reference: Identification and Evaluation of Candidate Control Measures. Phase II Final Report. LADCO, June 2006. Appendix B.

[73] Even though allowance prices dropped significantly in 2008 after the Court decision, most sources appear to have continued with the same reduction strategies.

represents reductions from turning on SCR units. EPA believes that instead of defining the budgets based on IPM projections of what will happen when SCR units are turned on, it is better to use real data, therefore EPA has developed budgets based on a combination of historical heat input, historical emissions rates, and, where new SCR units are expected between now and 2012, projected emissions rates for those new SCR units. The emissions budgets developed using the previous methodology are as follows in Table IV.E–1:

TABLE IV.E–1—SO_2 AND ANNUAL NO_X STATE EMISSIONS BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY [74]

[Tons]

State	SO_2, 2012 and 2013	SO_2, 2014 and later	NO_X annual, all years
Alabama	161,871	161,871	69,169
Connecticut	3,059	3,059	2,775
Delaware	7,784	7,784	6,206
District of Columbia	337	337	170
Florida	161,739	161,739	120,001
Georgia	233,260	85,717	73,801
Illinois	208,957	151,530	56,040
Indiana	400,378	201,412	115,687
Iowa	94,052	86,088	46,068
Kansas	57,275	57,275	51,321
Kentucky	219,549	113,844	74,117
Louisiana	90,477	90,477	43,946
Maryland	39,665	39,665	17,044
Massachusetts	7,902	7,902	5,960
Michigan	251,337	155,675	64,932
Minnesota	47,101	47,101	41,322
Missouri	203,689	158,764	57,681
Nebraska	71,598	71,598	43,228
New Jersey	11,291	11,291	11,826
New York	66,542	42,041	23,341
North Carolina	111,485	81,859	51,800
Ohio	464,964	178,307	97,313
Pennsylvania	388,612	141,693	113,903
South Carolina	116,483	116,483	33,882
Tennessee	100,007	100,007	28,362
Virginia	72,595	40,785	29,581
West Virginia	205,422	119,016	51,990
Wisconsin	96,439	66,683	44,846
Total	3,893,870	2,500,003	1,376,312

For more detail on how the budgets were developed, *see* the TSD: "State Budgets, Unit Allocations, and Unit Emissions Rates".

2. Defining Ozone Season NO_X State Emissions Budgets for EGUs

Ozone season NO_X budgets were developed the same way as the annual NO_X budgets were developed (explained in IV.E.1, previously).

TABLE IV.E–2—OZONE-SEASON NO_X STATE EMISSIONS BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY

[Tons]

State	NO_X ozone season, all years
Alabama	29,738
Arkansas	16,660
Connecticut	1,315
Delaware	2,450
District of Columbia	105
Florida	56,939
Georgia	32,144
Illinois	23,570
Indiana	49,987
Kansas	21,433
Kentucky	30,908
Louisiana	21,220
Maryland	7,232
Michigan	28,253
Mississippi	16,530
New Jersey	5,269
New York	11,090
North Carolina	23,539
Ohio	40,661
Oklahoma	37,087
Pennsylvania	48,271
South Carolina	15,222
Tennessee	11,575
Texas	75,574
Virginia	12,608
West Virginia	22,234
Total	641,614

These budgets are based on a 5 month ozone season (May 1 through September 30). Consistent with the approach taken by the OTAG, the NO_X SIP Call, and the CAIR, we propose to define the ozone season, for purposes of emissions

[74] The impact of variability on the budgets is discussed in section IV.F, later.

reductions requirements in this rule, as May through September. We recognize that this ozone season for regulatory requirements will have differences from the official state-specific ozone monitoring season. EPA requests comment on whether the budgets for the final rule should be based on a longer ozone season, such as March through October.

F. Emission Reduction Requirements Including Variability

In this section, EPA discusses the inherent variability in electric power system operation and presents proposed variability limits for each state. As explained below, EPA proposes to calculate variability limits for each state and to use those variability limits in conjunction with the budgets (which are based on expected average conditions) to provide limited flexibility (within the limits allowed by the variability provisions) to address years in which more fossil generation occurs than projected in the average base case year. This section also presents projected emission reduction results.

1. Variability

a. Introduction to Power Sector Variability

Historically, power sector emissions have varied over time. Factors, such as fuel switching and installing new emissions controls, which can lead to significant decreases in emissions, primarily affect emissions rates rather than generation and change largely as a result of pollution regulation.

Even when emissions rates do not change from year to year, overall emissions can change because of factors including power demand, timing of maintenance activities, and unexpected shutdowns of units. Extreme weather conditions, sudden economic shocks, and other unpredictable events can also significantly impact power generation from fossil units. These factors relate directly to heat input, generation, and the routine operation of power plants to supply our electricity, and thus affect total emissions.

As discussed previously, EPA has identified a specific amount of emissions that must be prohibited by each state to satisfy the requirements of CAA section 110(a)(2)(D)(i)(I). EPA has also developed state budgets based on its projections of state emissions in an average year after the elimination of such emissions. However, because of the unavoidable variability in baseline emissions—resulting from the inherent variability in power plant operations—state-level emissions may vary somewhat after all significant contribution and interference with maintenance that EPA has identified in this proposal are eliminated. This occurs even when the emissions rates of the units within the state do not change. For this reason, EPA has determined that it is appropriate to develop variability limits for each state budget. These limits are used to identify the range of emissions that EPA believes may occur in each state following the elimination of all significant contribution and interference with maintenance.

For the proposed rule, EPA proposes to factor this variability explicitly in its consideration of how to control emissions. The Agency believes that because baseline emissions are variable, emissions after the elimination of all significant contribution are also variable and thus it is appropriate to take this variability into account.

As discussed in detail in section V, EPA proposes and considers specific regulatory remedies that are designed to meet the emissions budget in an average year. Because base case emissions may vary from projections, EPA believes these same remedies may incorporate provisions that account for variability. This variability, however, must be limited to provide downwind states with assurance that necessary reductions will be made in upwind states. This section describes how EPA calculated variability limits for each state to achieve this goal.

Remedies (*i.e.*, regulatory approaches for achieving emissions reductions) can range from emissions rate-based "direct control" options to options which allow for interstate trading. EPA believes that inherent variability in power system operations affects each state's baseline emissions and thus also affects a state's emissions after elimination of all significant contribution and interference with maintenance. Thus, emissions may vary somewhat after implementation of the remedies under consideration. Under an emissions rate-based approach, emissions rate limits could be developed that would meet the budget assuming a given pattern of operation for the affected units. If some of the units with higher emissions rates actually operated more than projected, the state's actual emissions would be higher. In an interstate trading program, budgets could be developed that each state would be projected to meet in an average year. In some years, however, generation from units in one state may increase (with a corresponding increase in emissions), but because variability in a larger region is less significant than within a single state, the increase in one state would be expected to be offset by decreases in other states. Finally, even in an intrastate-only trading program, the ability to bank allowances could mean that in one year, emissions would be below the budget, while in another year they would be above.

In all these cases, variability limits can be used to retain the flexibilities that the various remedies provide to deal with real-world variability in the operating system, while still providing downwind states reasonable certainty about the level of upwind emissions.

EPA also notes that explicit consideration of variability in the emissions resulting from a remedy is consistent with removing a state's "significant contribution." As noted previously, even if the emissions result is variable from year to year, there is still a similar increment of emissions reductions. For example, because increased emissions in the control case would also correspond to increased emissions in the base case, the increment of emissions representing significant contribution and interference with maintenance would still be removed. Finally, as is explained more below in IV.F.b, the variability limits (as applied, for instance, in the State Budgets/Limited Trading remedy in section V.D.4) are relatively low and thus the total amount of variability allowed is very small compared to total EGU emissions and even smaller when considering all of the emissions within a state. It is also worth noting that in the proposed State Budgets/Limited Trading remedy, variability is taken into account in such a way that does not allow an overall increase in emissions. Under this remedy, an individual state could emit up to its budget plus variability limit. However, the requirement that all sources hold allowances to cover emissions, and the fact that those allowances are allocated based on state-specific budgets absent variability, would ensure that total emissions do not increase. This remedy, therefore, ensures not only that total emissions do not increase above state budgets, but also that reductions occur in each and every state.

b. How EPA Accounted for Inherent Power Sector Variability

EPA determined 1-year variability limits and 3-year rolling average variability limits for each state. First, EPA determined 1-year variability limits based on historical variability in heat input. Second, EPA determined 3-year rolling average variability limits using statistical methods to convert the 1-year variability into 3-year variability. The approaches EPA used to determine the

1-year and 3-year limits are summarized later and described in more detail in the Power Sector Variability TSD.

Expected variability over a single year. EPA performed analyses using historical data to demonstrate that there is year-to-year variability in baseline emissions (even when emissions rates for all units are held constant) and to quantify the magnitude of this variability. This year-to-year variability in emissions is reflected, in combination with other factors, in year-to-year variability in air quality.

The focus of the analysis is on quantifying the magnitude of the inherent variability in the baseline emissions (on both a 1-year and a 3-year basis). The goals of this analysis, therefore, are to determine the typical variability in emissions that is due to changes in generation, and not due to changes in emission limits, and to set emissions criteria limits that can be used as part of a remedy to ensure that states are eliminating their significant contribution and interference with maintenance to protect air quality.

EPA used statewide average emissions rates projected using IPM to convert historical heat input variability into corresponding emissions variability limits. The approach assessed the variability in state-level heat input over a 7-year time period (2002 through 2008) using the standard deviation and then determined the difference in emissions from the 95th percent two-tailed confidence level and the mean.[75] The approach resulted in a maximum allowable variability, in tons, for each state. These values were then divided by the mean emissions values over the 7-year time period to yield a percentage variability value for each state. *See* the Power Sector Variability TSD for details.

From the state-by-state tonnage and percentage emission variability values, EPA identified a single set of variability levels (that is, a tonnage and a percentage) based on the historic variability. EPA made the decision to adopt a single, uniform tonnage and percentage level pairing to apply to all states in order to make the application of the variability limits straightforward rather than developing state-by-state percentage variability values. The effect of the pairing is to ensure that each state is allowed adequate variability while minimizing the total amount of emissions allowed. Using, for all states, only a constant percentage (reflecting emissions variability in smaller states with a greater range of emissions in percentage terms) would result in large states being allowed greater variability than needed. Conversely, using only a constant tonnage (reflecting emissions variability in larger states with a greater range of emissions in tonnage terms) would result in small states being allowed greater variability than needed. To ensure adequate variability limits—even in states with small numbers of units where expected variability would be more pronounced in percentage terms, and in large states where expected variability would be more pronounced in absolute tonnage terms—EPA derived variability limits both as a percentage and in terms of absolute emissions (tons) that serve to minimize the total amount of emissions allowed under this combination variability limit approach.

For the tonnage and percentage limit criteria, EPA looked at a wide range of percentage and tonnage combinations, and chose for further investigation combinations that provided states sufficient variability limits (based on historic variability) and fit the requirement of minimizing the allowed emissions. Power plants in states that were close to the variability limits were evaluated more closely to ensure the modeling reflected all controls known to operate. EPA believes that the chosen limits would not be tighter than these states could be expected to meet.

This approach (identifying both a tonnage and a percentage) addresses the difficulty that smaller states with fewer units could face if only percentages were used to set the limits. For instance, in a small state with a budget of 5,000 tons of SO_2, an infrequently used unit that on average emitted 500 tons when it operated 10 percent of the time could increase its emissions to 1,500 tons by operating 30 percent of the time in a year when there is unusually high demand for that unit. That would result in a 20 percent increase in statewide emissions. In a much larger state, with a budget of 50,000 tons, such a change in operation would only lead to a 1 percent change in statewide emissions.

For both annual NO_X and SO_2, the percentage variability limits are 10 percent of a state's budget and the corresponding tonnage variability limits are 5,000 and 1,700 tons for NO_X and SO_2, respectively. These are the values that result from the approach described previously, *i.e.*, these variability levels allow the necessary variability for every state based on its historic variability, while minimizing the amount of emissions allowed.

EPA assigned each state one of these values—either the tonnage limit or the percent limit, whichever was greater for that state. For instance, 10 percent of Connecticut's SO_2 budget is less than 1,700 tons, so Connecticut received a 1-year 1,700 ton variability limit for its EGU SO_2 emissions. EGU sources in Connecticut could emit up to the state's SO_2 budget plus the variability limit of an additional 1,700 tons of SO_2 in a year, and still eliminate the state's significant contribution and interference with maintenance. Proposed 1-year variability limits for each covered state are shown in the tables in section IV.F.2, later. See the Power Sector Variability TSD for more details on EPA's variability approach.

Expected variability over a 3-year time period. Because air quality is assessed under the Act annually on a rolling 3-year time period, EPA believes that it is appropriate to also evaluate the inherent variability in emissions over similar time periods, and to establish state budgets with variability limits that ensure that the significant contribution and interference with maintenance that EPA has identified in this notice be eliminated.

While the year-to-year variability in emissions could lead to variability in 3-year rolling averages, inherent variability is lower over a 3-year time period than over a 1-year period and thus a state's 3-year variability limit will be lower than the state's 1-year variability limit. Establishing such 3-year limits thus provides an opportunity to ensure that the variability limits do not allow greater fluctuation in emissions than justified based on historic variability. EPA estimated the variability in a state's emissions over a 3-year time period based on the expected variability in emissions for a single year.

As summarized later and described in the Power Sector Variability TSD, the Agency used statistical methods to estimate the 3-year variability based on 1-year variability. The average variability of a multi-year sample is the average variability of a single year divided by the square root of the number of years in the multi-year sample.[76] Thus, the variability of a 3-year average is equal to the annual variability divided by the square root of three. EPA used this approach to determine 3-year variability limits based on the 1-year limits. For example, the Agency calculated the 3-year variability that corresponds to a 1-year variability of 5,000 tons as 5,000 divided by the

[75] The two-tailed 95th percent confidence level is the equivalent of the 97.5th upper (single-tailed) confidence level.

[76] Moore, David S. and George P. McCabe. *Introduction to the Practice of Statistics.* 2nd ed. New York: W.H. Freeman and Company, 1993. p. 395.

square root of three, or 2,887 tons. Similarly, EPA calculated the 3-year variability that corresponds to a 1-year variability of 1,700 tons as 1,700 divided by the square root of three, or 981 tons. EPA decided to use three years instead of some other interval in order to be consistent with 3-year averaging used to assess attainment with the NAAQS, as explained earlier in this section.

Proposed 3-year variability limits for each covered state are shown in the tables in section IV.F.2, later. *See* the Power Sector Variability TSD for more details on EPA's variability approach.

2. State Budgets With Variability Limits

As explained previously, EPA determined variability limits for each state. EPA then applied these variability limits on a state-by-state basis to calculate state-specific emissions budgets with variability limits. EPA calculated state budgets with both 1-year and 3-year variability limits.

Table IV.F–1 shows proposed variability limits by state on SO_2 emissions for 2014 and later. Table IV.F–2 shows proposed variability limits by state on NO_X annual emissions for 2014 and later. EPA requests comment on the proposed variability limits.

EPA also requests comment on an alternative calculation method for variability. The alternative method would use the results of the proposed method but add a ceiling based on the maximum percentage of variability among covered states as observed in the historic heat input data described previously. For both NO_X annual and SO_2, the percentage limits calculated using this alternative methodology are 21 and 28 percent of a state's budget, respectively. Under this alternative calculation method, a state's variability limit would be no lower than 10 percent of its budget and no higher than 21 or 28 percent, for NO_X and SO_2, respectively. Because no state varied more than these percentages, EPA believes they could serve as reasonable caps on variability limits. These limits would address the issue of small states receiving very large variability limits as a fraction of their budgets.

For instance, although Connecticut's proposed 1-year variability limit of 1,700 tons is greater than 10 percent of its SO_2 budget of 3,059 tons (306 tons), it is also greater than 28 percent of the budget (857 tons). Therefore, under this alternative calculation method, Connecticut's 1-year SO_2 variability limit would be 857 tons (28 percent of the state's SO_2 budget). Similarly, for annual NO_X, while Connecticut's proposed 1-year variability limit of 5,000 tons is greater than 10 percent of its NO_X annual budget of 2,775 (278 tons), it is greater than 21 percent of the budget (583 tons). Therefore, under this alternative approach, Connecticut's 1-year annual NO_X variability limit would be 583 tons. Tables IV.F–1 through IV.F–3 show the variability limits under the proposed and alternative calculation methods. *See* the Power Sector Variability TSD in the docket for this rule for more details.

TABLE IV.F–1—VARIABILITY LIMITS ON SO_2 ANNUAL EMISSIONS FOR 2014 AND LATER FOR ELECTRIC GENERATING UNITS

[Tons]

State	SO_2 annual emissions budget	Proposed		Alternative	
		1-year limit	3-year average limit	1-year limit	3-year average limit
Alabama	161,871	16,187	9,346	16,187	9,346
Connecticut	3,059	1,700	981	857	495
Delaware	7,784	1,700	981	1,700	981
District of Columbia	337	1,700	981	94	54
Florida	161,739	16,174	9,338	16,174	9,338
Georgia	85,717	8,572	4,949	8,572	4,949
Illinois	151,530	15,153	8,749	15,153	8,749
Indiana	201,412	20,141	11,629	20,141	11,629
Iowa	86,088	8,609	4,970	8,609	4,970
Kansas	57,275	5,728	3,307	5,728	3,307
Kentucky	113,844	11,384	6,573	11,384	6,573
Louisiana	90,477	9,048	5,224	9,048	5,224
Maryland	39,665	3,967	2,290	3,967	2,290
Massachusetts	7,902	1,700	981	1,700	981
Michigan	155,675	15,568	8,988	15,568	8,988
Minnesota	47,101	4,710	2,719	4,710	2,719
Missouri	158,764	15,876	9,166	15,876	9,166
Nebraska	71,598	7,160	4,134	7,160	4,134
New Jersey	11,291	1,700	981	1,700	981
New York	42,041	4,204	2,427	4,204	2,427
North Carolina	81,859	8,186	4,726	8,186	4,726
Ohio	178,307	17,831	10,295	17,831	10,295
Pennsylvania	141,693	14,169	8,181	14,169	8,181
South Carolina	116,483	11,648	6,725	11,648	6,725
Tennessee	100,007	10,001	5,774	10,001	5,774
Virginia	40,785	4,079	2,355	4,079	2,355
West Virginia	119,016	11,902	6,871	11,902	6,871
Wisconsin	66,683	6,668	3,850	6,668	3,850
Total	2,500,003				

Proposed 1-year variability limits are the larger of (1) 1,700 tons or (2) 10 percent of the state's budget. 3-year limits are the 1-year limits divided by the square root of three.

The alternative 1-year variability limit is 1,700 tons as long as that amount is between 10 and 28 percent of the state's budget. If 1,700 tons is greater than 28 percent of the state's budget, the state's limit is set at 28 percent of its budget. If 1,700 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget.

TABLE IV.F–2—VARIABILITY LIMITS ON NO_X ANNUAL EMISSIONS FOR 2014 AND LATER FOR ELECTRIC GENERATING UNITS

[Tons]

State	NO_X annual	Proposed		Alternative	
		1-year limit	3-year average limit	1-year limit	3-year average limit
Alabama	69,169	6,917	3,993	6,917	3,993
Connecticut	2,775	5,000	2,887	583	336
Delaware	6,206	5,000	2,887	1,303	752
District of Columbia	170	5,000	2,887	36	21
Florida	120,001	12,000	6,928	12,000	6,928
Georgia	73,801	7,380	4,261	7,380	4,261
Illinois	56,040	5,604	3,235	5,604	3,235
Indiana	115,687	11,569	6,679	11,569	6,679
Iowa	46,068	5,000	2,887	5,000	2,887
Kansas	51,321	5,132	2,963	5,132	2,963
Kentucky	74,117	7,412	4,279	7,412	4,279
Louisiana	43,946	5,000	2,887	5,000	2,887
Maryland	17,044	5,000	2,887	3,579	2,066
Massachusetts	5,960	5,000	2,887	1,252	723
Michigan	64,932	6,493	3,749	6,493	3,749
Minnesota	41,322	5,000	2,887	5,000	2,887
Missouri	57,681	5,768	3,330	5,768	3,330
Nebraska	43,228	5,000	2,887	5,000	2,887
New Jersey	11,826	5,000	2,887	2,483	1,434
New York	23,341	5,000	2,887	4,902	2,830
North Carolina	51,800	5,180	2,991	5,180	2,991
Ohio	97,313	9,731	5,618	9,731	5,618
Pennsylvania	113,903	11,390	6,576	11,390	6,576
South Carolina	33,882	5,000	2,887	5,000	2,887
Tennessee	28,362	5,000	2,887	5,000	2,887
Virginia	29,581	5,000	2,887	5,000	2,887
West Virginia	51,990	5,199	3,002	5,199	3,002
Wisconsin	44,846	5,000	2,887	5,000	2,887
Total	1,376,312				

Proposed 1-year variability limits are the larger of (1) 5,000 tons or (2) 10 percent of the state's budget. 3-year limits are the 1-year limits divided by the square root of three.

The alternative 1-year variability limit is 5,000 tons as long as that amount is between 10 and 21 percent of the state's budget. If 5,000 tons is greater than 21 percent of the state's budget, the state's limit is set at 21 percent of its budget. If 5,000 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget.

The NO_X ozone season variability limits have been calculated based on five months of data corresponding to the May through September ozone season. EPA is proposing to use the same approach to calculate ozone season limits that the Agency used to calculate the proposed SO_2 and NO_X annual variability limits described earlier in this section, but adjusted to reflect the ozone season data.

Using that approach, the resulting ozone season 1-year variability limits are 2,100 tons and 10 percent of a state's budget. EPA assigned each state one of these values–either the tonnage limit or the percentage limit, whichever was greater for that state—using the same approach as for the SO_2 and NO_X annual limits described previously. EPA determined the 3-year variability limits as the 1-year limits divided by the square root of three, the same approach used for the SO_2 and NO_X annual limits. The NO_X ozone season limits resulting from this approach are shown in Table IV.F–3.

EPA did not explicitly model ozone season variability limits because it was assumed that the NO_X annual limits would also serve to limit variability in the ozone season and that additional constraints were unnecessary. However, a comparison of the data revealed that these variability limits would be lower than the ozone season emissions shown in EPA's modeling for this proposed rule in seven states, with the difference ranging from less than 100 tons to about 900 tons. Adding these ozone season variability limits would, presumably, change the NO_X emissions projections in the IPM modeling, but the differences are expected not to make a noticeable impact in the overall air quality results.

As with the SO_2 and NO_X annual variability limits, EPA also calculated NO_X ozone season limits using the alternative calculation method described previously; the alternative method adds a ceiling based on the maximum percentage of variability among covered states as observed in the historic heat input data. For NO_X ozone season, the percentage limit ceiling would be 27 percent of a state's budget. The NO_X ozone season limits resulting from this approach are also shown in Table IV.F–3.

EPA requests comments on the NO_X ozone season limits shown in Table IV.F–3.

TABLE IV.F–3—VARIABILITY LIMITS ON NO_X OZONE EMISSIONS FOR 2014 AND LATER FOR ELECTRIC GENERATING UNITS

[Tons]

State	NO_X ozone season emissions budget	Proposed		Alternative	
		1-year limit	3-year average limit	1-year limit	3-year average limit
Alabama	29,738	2,974	1,717	2,974	1,717
Arkansas	16,660	2,100	1,212	2,100	1,212
Connecticut	1,315	2,100	1,212	355	205
Delaware	2,450	2,100	1,212	662	382
District of Columbia	105	2,100	1,212	28	16
Florida	56,939	5,694	3,287	5,694	3,287
Georgia	32,144	3,214	1,856	3,214	1,856
Illinois	23,570	2,357	1,361	2,357	1,361
Indiana	49,987	4,999	2,886	4,999	2,886
Kansas	21,433	2,143	1,237	2,143	1,237
Kentucky	30,908	3,091	1,784	3,091	1,784
Louisiana	21,220	2,122	1,225	2,122	1,225
Maryland	7,232	2,100	1,212	1,953	1,127
Michigan	28,253	2,825	1,631	2,825	1,631
Mississippi	16,530	2,100	1,212	2,100	1,212
New Jersey	5,269	2,100	1,212	1,423	821
New York	11,090	2,100	1,212	2,100	1,212
North Carolina	23,539	2,354	1,359	2,354	1,359
Ohio	40,661	4,066	2,348	4,066	2,348
Oklahoma	37,087	3,709	2,141	3,709	2,141
Pennsylvania	48,271	4,827	2,787	4,827	2,787
South Carolina	15,222	2,100	1,212	2,100	1,212
Tennessee	11,575	2,100	1,212	2,100	1,212
Texas	75,574	7,557	4,363	7,557	4,363
Virginia	12,608	2,100	1,212	2,100	1,212
West Virginia	22,234	2,223	1,284	2,223	1,284
Total	641,614				

Proposed 1-year variability limits are the larger of (1) 2,100 tons or (2) 10 percent of the state's budget. 3-year limits are the 1-year limits divided by the square root of three.

The alternative 1-year variability limit is 2,100 tons as long as that amount is between 10 and 27 percent of the state's budget. If 2,100 tons is greater than 27 percent of the state's budget, the state's limit is set at 27 percent of its budget. If 2,100 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget.

As discussed in section V.D, the proposed FIPs would apply the 1-year variability limits commencing in 2014 and the 3-year variability limits commencing in 2016, noting that application of the 3-year average limits in 2016 would serve to limit each state's emissions in 2014 and 2015. The Agency also requests comment on whether the remedy in the proposed FIPs should be modified so that the limits would apply starting in 2012 instead of 2014. In addition, the direct control remedy option on which EPA requests comments includes assurance provisions based on these variability limits that would apply starting in 2012. Thus, EPA also explains later what variability limits would apply in 2012 and 2013. The 1-year variability limits for 2012 and 2013 would be the same as the variability limits for 2014 and later in Tables IV.F–1, IV.F–2, and IV.F–3 for all state budgets except for the SO_2 budgets for the 15 states comprising the stringent SO_2 tier ("group 1"), which have different SO_2 budgets in 2012 and 2013 than in 2014 and beyond.

If EPA finalizes a remedy that uses the 2012 and 2013 variability limits, EPA would also start applying the 3-year variability limits in 2014 (for all state budgets except group 1 SO_2 budgets) which would serve to limit each state's emissions in 2012 and 2013, in the same way that starting the 3-year limits in 2016 would serve to limit emissions in 2014 and 2015 under the proposed approach. The 3-year variability limits would be the same as the 3-year limits for 2014 and later in Tables IV.F–1, IV.F–2, and IV.F–3.

In this alternative approach, the 15 SO_2 group 1 states, which have different SO_2 budgets in 2012 and 2013 than in 2014 and beyond, would be subject to different 1-year variability limits in 2012 and 2013 than in later years. All of the group 1 states have sufficiently large SO_2 budgets in 2012 and 2013 that the tonnage limit of 1,700 tons would not apply and the 1-year limits would be 10 percent of the state SO_2 budgets. The 2012 and 2013 1-year limits on SO_2 emissions for these 15 states under this alternative approach are shown later in Table IV.F–4.

Additionally, commencing in 2013, EPA would apply in these 15 states a distinct 2-year average variability limit on SO_2 emissions for the years 2012 and 2013. Analogous to the 3-year average in subsequent years, this 2-year average limit would restrict average variability in 2012 and 2013 more than the 1-year average alone. Table IV.F–4 shows, for this alternative approach, 2-year variability limits on SO_2 emissions for 2012 and 2013 for the 15 group 1 states. For these states, the 3-year variability limits for later years would be as shown in Tables IV.F–1, IV.F–2, and IV.F–3.

For an alternative approach where variability limits start in 2012 instead of 2014, EPA considered—instead of two-year average limits on SO_2 emissions in the 15 group 1 states in 2012 and 2013—applying 3-year average limits in these states starting in 2014. This would be the same method as for all other state budgets under the alternative where variability limits start in 2012. However, because the 15 group 1 states have different SO_2 budgets in 2012 and 2013 than in 2014 and beyond, calculation of the 3-year average limits to apply in

years spanning the two budget levels is less straightforward. EPA analyzed this alternative method for the 15 SO_2 group 1 states and compared results to the results using the 2-year average limits in 2012 and 2013 for these states, and determined that the 2-year average approach is reasonable. *See* the Power Sector Variability TSD for more information.

Table IV.F–4 includes 1-year and 2-year variability limits calculated according to the proposed methodology. The 2-year limits are the 1-year limits divided by the square root of two. The table does not include separate columns with variability limits calculated according to the alternative calculation method (*i.e.*, the method that adds a ceiling based on the maximum percentage of variability in historic data, described previously) because for the SO_2 budgets in Table IV.F–4 the alternative calculation method would yield identical results to the proposed method. The Power Sector Variability TSD contains more details on the variability limits.

TABLE IV.F–4—2012–2013 ONE- AND TWO-YEAR VARIABILITY LIMITS ON SO_2 EMISSIONS FOR GROUP 1 STATES FOR ELECTRIC GENERATING UNITS

[Tons]

State	SO_2 annual emissions budget	1-year limit	Two-year average limit
Georgia	233,260	23,326	16,494
Illinois	208,957	20,896	14,775
Indiana	400,378	40,038	28,311
Iowa	94,052	9,405	6,650
Kentucky	219,549	21,955	15,524
Michigan	251,337	25,134	17,772
Missouri	203,689	20,369	14,403
New York	66,542	6,654	4,705
North Carolina	111,485	11,149	7,883
Ohio	464,964	46,496	32,878
Pennsylvania	388,612	38,861	27,479
Tennessee	100,007	10,001	7,072
Virginia	72,595	7,260	5,133
West Virginia	205,422	20,542	14,526
Wisconsin	96,439	9,644	6,819

1-year variability limits calculated by the proposed method are the larger of (1) 1,700 tons or (2) 10 percent of the state's budget. Two-year limits are the 1-year limits divided by the square root of two.

The alternative 1-year variability limit is 1,700 tons as long as that amount is between 10 and 28 percent of the state's budget. If 1,700 tons is greater than 28 percent of the state's budget, the state's limit is set at 28 percent of its budget. If 1,700 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget. The alternative calculation method would yield identical limits to the limits determined using the proposed method for the budgets in Table IV.F–4, because for each of these budgets, 1,700 tons is less than 10 percent of the budget.

3. Summary of Emissions Reductions Across All Covered States

Table IV.F–5 presents projected power sector emissions in the base case (*i.e.*, without the proposed Transport Rule or CAIR) compared to projected emissions with the proposed Transport Rule in 2012 and 2014 for all covered states. Table IV.F–6 presents 2005 historical power sector emissions compared to projected emissions with the Transport Rule in 2012 and 2014.

TABLE IV.F–5—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO BASE CASE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.4	5.0	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.3	0.7
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

Note: Emissions differ from emissions budgets due to banking.

TABLE IV.F–6—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS

[Million tons]

	2005 actual emissions	2012 transport rule emissions	2012 emissions reductions from 2005	2014 transport rule emissions	2014 emissions reductions from 2005
SO_2	8.9	3.4	5.5	2.6	6.3

TABLE IV.F–6—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS—Continued

[Million tons]

	2005 actual emissions	2012 transport rule emissions	2012 emissions reductions from 2005	2014 transport rule emissions	2014 emissions reductions from 2005
Annual NO_X	2.7	1.3	1.4	1.3	1.4
Ozone Season NO_X	0.9	0.6	0.3	0.6	0.3

Note: Emissions differ from emissions budgets due to banking.

G. How the Proposed Approach Is Consistent With Judicial Opinions Interpreting Section 110(a)(2)(D)(i)(I) of the Clean Air Act

The methodology described previously quantifies states' significant contribution and interference with maintenance in a manner that is consistent with the decisions of the DC Circuit. As discussed in section III previously, the DC Circuit has issued two significant decisions addressing the requirements of 110(a)(2)(D)(i)(I). The first opinion largely upheld the NO_X SIP Call, *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), and the second found significant flaws in the CAIR, *North Carolina* v. *EPA,* 531 F.3d. 896 (DC Cir. 2008). In both cases, the Court considered aspects of the methodology used by EPA to identify emissions that, pursuant to section 110(a)(2)(D)(i)(I), must be eliminated due to their impact on air quality in downwind states. EPA believes that the methodology used in this proposed Transport Rule is consistent with both opinions and rectifies the flaws the *North Carolina* Court identified with the methodology used in CAIR. The methodology used for this proposed rule relies on state-specific data to analyze each individual state's significant contribution, uses air quality considerations in addition to cost considerations to identify each state's significant contribution, and gives independent meaning to the "interference with maintenance" prong. This methodology is then applied in a reasonable manner consistent with the relevant judicial opinions.

In *North Carolina,* the Court held that EPA's approach to evaluating significant contribution was inadequate because, by evaluating only whether emissions reductions were highly cost effective "at the regional level assuming a trading program", it failed to conduct the required state-specific analysis of significant contribution. *See id.* at 907. EPA, the Court concluded, "never measured the 'significant contribution' from sources within an individual state to downwind nonattainment areas." *Id.* The Court did not, however, disturb the air-quality-based methodology used by EPA to identify the states with contributions large enough to warrant further consideration.

For this proposed transport rule, EPA uses a first step similar to that used in the CAIR to identify the states with relatively large contributions. However, in contrast to the CAIR, it then uses a state-specific analysis. Instead of identifying a single emissions level that could be achieved by the application of highly cost effective controls in the region, EPA determines, on a state-by-state basis what reductions could effectively be achieved by sources in that state. EPA's new approach does not, as the CAIR methodology did, establish a regional cap on emissions that is then divided into state budgets that set the emission reduction requirements for each state. Instead, EPA develops, for each covered state, emissions budgets based on the reductions achievable at a particular cost per ton in that particular state, taking into account the need to ensure reliability of the electric generating system. The selected cost/ton levels reflect consideration of both cost factors and air quality factors including the estimated impact of upwind states' emissions on each downwind receptor.

In addition, in developing this approach, EPA was guided by the Court's holdings regarding the use of cost to identify significant contribution. Specifically, the Court held in *Michigan* that EPA could "in selecting the 'significant' level of 'contribution' under section 110(a)(2)(D)(i)(I), choose a level corresponding to a certain reduction in cost." *North Carolina,* 531 F.3d at 917 (citing *Michigan,* 213 F.3d at 676–77). This holding also supported the Court's conclusion in *Michigan* that it was acceptable for EPA to apply a uniform cost-criterion across states. *See Michigan,* 213 F.3d at 679. In the CAIR case, the Court rejected EPA's analysis, not because it relied on cost considerations to identify significant contribution, but because it found that EPA had failed to draw the significant contribution line at all. *See North Carolina,* 531 F.3d at 918 ("* * * here EPA did not draw the [significant contribution] line at all. It simply verified sources could meet the SO_2 caps with controls EPA dubbed 'highly cost-effective.' "). The holdings in *Michigan* regarding the use of cost and a uniform cost-criterion across states were left undisturbed. *See, e.g., North Carolina,* 531 F.3d at 917 (explaining that in Michigan the Court held that "EPA may 'after [a state's] reduction of all [it] could * * * cost-effectively eliminate[ ],' consider 'any remaining contribution insignificant' "). In fact, the Court acknowledged that, based on the Michigan holdings, the measurement of a state's significant contribution need not "directly correlate with each state's individualized air quality impact on downwind nonattainment relative to other upwind states." *North Carolina,* 531 F.3d at 908.

For these reasons, EPA determined that it was appropriate in this rulemaking to consider the cost of controls to determine what portion of a state's contribution is its "significant contribution." However, EPA also heeded the *North Carolina* Court's warning that "EPA can't just pick a cost for a region, and deem 'significant' any emissions that sources can eliminate more cheaply." *North Carolina,* 531 F.3d at 918. Thus, in this rulemaking, EPA departs from the practice used in the NO_X SIP Call and in CAIR of evaluating, based solely on the cost of control required in other regulatory environments, what controls would be considered "highly-cost-effective." Instead, as part of its determination of a reasonable cost per ton for upwind state control, EPA evaluates the air quality impact of reductions at various cost levels and considers the reasonableness of possible cost thresholds as part of a multi-factor analysis.

In addition, the methodology used in this rulemaking gives independent meaning to the interfere with maintenance prong of section 110(a)(2)(D)(i)(I). In *North Carolina,* the Court concluded that CAIR improperly

"gave no independent significance to the 'interfere with maintenance' prong of section 110(a)(2)(D)(i)(I) to separately identify upwind sources interfering with downwind maintenance." *North Carolina,* 531 F.3d at 910. EPA rectified this flaw in this rulemaking by separately identifying downwind "nonattainment sites" and downwind "maintenance sites." EPA decided to consider upwind states' contributions not only to sites that EPA projected would be in nonattainment, but also to sites that, based on the historic variability of their emissions, EPA determined may have difficulty maintaining the relevant standards. The specific mechanism EPA used to implement this approach is described in detail in section IV.C. previously. For annual $PM_{2.5}$, this approach identified 16 maintenance sites in addition to the 32 nonattainment sites identified in the analysis of nonattainment receptors. For 24-hour $PM_{2.5}$ this approach identified 38 maintenance sites in addition to the 92 nonattainment sites identified in the analysis of nonattainment receptors. For ozone it identified 16 maintenance sites in addition to the 11 ozone nonattainment sites identified.

EPA applied this methodology using available information and data to measure the emissions from states in the eastern United States that significantly contribute to nonattainment or interfere with maintenance in downwind areas with regard to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. Although EPA has not completely quantified the total significant contribution of these states with regard to all existing standards, EPA has determined, on a state-specific basis, that the emissions prohibited in the proposed FIPs are either part of or constitute the state's significant contribution and interference with maintenance. Thus, elimination of these emissions will, at a minimum, make measurable progress towards satisfying the 110(a)(2)(D)(i)(I) prohibition on significant contribution and interference with maintenance.

H. Alternative Approaches Evaluated But Not Proposed

EPA evaluated a number of alternative approaches to defining significant contribution and interference with maintenance in addition to the approach proposed in this rule. Stakeholders suggested a variety of ideas. EPA considered all suggested approaches.

EPA evaluated approaches including those based solely on air quality, based solely on cost with a uniform cost in all states, based on cost per air quality impact (*e.g.,* $ per $\mu g/m^3$), and binning of states based on air quality impact. Detailed descriptions of the alternative approaches that EPA evaluated are in a TSD in the docket titled "Alternative Significant Contribution Approaches Evaluated."

EPA is not proposing any of the alternative approaches listed here. However, the proposed approach (described in section IV.D) incorporates some elements from these approaches.

V. Proposed Emissions Control Requirements

This section describes the proposed emissions control requirements in detail. The section starts with V.A which discusses the pollutants included in the proposal, followed by V.B which discusses the source categories covered. Section V.C discusses the timing of the proposed emissions control requirements. Section V.D describes the proposed approach to implement the emission reduction requirements, starting with a description of the NO_X SIP Call and CAIR approaches to implementing reductions and the judicial opinions on those approaches, then describing in detail the proposed "remedy" (State Budgets/Limited Trading) for FIPs that would implement the emissions reductions, and explaining the structure and key elements of the proposed Transport Rule trading program rules for State Budgets/Limited Trading. Section V.D also describes two alternative remedies on which EPA requests comment. Section V.E presents projected costs and emissions for each remedy option. Section V.F discusses the transition from the CAIR cap and trade programs to the proposed Transport Rule programs. Section V.G discusses interactions of the proposed programs with the existing Title IV and NO_X SIP Call programs.

A. Pollutants Included in This Proposal

In this action, EPA is proposing FIPs to directly regulate upwind emissions of SO_2 and NO_X because of their impact on downwind states' ability to attain and maintain the $PM_{2.5}$ NAAQS. EPA is also proposing to regulate upwind emissions of NO_X because of their impact on 8-hour ozone attainment and maintenance in downwind states. Our rationale for regulating these precursor pollutants is discussed in section IV.B. In this section, we also explain the regulatory mechanism we are proposing to use to regulate these pollutants and take comment on two alternative options.

B. Source Categories

EPA is proposing to require emissions reductions from the power sector. This section discusses EPA's rationale for proposing to control power sector emissions, and our rationale for not proposing to control emissions from other source categories at this time.

1. Propose To Control Power Sector Emissions

The proposed Transport Rule FIPs would require EGUs with capacity greater than 25 MWe in the covered states to reduce emissions of SO_2, NO_X, and ozone season NO_X. *See* section V.D.4., later, for a detailed description of the proposed applicability requirements.[77]

Electric generating units are important sources of SO_2 and NO_X emissions. In 2012, considering other controls that will be in place, EPA projects that if a Transport Rule is not implemented, EGUs would emit more than 70 percent of the total man-made SO_2 emissions and about 20 percent of the total man-made NO_X emissions in the group of 32 states that would be affected by this rule (*see* Table III.A–1 in section III for lists of states).[78]

EPA has previously conducted extensive analyses of the cost and emissions impacts of SO_2 and NO_X reduction policies on the power sector using the Integrated Planning Model (IPM). Examples include EPA's IPM analyses of a number of multi-pollutant bills, including the Clean Air Planning Act (S. 843 in 108th Congress), the Clean Power Act (S. 150 in 109th Congress), the Clear Skies Act of 2005 (S. 131 in 109th Congress), the Clear Skies Act of 2003 (S. 485 in 108th Congress), and the Clear Skies Manager's Mark (of S. 131). EPA also analyzed several power sector multi-pollutant scenarios in July 2009 at the request of Senator Tom Carper. These analyses are on EPA's Web site at: (*http://www.epagov/airmarkets/progsregs/cair/multi.html*). EPA's IPM analysis for CAIR is another example: (*http://www.epagov/airmarkets/progsregs/epa-ipm/cair/index.html*).

Based on these analyses, EPA believes that there exist reasonable means for EGUs to make substantial reductions in emissions of SO_2 and NO_X. EPA also believes that, at this time, EGUs can

[77] Certain non-EGUs and smaller EGUs were included in the CAIR NO_X ozone season program in some CAIR states. EPA proposes that such units would not be covered by the Transport Rule requirements; see section V.F in this preamble for further discussion of these units.

[78] Emissions estimates are based on the 2012 baseline projections described in section IV in this preamble.

reduce SO_2 and NO_X emissions more cost-effectively than other source categories (*see* section IV.D for discussion of control costs for non-EGU source categories). For these reasons, EPA has decided to require reductions in SO_2 and NO_X emissions from EGUs in the FIPs in this proposed rule. EPA requests comments on these proposed FIPs and its proposal to require reductions from EGUs.

2. Other Source Categories Are Not Included

In these proposed FIPs, EPA is not proposing to include emission reduction requirements for sources other than EGUs.[79]

a. Why EPA Does Not Require Reductions From Other Source Categories To Address Transport Requirements for $PM_{2.5}$

In the proposed FIPs to address the section 110(a)(2)(D)(i)(I) requirements with respect to the 1997 and 2006 $PM_{2.5}$ standards, EPA proposes to regulate only emissions from EGUs. As discussed previously in section IV.D, EPA's review of the costs of EGU and non-EGU controls resulted in a conclusion that substantial SO_2 and NO_X reductions from EGUs are available at a cost per ton that is lower than the cost per ton of non-EGU controls. Other analyses discussed in section IV.D demonstrated that these EGU reductions are sufficient to eliminate the quantity of emissions identified by EPA as significantly contributing to or interfering with maintenance of the 1997 $PM_{2.5}$ NAAQS in downwind areas. This same section explains that EGU reductions substantially address eliminating the quantity of emissions identified by EPA as significantly contributing to or interfering with maintenance of the 2006 $PM_{2.5}$ NAAQS, and this same section explains the need for EPA to further analyze remaining winter $PM_{2.5}$ exceedances. This conclusion does not, in any way, address whether a FIP promulgated by EPA or SIPs promulgated by the states should include reductions from non-EGU sources in order to eliminate significant contribution and interference with maintenance for any other NAAQS, including the 1997 ozone NAAQS and future NAAQS for $PM_{2.5}$.

b. Why EPA Does Not Propose To Require Reductions From Other Source Categories To Address Transport Requirements for Ozone

In the FIPs for this proposed rule, EPA is only proposing to require reductions from EGUs to address emissions from those source categories that significantly contribute to or interfere with maintenance of the 1997 ozone NAAQS. As discussed previously in section IV.D, EPA's review of the costs of EGU and non-EGU controls resulted in a conclusion that significant NO_X emissions reductions from EGU are available at a cost per ton that is lower than the cost per ton of non-EGU NO_X controls. The same section also explains the need for EPA to further analyze whether fully addressing upwind state responsibilities to reduce NO_X emissions that contribute to downwind nonattainment and maintenance problems requires additional reductions at higher cost per ton, which again would involve analysis of potential EGU and non-EGU reductions and costs. EPA will be moving forward to complete its assessment of pollution transport for the 1997 ozone NAAQS as soon as possible.

For future ozone and $PM_{2.5}$ NAAQS, EPA intends to quantify the emissions reductions needed to satisfy the requirements of 110(a)(2)(D)(i)(I) with respect to those NAAQS. EPA has not made any determinations or assessments regarding whether reductions from source categories other than EGUs will be needed to achieve the necessary reductions in each state.

C. Timing of Proposed Emissions Reduction Requirements

EPA is proposing an initial phase of reductions in 2012 followed by a second phase in 2014. Sources will be required to comply with the annual SO_2 and NO_X requirements by January 1, 2012 and January 1, 2014 for the first and second phases, respectively. Similarly, sources will be required to comply with the ozone season NO_X requirements by May 1, 2012, and by May 1, 2014. EPA chose these dates to coordinate with the NAAQS attainment deadlines and to assure that reductions are made as expeditiously as practicable, as described later in this section. This section also discusses how the compliance deadlines address the Court's concern about timing. Additionally, this section explains that EPA will consider additional reductions to address the NAAQS in the future.

1. Date for Prohibiting Emissions That Significantly Contribute or Interfere With Maintenance of the $PM_{2.5}$ NAAQS

For all areas designated as nonattainment with respect to the 1997 $PM_{2.5}$ NAAQS, the SIP deadline for attaining that standard must be as expeditious as practicable but no later than April 2010, with a possible extension to no later than April 2015. Many areas have already come into attainment by the April 2010 deadline due in part to reductions achieved under CAIR. Because the 2010 deadline will have passed before the Transport Rule is finalized, we decided to coordinate the deadline for eliminating significant contribution under this rule with respect to the 1997 $PM_{2.5}$ NAAQS with the April 2015 deadline that applies to areas that will need an extension of the April 2010 deadline. For all areas designated as nonattainment with respect to the 2006 24-hour $PM_{2.5}$ NAAQS, the attainment deadline must be as expeditious as practicable but no later than December 2014 with a possible extension to as late as December 2019.[80]

Upwind emissions reductions achieved by the 2014 emissions year will help areas that failed to meet the April 2010 deadline, to meet the April 2015 deadline for the 1997 $PM_{2.5}$ NAAQS. These reductions will also help areas meet the December 2014 attainment deadline with respect to the 2006 $PM_{2.5}$ NAAQS. Any areas not meeting that deadline can request a 5-year extension to December 2019.

Further, a deadline of January 1, 2014 also provides adequate and reasonable time for sources to plan for compliance with the Transport Rule and install any necessary controls. EPA believes that this deadline is as expeditious as practicable for the installation of the controls needed for compliance (*see* further discussion in section IV.D).

[79] See section IV.D.3 for discussion of non-EGUs that were included in the CAIR NO_X ozone season trading program.

[80] Section 172(a)(2) of the Clean Air Act provides that "the attainment date for an area designated nonattainment with respect to a national primary ambient air quality standard shall be the date by which attainment can be achieved as expeditiously as practicable, but no later than 5 years from the date such area was designated nonattainment under section 7407(d) of this title, except that the Administrator may extend the attainment date to the extent the Administrator determines appropriate, for a period no greater than 10 years from the date of designation as nonattainment, considering the severity of nonattainment and the availability and feasibility of pollution control measures." Designations for the 2006 24-hour $PM_{2.5}$ NAAQS became effective on December 14, 2009.

2. Date for Prohibiting Emissions That Significantly Contribute or Interfere With Maintenance of the 1997 Ozone NAAQS

Ozone nonattainment areas must attain permissible levels of ozone "as expeditiously as practicable," but no later than the date assigned by EPA in the ozone implementation rule (40 CFR part 51). The areas designated nonattainment in 2004 with respect to the 1997 8-hour ozone NAAQS in the eastern United States were assigned maximum attainment dates corresponding to the end of the 2006, 2009, and 2012 ozone seasons. Many areas have already attained due in part to CAIR, federal mobile source standards, and other local, state, and federal measures. Those that have not yet attained the standard have maximum attainment dates ranging from 2010 (these are the 2009 areas that have been granted a 1-year extension due to clean data in 2009) to 2018. Areas designated "serious" nonattainment areas have a June 2013 maximum attainment deadline. The proposed Transport Rule's first phase of reductions in 2012 will help the remaining areas with June 2013 maximum attainment deadlines attain the 1997 8-hour ozone NAAQS by their deadline. The reductions will also improve air quality in areas with later deadlines.

3. Reductions Required by 2012 To Ensure That Significant Contribution and Interference With Maintenance Are Eliminated as Expeditiously as Practicable

EPA is requiring an initial phase of reductions by 2012. These reductions are necessary to ensure that significant contribution and interference with maintenance are eliminated as expeditiously as practicable. This will in turn assist downwind states to achieve attainment as expeditiously as practicable as required by the CAA.

Because the proposed rule, if finalized, will replace the CAIR, EPA cannot assume that after this rule is finalized, EGUs would continue to emit at the reduced emissions levels achieved by CAIR. Instead, it is the emissions reductions requirements in the proposed FIPs that will determine the level of EGU emissions in the eastern United States. For these reasons, EPA is proposing to require an initial phase of reductions by 2012 which would ensure that existing and planned SO_2 and NO_X controls operate as anticipated.

4. How Compliance Deadlines Address the Court's Concern About Timing

As directed by the Court in *North Carolina* v. *EPA,* 531 F.3d 896 (DC Cir. 2008), and described previously, EPA has established the compliance deadlines in the proposed rule based on the respective NAAQS attainment requirements and deadlines applicable to the downwind nonattainment and maintenance sites.

The 2012 deadline for compliance with the limits on ozone-season NO_X emissions is coordinated with the June 2013 maximum attainment deadline for serious ozone nonattainment areas (taking into account the need for reductions by 2012 to demonstrate attainment by that date). This deadline is also consistent with the requirement that states attain the NAAQS as expeditiously as practicable.

The 2014 deadline for compliance with the limits on annual NO_X and annual SO_2 emissions is coordinated with the April 2015 maximum attainment deadline for areas that received the maximum 5-year extension of the 5-year attainment deadline for the 1997 $PM_{2.5}$ NAAQS (taking into account the need for reductions by 2014 to demonstrate attainment by April 2015). This 2014 compliance deadline is also consistent with December 2014 attainment deadline (5 years from designation, in the absence of an extension) for areas designated nonattainment for the 2006 $PM_{2.5}$ NAAQS. Areas unable to meet this 2014 deadline may seek a maximum 5-year extension to 2019.

In addition, the 2012 compliance deadline for the first-phase of annual NO_X and annual SO_2 emissions reductions will assure the reductions are achieved as expeditiously as practicable. EPA established the interim 2012 compliance deadline for annual NO_X and annual SO_2 reductions because a significant number of reductions can be achieved by 2012. However, given the time needed to design and construct scrubbers at a large number of facilities, EPA believes the 2014 compliance date is as expeditious as practicable for the full quantity of SO_2 reductions necessary to fully address the significant contribution and interference with maintenance. Requiring reductions in transported pollution as expeditiously as practicable, as well as within maximum deadlines, helps to promote attainment as expeditiously as practicable. This is consistent with statutory provisions that require states to adopt SIPs that provide for attainment as expeditiously as practicable and within the applicable maximum deadlines.

5. EPA Will Consider Additional Reductions in Pollution Transport To Assist in Meeting Any Revised or New NAAQS

a. Ozone

As noted, in a January 19, 2010, notice of proposed rulemaking, EPA proposed to strengthen the NAAQS for ozone. In that notice, EPA proposed levels for the ozone standard to a level within the range of 0.060 to 0.070 parts per million. EPA also proposed in this same notice to establish a distinct cumulative, seasonal "secondary" standard, designed to protect sensitive vegetation and ecosystems, including forests, parks, wildlife refuges and wilderness areas.[81]

EPA expects to finalize the revised NAAQS for ozone in August 2010. After the NAAQS are finalized, EPA will be able to identify areas that are expected to have difficulty attaining and maintaining those standards and will evaluate and analyze the impact of upwind state emissions in those areas with regard to those standards. EPA has already begun the technical background work necessary to allow it to move quickly, once the revised ozone standards are promulgated, with a proposal to address upwind emissions that significantly contribute to nonattainment of or interfere with maintenance of those standards. Because that analysis will take some time, and because EPA recognizes the urgency of responding to the concerns raised by the Court in *North Carolina* v. *EPA*, EPA intends to address the requirements of 110(a)(2)(D)(i)(I) with respect to the revised ozone standards in a subsequent proposal. Addressing the 110(a)(2)(D)(i)(I) requirements for the new NAAQS shortly after promulgation of those NAAQS would help clarify the requirements related to transported emissions before downwind state nonattainment SIPs are due. In doing so, the transport rule would aid downwind states in developing plans for attaining and maintaining the new NAAQS.

b. Fine Particles

EPA is also on a schedule to review and, if necessary update the $PM_{2.5}$ NAAQS. This review is scheduled for completion in October 2011. EPA plans

[81] This proposed cumulative, seasonal standard is expressed as an annual index of the sum of weighted hourly concentrations, cumulated over 12 hours per day (8 a.m. to 8 p.m.) during the consecutive 3-month period within the O_3 season with the maximum index value, set at a level within the range of 7 to 15 ppm-hours.

to conduct background technical analyses so that EPA will be prepared to move quickly, if necessary, with a transport rule related to any revised $PM_{2.5}$ NAAQS.

D. Implementing Emissions Reductions Requirements

In this rule, EPA is proposing FIPs to eliminate the significant contribution and interference with maintenance EPA has identified in this action. We are proposing one "remedy" option to implement the necessary emissions reductions and taking comment on two other options. Before presenting these options we briefly summarize the approaches used in the NO_X SIP Call and CAIR.

1. Approaches Taken in NO_X SIP Call and CAIR

In the NO_X SIP Call and CAIR, EPA developed emissions trading programs as possible remedies to 110(a)(2)(D)(i)(I) SIP deficiencies. States covered by the rules were given the option of joining the trading programs and EPA determined that, by doing so, they would satisfy the requirements of 110(a)(2)(D)(i)(I) with respect to specific NAAQS. The NO_X SIP Call provided an ozone-season NO_X trading program and addressed the requirements of the ozone NAAQS only. The CAIR provided SO_2, annual NO_X, and ozone-season NO_X trading programs, and addressed both the 1997 ozone and the 1997 $PM_{2.5}$ NAAQS.

NO_X SIP Call approach. The NO_X SIP Call proposed a regional cap and trade program as a way to make cost-effective NO_X reductions. Created after years of scientific research and air quality data analyses showed that upwind NO_X emissions can contribute significantly to ozone nonattainment in downwind states, the NO_X Budget Trading Program (NBP) followed several other major efforts to reduce NO_X from large, stationary sources. These initiatives included the Acid Rain Program, OTC NO_X Budget Program, New Source Review, New Source Performance Standards, application of Reasonably Available Control Technology to existing sources, and other state efforts.

By notice dated October 27, 1998 (63 FR 57356), EPA took final action to require states to prohibit specified amounts of emissions of one of the main precursors of ground-level ozone, NO_X, in order to reduce ozone transport across state boundaries in the eastern half of the United States. EPA found that sources in 23 states emit NO_X in amounts that significantly contribute to nonattainment of the 1-hour ozone NAAQS in downwind states. EPA set forth requirements for each of the affected upwind states to submit SIP revisions prohibiting those amounts of NO_X emissions that significantly contribute to downwind air quality problems. EPA established statewide NO_X emissions budgets for the affected states. States had the flexibility to adopt the appropriate mix of controls for their state to meet the NO_X emissions reductions requirements of the SIP call.

In the final regulation, EPA offered to administer a multi-state NO_X Budget Trading Program for states affected by the NO_X SIP Call. The NO_X Budget Trading Program was an ozone season (May 1 to September 30) cap and trade program for EGUs and large industrial combustion sources, primarily boilers and turbines. The program used a regionwide cap for ozone season NO_X emissions. The cap was the sum of the state emissions budgets established by EPA under the NO_X SIP Call regulation to help states meet their SIP obligations. Authorizations to emit, known as allowances, were allocated to affected sources based on state trading budgets. The NO_X allowance market enabled sources to trade (buy and sell) allowances throughout the year. Sources could reduce NO_X emissions in any manner. Options included adding emissions control technologies, replacing existing controls with more advanced technologies, optimizing existing controls, or switching fuels. At the end of every ozone season, each source surrendered sufficient allowances to cover its ozone season NO_X emissions (each allowance represents one ton of NO_X emissions). This process is called annual reconciliation. If a source did not have enough allowances to cover its emissions, EPA automatically deducted allowances from the following year's allocation at a 3:1 ratio. If a source had excess allowances because it reduced emissions beyond required levels, it could sell the unused allowances or bank (save) them for use in a future ozone season. To accurately monitor and report emissions, sources use continuous emission monitoring systems (CEMS) or other approved monitoring methods under EPA's stringent monitoring requirements (Title 40 of the Code of Federal Regulations [CFR], Part 75).

The NO_X SIP Call cap and trade program was a way to make cost-effective NO_X reductions. Under the NO_X SIP Call, states had the flexibility to determine the mix of controls to meet their emissions reductions requirements. However, the rule provides that if the SIP controls EGUs, then the SIP must establish a budget, or cap, for EGUs. The EPA recommended that each state authorize a trading program for NO_X emissions from EGUs. Each of the states required to submit a NO_X SIP under the NO_X SIP Call chose to adopt the cap and trade program regulating large boilers and turbines. Each state based its cap and trade program on a model rule developed by EPA. Some states essentially adopted the full model rule as is, while other states adopted the model rule with changes to the sections that EPA specifically identified as areas in which states may have some flexibility. The NO_X SIP Call cap and trade program, modeled closely after the OTC NO_X Budget Program, was phased in starting in 2003 for the OTC states, with the majority of affected states participating as of 2004.

CAIR Approach. In May 2005, EPA promulgated CAIR to address emissions in 28 states and the District of Columbia that it found contribute significantly to nonattainment of the 1997 $PM_{2.5}$ and 8-hour ozone NAAQS in downwind states. The EPA required these upwind states to revise their SIPs to include control measures to reduce emissions of SO_2 and/or NO_X. Reducing upwind precursor emissions helps the downwind $PM_{2.5}$ and 8-hour ozone nonattainment areas achieve the NAAQS. Moreover, reducing upwind emissions makes it possible for attainment to be achieved in a more equitable, cost-effective manner than if each nonattainment area attempted to achieve the NAAQS by implementing local emissions reductions alone.

In CAIR, EPA offered states optional regionwide cap and trade programs, which were similar to the SO_2 trading program in Title IV of the CAA and the NO_X Budget Trading Program in the NO_X SIP Call. CAIR required implementation of emissions reductions requirements for SO_2 and NO_X in two phases. The first phase of NO_X reductions started in 2009 (covering 2009–2014) and the first phase of SO_2 reductions began in 2010 (covering 2010–2014); the second phase of reductions for both NO_X and SO_2 would start in 2015 (covering 2015 and thereafter). The required emissions reductions requirements are based on controls that are known to be highly cost effective for EGUs. CAIR also included model rules for multi-state cap and trade programs for annual SO_2 and NO_X emissions for $PM_{2.5}$, and seasonal NO_X emissions for ozone, that states could choose to adopt to meet the required emissions reductions in a flexible and cost-effective manner. The CAIR provided for the NO_X SIP Call cap and trade program to be replaced by the

CAIR ozone season NO_X trading program.

The U.S. Court of Appeals granted several petitions for review of the CAIR and remanded the rule to EPA. Because the Court decided to remand the rule without vacatur, however, CAIR remains in effect. This proposed rule would replace the CAIR upon final promulgation.

2. Judicial Opinions

Challenges to both the NO_X SIP Call and the CAIR were brought before the U.S. Court of Appeals for the DC Circuit. In *Michigan* v. *EPA*, 213 F.3d 663, the Court largely upheld the NO_X SIP Call. The portion of this opinion most directly related to the remedy selected by EPA, discusses EPA's decision to utilize a uniform control strategy. The Court rejected two specific challenges to the requirement that "all covered jurisdictions, regardless of amount of contribution, reduce their NO_X by an amount achievable with "highly cost-effective controls." *Id.* at 679. EPA's approach, Petitioners first alleged, was irrational because it did not take into account differences in individual states" respective contributions to downwind nonattainment. Both small and large contributors were required to make reductions achievable by the application of highly cost effective controls. The court rejected this challenge finding that this result "flows ineluctably from EPA's decision to draw the 'significant contribution' line on the basis of cost differentials." *Id.*

Petitioners' second objection to the use of uniform controls was that it failed to take into account the fact that the location of emissions reductions may affect the impact of those reductions on downwind nonattainment areas. Petitioners argued that because reductions closer to the nonattainment area have a greater benefit, EPA's use of a highly-cost-effective standard and region-wide emissions trading did not guarantee that it would have secured the rule's health benefits at the lowest cost. *See id.* The Court rejected this challenge also, giving deference to EPA's judgment that non-uniform regional approaches would not "'provide either a significant improvement in air quality or a substantial reduction in cost.'" *Id.* (quoting 63 FR 57423).

Petitioners challenging the CAIR also raised issues related to EPA's use of an interstate trading program to satisfy the requirements of section 110(a)(2)(D)(i)(I). Petitioners challenged both the trading program itself and the state budgets. These budgets were used to determine the number of emission allowances allocated to sources in each state or, if the state chose not to participate in the trading programs, the specific emission reduction requirements for that state.

The Court concluded, in *North Carolina* v. *EPA*, 531 F.3d 896, that EPA had not demonstrated that the 110(a)(2)(D)(i)(I) remedy promulgated in CAIR would effectuate the statutory mandate of section 110(a)(2)(D)(i)(I) and promote the goal of prohibiting contributing sources within one state from contributing to nonattainment in another state. In reaching this conclusion, the Court emphasized that EPA had not adequately measured each individual state's significant contribution. *See id.* at 908. ("It is unclear how EPA can assure that the trading programs it has designed in CAIR will achieve section 110(a)(2)(D)(i)(I)'s goals if we do not know what each upwind state's "significant contribution" is to another state.")

The Court also emphasized that section 110(a)(2)(D)(i)(I) "prohibits sources '*within the State*' from 'contribut[ing] significantly to nonattainment *in* * * * *any other State* * * *'" *Id.* at 907. (quoting section 110(a)(2)(D)(i)(I) and adding emphasis). While recognizing that it was "possible that CAIR would achieve section 110(a)(2)(D)(i)(I)'s goals" it concluded that "CAIR assures only that the entire region's significant contribution will be eliminated," and that "EPA is not exercising its section 110(a)(2)(D)(i)(I) duty unless it is promulgating a rule that achieves something measurable toward the goal of prohibiting sources "within the State" from contributing to nonattainment or interfering with maintenance "in any other State." *Id.* at 907. Furthermore, since CAIR was designed as a "complete remedy to section 110(a)(2)(D)(i)(I) problems" the Court emphasized that "it must actually require elimination of emissions from sources that contribute significantly and interfere with maintenance." *Id.* at 908. In doing so, however, the Court also acknowledged that it had accepted in *Michigan* v. *EPA*, 213 F.3d 663 (D.C. Cir. 2000) EPA's decision to apply uniform emissions controls and its consideration of cost in the definition of significant contribution. *See North Carolina*, 531 F.3d at 908.

In developing options to eliminate the emissions identified as constituting all or part of a state's significant contribution and interference with maintenance, EPA has been mindful of the direction provided by the Court. As discussed in greater detail later, EPA believes that each of the remedy options presented is consistent with the Court's opinions interpreting the requirements of section 110(a)(2)(D)(i)(I).

3. Remedy Options Overview

EPA is proposing one "remedy" option to implement the emissions reductions requirements and taking comment on two alternatives. This section provides a brief overview of the proposed remedy and the two alternatives. Sections V.D.4, V.D.5, and V.D.6, later, describe the proposed remedy and the alternatives in detail.

EPA considered a full range of remedy options in developing this proposal. Among other things, EPA considered variations of direct control options, intrastate cap and trade, interstate cap and trade, hybrids of these approaches, and simple state emissions caps. Stakeholders have suggested a variety of remedy options for EPA's consideration. A TSD in the docket entitled "Other Remedy Options Evaluated" describes other options that EPA evaluated.

Based on its consideration of a range of options, EPA is proposing one remedy option and requesting comment on two alternatives. The proposed remedy option, discussed later, is a hybrid approach that combines limited interstate trading with other requirements. The alternative remedies on which EPA requests comment include an intrastate trading option and a direct control option. The proposed and alternative remedy options would regulate SO_2 and NO_X emissions from EGUs through FIPs in the covered states to eliminate or address the states" significant contribution to nonattainment in, or interference with maintenance by, downwind areas with respect to the daily and annual $PM_{2.5}$ NAAQS and the 8-hour ozone NAAQS.

The remedy option EPA is proposing would use state-specific control budgets and allow for intrastate and limited interstate trading of emissions allowances allocated to EGUs. This approach would assure environmental results while providing some limited flexibility to covered sources consistent with the Court decision as described later. The approach would also help ease the transition for implementing agencies and covered sources from CAIR to the Transport Rule. Based on consideration of a range of options, EPA believes that the proposed option is the best approach, for the reasons discussed in section V.D.4.

The Agency is also presenting other alternative remedies for comment. The first alternative for which EPA requests comment would use state-specific control budgets and allow intrastate trading of emissions allowances allocated to EGUs, but no interstate

trading. The second alternative for which EPA requests comment is a direct control program in combination with state-specific control budgets.

EPA recognizes there could be cost savings from an approach that uses aless restrictiveinterstate trading option. EPA also recognizes that unrestricted trading programs including the NO_X SIP Call Trading Program have been very successful in addressing regional pollution problems.

In this action, EPA is not proposing such an unrestricted trading program, because EPA does not believe that such an option could provide assurance that each state achieves emissions reductions within the state, as required by the *North Carolina* decision. As the D.C. Circuit emphasized in its opinion, the statutory requirement in section 110(a)(2)(D)(i)(I) aims to prohibit "sources "within the State" from contributing to nonattainment or interfering with maintenance in "any other State." *North Carolina*, 531 F.3d at 908. The location of emission reductions is relevant because it can influence where air quality improvements occur and whether a particular state meets its statutory obligations. See North Carolina, 531 F.3d at 907.

In addition to considering unrestricted trading, EPA also considered whether there were other ways that a trading program could be structured to address the Court's concerns. In particular, EPA reviewed a methodology that had been investigated during the development of the NO_X SIP Call regulation that used trading ratios ("Development and Evaluation of a Targeted Emission Reduction Scenario for NO_X Point Sources in the Eastern United States: An Application of the Regional Economic Model for Air Quality (REMAQ)", Prepared by Stratus Consulting inc. November 24, 1999) (at *http://www.epagov/airtransport*). This approach would allow interstate trading, but use trading ratios to take into account differences in the cumulative downwind impact of emissions from different states. Trading ratios would be developed for each pair of states using air quality modeling such that, given the meteorological assumptions underlying the air quality modeling, the ratios would represent the ratio of the benefit to downwind air quality within a region from controlling emissions in different upwind areas. For instance, in its simplest form, if emission reductions from State A were twice as effective at reducing cumulative downwind air quality impact on a set of downwind receptors as emission reductions from State B, the trading ratio between States A and B would be 2 to 1.[82] In other words, if the States chose to trade, State A would have to purchase 2 allocations from State B to cover 1 ton of State A's emissions, since State A's emissions have twice the impact on downwind air quality. Such an approach offers the very valuable potential to address the transport problem in an effective (and potentially less costly) manner, as it incentivizes reductions from the places where they have the greatest value in reducing downwind air quality problems. While it offers such opportunities, there are challenges in developing such a system that is consistent with the requirement under section 110(a)(2)(D) that emission reductions occur in particular geographic locations. The trading ratio approach would be designed to assure a cumulative downwind air quality result, not to assure specific upwind reductions. Although it would reduce the incentive for sources from upwind states with larger cumulative impacts to comply by purchasing allowances (since they would need to purchase a greater number of allowances per ton emitted than sources in states with less of an impact), as currently contemplated it would not be possible under this approach to include enforceable legal requirements to ensure that a specific state's emissions remain below a specified level or to ensure that a specific amount of reductions occur within a particular state. EPA specifically requests comment on whether a ratios trading program could be designed to provide such a legal assurance. We also seek comment on whether such an assurance would be needed if, for example, in practice modeling results predicted with confidence that sufficient state-by-state reductions would be achieved under such an approach.

In the SIP Call, EPA did not ultimately propose this methodology for several reasons. First, the Stratus Consulting study ("Development and Evaluation of a Targeted Emission Reduction Scenario for NO_X Point Sources in the Eastern United States: An Application of the Regional Economic Model for Air Quality (REMAQ)") estimated that the most significant cost savings occurred from moving from a uniform direct control approach to a conventional cap-and-trade approach (the study suggested that this would lead to cost savings of approximately 25 percent). Adding trading ratios added significant complexity while only very slightly lowering costs (1 percent to 5 percent compared to conventional cap and trade, where the cost savings decreased as the problem being addressed became more widespread (*e.g.* cost savings for the more stringent 1997 8 hour ozone NAAQS standard would be less than cost savings for the less stringent early 1 hour standard)) (Stratus, page s–2). However, because the transport rule is a larger program covering multiple pollutants with a different set of non-attainment areas and a broader geographic scope, there is the potential for greater cost savings. Second, the trading ratios are dependent upon the meteorological assumptions used to develop them; to the extent that future year meteorology or costs turn out to be different, the trading ratios could in fact lead to less than predicted downwind air quality benefits. Notably in reality, the ratios would have to consider that the upwind states that impact a downwind receptor vary from receptor to receptor; conversely each upwind state contributes to different sets of downwind receptors. It would be very challenging to develop trading ratios that account for this myriad of different relationships. EPA believes these concerns are also valid in the context of this Transport Rule.

In addition, in considering this approach in the original SIP Call, it took close to a year to perform the underlying analysis to develop ratios for 1 pollutant (NO_X) and one downwind air quality problem (ozone). In this context, there are 3 pollutants (annual NO_X, annual SO_2 and ozone season NO_X) and two downwind air quality problems (ozone and $PM_{2.5}$) to consider.

EPA requests comment on the trading ratios approach, including whether: The trading ratio approach described above would be consistent with the Court opinion in *North Carolina* v. *EPA* and satisfy the section 110(a)(2)(D) requirement that reductions occur "within the state"; there are ways the approach could be modified to be consistent with the Court opinion and the statutory requirement; there are ways that such an approach could administratively be put in place by 2012 and be modified and adopted if further reductions are required to address

[82] Note that the report evaluating this alternative was a theoretical economic and air quality analysis of the concept. It did not explore how trading ratios would be incorporated into a workable trading program. It did however indicates that the "approach also provides for the possibility that the emission weights developed by this analysis could be incorporated into an emission trading program in which emission weights act like exchange rates between different subregions and species. However this adds a significant increase in the complexity of the market and in practical terms is worth considering only when the potential cost savings are large enough to offset the additional complexity in market structure." P. 1–7, Stratus Consulting Inc. November 24, 1999.

future NAAQS; and on whether there are ways that such a system could be designed to be transparent and relatively simple for sources to understand and comply with.

Analysis from the SIP Call suggests that the trading ratios approach might have the potential to slightly reduce costs. However, the approach, as envisioned, appears to be in tension with EPA's mandate under section 110(a)(2)(D)(i)(I) to assure that significant contribution is fully addressed in each upwind state. While such an approach would ensure reductions on a region-wide basis, EPA has not been able to identify a way that the trading ratio approach could be modified to assure a specific set of downwind emissions reductions from all states. Under such an approach, there is the potential that some upwind states might make reductions that are larger than their significant contribution, while other states might make reductions that are less than their significant contribution. Because the state budgets have been designed to achieve all reductions available at a given cost, trading ratios other than one to one, although providing equivalent improvements in downwind air quality would lead to emissions reductions that were inconsistent with the initial budgets.[83]

Because EPA recognizes the potential cost savings and potential improvements in program effectiveness associated with less restricted trading options, EPA is also requesting comment on the appropriateness of the assurance provisions that have been proposed, including whether they are adequate to assure that significant contribution and interference with maintenance are addressed in each state, whether they are overly restrictive, and whether there are less restrictive options that would provide adequate assurance that the statutory mandate is satisfied while providing more flexibility. Alternative approaches could potentially include: Using the basic methodology proposed with a higher or lower variability limitation or using an alternative to the approach to assure that state emissions budgets are met (*e.g.,* trading ratios designed to assure that certain upwind emission reduction targets are met, rather than trading ratios designed to assure that downwind air quality goals are met). With regards to the variability limits that EPA has proposed, EPA takes comment on alternative approaches to calculating those limits, such as considering confidence intervals different than a 95 percent confidence interval such as a 99 percent confidence interval (For more information see TSD, "Power Sector Variability".)

EPA specifically requests that any commenter suggesting a less restrictive approach address how the commenter's preferred approach would satisfy the statutory mandate in section 110(a)(2)(D)(i)(I) of the Clean Air Act and be consistent with the decision of the DC Circuit in *North Carolina* v. *EPA*, 531 F.3d 8906 (2008) (*e.g.,* if commenters suggest a higher variability limitation, what would be the rationale for allowing that amount of variability; if commenters suggest an alternative framework, how would that framework assure that reductions occur "within the state") as well as how EPA could develop the approach in a way that would be workable for sources, states, and EPA in time to achieve emission reductions in 2012 (*e.g.,* would an approach with trading ratios impact transaction costs or be overly complex for less sophisticated trading entities, can the analysis needed to develop the approach be completed in a timely way).

As discussed in section IV.E, EPA is proposing new state budgets developed on a different basis from the CAIR budgets. The intrastate and interstate trading remedy options would use new allowance allocations, also developed on a different basis from the CAIR FIP allowance allocations. *See* section IV for the proposed state budget approach and section V.D.4 for proposed allowance allocation approaches.

As discussed in section IV.F, EPA believes that inherent variability in power system operations affects each state's baseline emissions and thus also affects a state's emissions after elimination of all significant contribution and interference with maintenance. Thus, emissions may vary somewhat after implementation of the remedies under consideration. This includes the proposed remedy option (State Budgets/Limited Trading), the intrastate trading alternative, and the direct control alternative. Sections V.D.4, V.D.5, and V.D.6 describe variability approaches for the proposed remedy and each of the alternative remedies.

EPA also considered only establishing state emissions caps. Such an approach would define what must be done to eliminate all (or in some cases part) of each state's significant contribution and interference with maintenance, but it would not implement specific requirements to eliminate those emissions. As described in section III.C in this preamble, EPA decided to implement the emission reduction requirements through FIPs. To do so, EPA recognized that it needed to do more than establish simple state emissions caps. For this reason, EPA rejected the simple state emission cap option.

As with any FIP that EPA issues, a covered state may submit, for review and approval, a state implementation plan (SIP) that replaces the Federal requirements with state requirements that would achieve the required reductions. A state's SIP submission to replace the Transport Rule FIP might propose to use any remedy of the state's choosing that actually eliminates the emissions that significantly contribute to nonattainment or interfere with maintenance downwind. Section VII in this preamble further discusses SIP submissions.

4. State Budgets/Limited Trading Proposed Remedy

In this action, EPA is proposing FIPs that would establish state-specific emission control requirements using state budgets starting in 2012 in 32 states.[84] This remedy option would allow unlimited intrastate trading and limited interstate trading to account for variability in the electricity sector, but also includes assurance provisions to ensure that the necessary emissions reductions occur within each covered state. The assurance provisions, described later in this section, would restrict EGU emissions within each state to the state's budget with the variability limit and would ensure that every state is making reductions to eliminate the portion of significant contribution and interference with maintenance that EPA has identified in today's action. EPA is proposing to impose these assurance provisions starting in 2014. State-specific emissions budgets with variability limits would be established as described in section IV in this preamble. These budgets without the variability limits would be used to determine the number of emissions allowances allocated to sources in each state: An EGU source would be required to hold one allowance for every ton of

[83] EPA, however, has proposed variability limits to these budgets, and it is possible a ratios approach may imply emissions would fall within the variability limits if the ratios ultimately turned out to be close to one-to-one.

[84] The 32 states are: Alabama, Arkansas, Connecticut, District of Columbia, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. As noted in section III, for purposes of this rulemaking, when we discuss "states" we are also including the District of Columbia.

SO_2 and/or NO_X emitted during the compliance period. Banking of allowances for use in future years would be allowed under the proposed remedy. For the 2012–2013 transition period, EPA is proposing the State Budgets/Limited Trading remedy without assurance provisions. EPA is taking comment on all aspects of, as well as alternatives to, this option that address the requirements of 110(a)(2)(D)(i)(I) for prohibiting emissions that significantly contribute to or interfere with maintenance of the NAAQS in downwind states.

a. Description of the Proposal

The proposed FIPs would address the elimination of significant contribution and interference with maintenance by 2014. A first phase of reductions would be required by 2012 to assure that significant contribution and interference with maintenance are eliminated as expeditiously as practicable.

To directly eliminate the portion of each state's significant contribution and interference with maintenance that EPA has identified in this action, the proposed remedy utilizes the state budgets with variability limits described in section IV. The budgets without variability limits are used to determine the number of allowances issued to sources in each state. Each affected source must hold, and surrender to EPA, allowances equal to its emissions during the compliance period. In addition, assurance provisions under the proposed remedy cap each state's EGU emissions at a state-specific budget with a variability limit to ensure that every state actually reduces, within the state, all emissions necessary to eliminate the portion of its significant contribution and interference with maintenance that EPA has identified in today's proposal.

For the 2012–2013 transition period, EPA is taking comment on whether the assurance provisions used to limit interstate trading are needed, since the state-specific budgets are based on known air pollution controls and thus a high level of certainty exists about where reductions will occur. As described later, the proposed FIPs include penalty provisions that are adequate to ensure that the budget including a variability limit will not be exceeded so that each state eliminates the portion of its significant contribution and interference with maintenance that EPA has identified in today's proposed action.

The proposed remedy establishes four interstate trading programs starting in 2012: Two for annual SO_2, one for annual NO_X, and one for ozone season NO_X. One SO_2 trading program is for sources in states (referred to as the SO_2 group 1) that need to make more aggressive reductions to eliminate the portion of their significant contribution that EPA has identified in today's proposed action, while the second is for sources in states (referred to as SO_2 group 2) with less stringent reduction requirements. States within SO_2 group 1 can trade SO_2 allowances only with other states in that group. Similarly, states within SO_2 group 2 can trade SO_2 allowances only with other states in that group. Note that all states covered for annual NO_X may trade with each other, even if they are in different groups for SO_2. Table IV.D.5 in section IV, previously, summarizes the respective covered states for the SO_2 group 1, SO_2 group 2, and annual NO_X trading programs; Table IV.E–2 lists the states for the ozone season NO_X program.

New emissions allowances based on the new state budgets without variability would be allocated to individual sources, as described later. Four sets of allowances would be allocated, one for each of the four trading programs (SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season). This allocation methodology neither uses heat input adjusted by fuel factors, nor relies on the allocation of allowances under Title IV of the Act.

Sources would be allowed to trade allowances. However, the assurance provisions would limit total emissions from each state, restricting the variability of emissions from any particular state to the variability associated with its baseline emissions prior to the elimination of all or part of the state's significant contribution or interference with maintenance.

Allowance banking is permitted. Banking (or saving) allowances for future use in any given year allows sources flexibility in compliance planning. Banking lowers costs and helps reduce market volatility. Banking also acts as an incentive to reduce emissions early and accumulate allowances that can be used for compliance in future periods. Because the early reductions encouraged by the ability to bank allowances would result in the reduction of emissions below allowable levels earlier than required, the environmental and human health benefits of the reductions would accrue sooner.

b. How the Proposal Would Be Implemented

(1) Applicability

The requirements in the proposed FIPs would apply to large EGUs. Specifically, a covered source would be any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion device, a generator with nameplate capacity of more than 25 MWe producing electricity for sale. The term "fossil fuel" is defined as including natural gas, petroleum, coal, or any form of fuel derived from such material. This is the same definition that was used in CAIR and would include all material derived from natural gas, petroleum, or coal, regardless of the purpose for which such material is derived. For example, with regard to consumer products that are made of materials derived from natural gas, petroleum, or coal, are used by consumers and then used as fuel, these materials in the consumer products would qualify as fossil fuel.

Certain cogeneration units or solid waste incinerators otherwise covered by this general category of covered units would be exempt from the FIP requirements. These proposed applicability requirements are essentially the same as those in the CAIR model trading rules and CAIR FIPs (reflecting the revised cogeneration unit definition promulgated in October 2007 (72 FR 59195; October 19, 2007)), with some technical corrections to the exemptions.

Cogeneration unit exemption. In order to meet the proposed definition of "cogeneration unit," a unit (*i.e.*, a boiler or combustion turbine) must operate as part of a "cogeneration system," which is defined as an integrated group of equipment at a source (including a boiler or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. In order to qualify as a cogeneration unit, a unit also must meet, on an annual basis, specified efficiency and operating standards, *e.g.,* the useful power plus one-half of useful thermal energy output of the unit must equal no less than a certain percentage of the total energy input, useful thermal energy must be no less than a certain percentage of total energy output, and useful power must be no less than a certain percentage of total energy input. Total energy input includes all energy input except from biomass.

These proposed elements of the "cogeneration unit" definition are very similar to the definition used in CAIR. However, there are two technical differences. First, under the definition used in CAIR to qualify as a "cogeneration unit," a unit had to meet

the efficiency and operating standards every year starting with the first 12-months during which the unit produced electricity. In contrast, under the definition proposed here, a unit can qualify as a "cogeneration unit" if it meets the efficiency and operating standards every year starting the later of November 15, 1990 or the date on which the unit first produces electricity. EPA believes this definition of "cogeneration unit" is preferable because it may be problematic to obtain sufficiently detailed information about unit efficiency and operations for some units (*e.g.*, old units that may have started producing electricity many years ago). This approach is also more consistent with the approach taken in the general applicability criteria. EPA requests comment on whether it may also be problematic to obtain sufficiently detailed information about unit efficiency and operation back to November 15, 1990 and whether the efficiency and operating standards should be limited to even more recent years by requiring that the standards be met every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.,* 2000, 2005, or 2009) or the date on which the unit first produces electricity. Second, in CAIR, each unit had to meet individually the efficiency standard (i.e., the requirement that useful thermal or electrical output be at least a specified percentage of energy input). In contrast, under the "cogeneration unit" definition proposed here, if the cogeneration system of which a topping-cycle unit (where power is produced first and then useful thermal energy is produced using the resulting waste energy) is a part meets the efficiency standard on a system-wide basis, then the unit is also deemed to meet that efficiency standard. EPA believes this definition is preferable because it addresses cases where one unit in a cogeneration system is operated at a lower efficiency (*e.g.*, as a "swing" unit whose use varies with demand) to allow the rest of the units in the cogeneration system to operate with higher efficiency. EPA requests comment on whether this approach should also be applied to bottoming-cycle units (where useful thermal energy is produced first and then useful power is produced using the resulting waste energy).

As discussed previously, the operating and efficiency standards in the "cogeneration" definition must be met every year. However, EPA is concerned whether these annual standards should be applied to a calendar year when the unit involved did not operate at all. For such a year, the unit would be unable to meet the operating and efficiency standards but also would not have any emissions. EPA therefore requests comment on whether it should exclude, from the requirement to meet the operating and efficiency standards, calendar years (if any) during which a unit does not operate at all.

If a unit meets the definition of cogeneration unit (including the efficiency and operating standards), then it may qualify for the proposed cogeneration unit exemption depending on whether it meets additional criteria concerning the amount of electricity sales from the unit. In order to qualify for the exemption, a cogeneration unit would need to supply in any calendar year—starting the later of November 15, 1990 or the start-up of the unit's combustion chamber—no more than one-third of its potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. EPA requests comment on whether it may be problematic to obtain sufficiently detailed information about the disposition of a unit's generation (*e.g.*, how much was used on site or by an industrial host and how much was supplied to a utility distribution system for sale) back to November 15, 1990 and whether the electricity sales limit should be restricted to more recent years by requiring that the limit be met every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.*, 2000, 2005, or 2009) or the start-up of a unit's combustion chamber.

Solid waste incineration unit exemption. The proposed FIPs also include an exemption for solid waste incineration units commencing operation before January 1, 1985, for which the average annual fuel consumption of non-fossil fuels during 1985–1987 exceeded 80 percent and, during any three consecutive calendar years after 1990, the average annual fuel consumption of non-fossil fuels exceeds 80 percent, on a Btu basis. With regard to a solid waste incineration unit commencing operation on or after January 1, 1985, EPA proposes that the unit would be exempt if its average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation and for any 3 consecutive calendar years, thereafter, does not exceed 80 percent. This is the same as the solid waste incineration unit exemption used in CAIR. EPA requests comment on whether it may be problematic to obtain sufficiently detailed information about unit operation potentially as far back as 1985–1987 and 1990 and whether the fuel consumption standard for each unit should be limited to more recent years by requiring that the standard be met every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.*, 2000, 2005, or 2009) or the date on which the unit first produces electricity.

Further, analogous to the approach proposed for the cogeneration unit exemption, the proposed solid waste incineration unit exemption would apply to units that qualify as solid waste incineration units every year starting the later of November 15, 1990 or the date the unit first produces electricity. EPA requests comment on whether it may be problematic to obtain sufficiently detailed information about whether a unit qualified as a solid waste incineration unit back to November 15, 1990 and whether the qualification requirement should be restricted to more recent years by imposing the qualification requirement every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.*, 2000, 2005, or 2009) or the date of unit first produces electricity.

EPA also proposes to make explicit in the FIPs an interpretation that the Agency adopted in applying CAIR, namely that—solely for purposes of applying the fossil-fuel use limitation in the solid waste incineration unit exemption—the term "fossil fuel" is limited to natural gas, petroleum, coal, or any form of fuel derived from such material "for the purpose of creating useful heat." For example, this means that consumer products made from natural gas, petroleum, or coal are not fossil fuel, for purposes of determining qualification under the limitation on fossil-fuel use, because the products (*e.g.*, tires) were derived from natural gas, petroleum, or coal in order to meet certain consumer needs (*e.g.*, to meet transportation needs), not in order to create fuel (*i.e.*, material that would be combusted to produce useful heat).

Opt-in units. EPA proposes to include, in the trading programs under the proposed FIP, provisions allowing non-electric generating (non-covered) units to opt into one or more of the proposed trading programs. EPA is proposing opt-in provisions since they could encourage emission reductions by sources that could make lower cost emissions reductions than electric generating units. These lower cost reductions could replace higher cost reductions that would otherwise be required by some electric generating units and could reduce overall program costs.

Specifically, the proposed opt-in provisions would allow a non-covered unit to enter a proposed trading program voluntarily and obtain an allocation of

allowances reflecting the unit's emissions before opting in. Once in the program, the unit could make emissions reductions at a lower cost than other units in the program and then sell, to covered sources for use in compliance, allocated allowances that are in excess of the unit's reduced emissions. The allowances created for and allocated to the opt-in unit would be in addition to the allowances issued from the state budget and would be usable in compliance by any covered unit (or opt-in unit) just like the allowances allocated from the state budget to covered sources. Replacing higher cost reductions by covered units by lower cost reductions by opt-in units could reduce the overall cost of controlling emissions. EPA requests comment on the benefits and concerns of including opt-in provisions.

The proposed opt-in provisions would establish the following procedures, which are similar to those set forth in the CAIR FIPs. A unit would be eligible to opt into one of the proposed trading programs if the unit: (1) Is an operating boiler, combustion turbine, or other stationary combustion device; (2) is in a facility that is located in a state subject to that proposed trading program; (3) vents all its emissions through a stack or duct; and (4) would be able to meet the monitoring, reporting, and recordkeeping requirements for covered units under the proposed trading program. The owners and operators, through a designated representative, of a source with a unit seeking to opt in would submit to EPA an opt-in application, which must include an emissions monitoring plan for the unit. If EPA approved the monitoring plan, the unit would operate, monitor, and report emissions in accordance with the monitoring plan and monitoring and reporting requirements under Part 75, for at least one or for up to 3 full calendar years (or full ozone seasons, in the case of an opt-in unit in the proposed NO_X ozone season trading program). The unit's monitored heat input and emissions rate for that period would be the baseline heat input and baseline emissions rate used in calculating any future opt-in allowance allocations.

After the monitoring period, EPA would review the opt-in application and either approve the application (including an allowance allocation for the first year of approved opt-in status), effective January 1 (May 1 for the NO_X ozone season program) of the year of the approval, or disapprove the application. By December 1 (September 1 for the NO_X ozone season program) of the first year and each subsequent year, EPA would calculate and record the opt-in unit's allowance allocation for the year. The allowance allocation for the year involved would be the product of: The lesser of the baseline heat input and the opt-in unit's actual heat input during the control period in the immediately preceding year; and the lesser of the baseline emissions rate multiplied by 70 percent and the most stringent state or federal emissions limitation applicable to the unit (or emissions levels resulting from the imposition of Clean Air Act requirements) any time during the control period in the year involved.

After the opt-in unit was in the program for at least four years, the owners and operators could request to withdraw the opt-in unit at the end of a control period if the unit met the requirement to hold allowances covering emissions for that control period and if any allowances already allocated for a subsequent control period were surrendered. However, the owners and operators could not submit a new opt-in application for the withdrawn unit until at least 4 years after the last control period before the withdrawal. An opt-in unit that had a change in regulatory status during a control period and would then meet the general applicability requirements for covered units would immediately lose its status as an opt-in unit. Having lost its opt-in unit status, the unit would have to surrender to EPA the allocated opt-in allowances attributable to the portion of any control period during which the unit no longer qualified as an opt-in unit.

In addition to a general request for comment on all aspects of this opt-in requirement, EPA requests comment on three specific aspects of the proposed opt-in provisions. First, EPA requests commenters to explain how much interest they believe owners and operators of noncovered sources would have in using these proposed provisions to opt into one or more of the proposed trading programs and what types of sources would be most likely to opt in. Commenters on this aspect of the proposed provisions should consider what effect (if any) future emission reduction requirements under upcoming, new regulations (*e.g.*, regulations concerning maximum available control technology (MACT) standards for sources such as industrial boilers and cement kilns, best available retrofit technology (BART) requirements for certain stationary source categories, and reasonably available control technology (RACT)) might have on the pool of sources that might be interested in opting into the program. EPA notes that, in the Acid Rain Program, opt-in provisions were established in section 410 of the Act, were implemented in the Acid Rain Program regulations starting in 1995, and, to date, have been used by 4 facilities (plus 2 more facilities that temporarily opted in to obtain allowances for use in the CAIR SO_2 trading program). In the NO_X Budget Trading Program, EPA promulgated opt-in provisions that states could include in their SIPs and that were used by 3 facilities.

Second, EPA requests comment on whether it is necessary to take steps to identify in this application process whether emissions reductions identified by these facilities are reductions units would not have made for other reasons unrelated to the opt in. Comments on this issue would be especially useful if they discussed how the proposed opt-in provisions could be revised in order to ensure that opt-in units would not be credited for emissions reductions that the units would make even if they did not opt in. For example, a unit that, for business or other reasons, was already planning to take actions that would have the effect of reducing emissions (*e.g.*, fuel switching) may be able to opt in under this proposed approach and obtain allowance allocations that could be sold to covered units. In that case, emissions reductions that would have occurred anyway would be offset by the allocation of new, opt-in allowances that would be in addition to the state budget. The net result, in that case, would be an increase in total emissions—considering the emissions of both the covered units and the opt-in unit—over what total emissions would have been if the unit had not opted in. EPA requests comment on whether, in that circumstance the total emissions reduction still may be sufficient to satisfy the interstate transport issue if such reductions were not anticipated in state budgets. In other words, even if emissions reductions would have happened in the absence of the program, they may still be reductions that alleviate attainment or maintenance issues in downwind states. Third, EPA requests comment on whether the baseline emission rate used to determine the allocations for each opt-in unit should be multiplied by 70 percent before EPA compares that rate to the unit's most stringent applicable emissions limitation in order to determine which is lower. The lower emission rate would then be used in calculating the opt-in unit's allocation. EPA also requests comment on whether the allocation for an opt-in unit during Phase II of the proposed SO_2 Group 1

trading program should be reduced by 45 percent, reflecting the average percent reduction in state SO_2 Group 1 budgets from Phase I to Phase II. The 70 percent reduction of the baseline emission rate for all opt-in units, and the further 45 percent reduction in Phase II allocations for SO_2 Group 1 opt-in units, would be meant to ensure that opt-in facilities install controls in a similar manner as covered units; however, all things equal, this may serve to lower the number of facilities that would opt into the program. EPA therefore specifically solicits comment on whether the proposed 70 percent reduction (or some other percentage reduction or no reduction) should applied to the baseline emission rate for all opt-in units and on whether any additional percentage reduction or 45 percent or some other additional percentage reduction should be applied to SO_2 Group 1 opt-in units on Phase II in order to strike a reasonable balance between achieving additional reductions per opt-in facility and having more facilities opt in.

Sources equal to or less than 25 MWe and Non-EGUs. Certain smaller EGUs and non-EGU sources that were included in the NO_X Budget Trading Program were brought into the CAIR NO_X ozone season trading program. For treatment of such sources in the proposed FIPs, see section V.F in this preamble.

In the Northeast, a large number of EGUs serving generators with a nameplate capacity equal to or less than 25 MWe contribute NO_X emissions to ozone problems on high electric demand days. There is regional interest in lowering the 25 MWe applicability threshold in the ozone season to deal with this issue and in potentially requiring these units to operate with greater controls than a trading program would necessitate. EPA requests comment on lowering the greater-than-25 MWe applicability threshold for EGUs during the ozone season, and whether a trading program offers the right approach for addressing NO_X emissions from these smaller EGUs.

(2) Allocation of Emissions Allowances

EPA proposes to distribute, to sources in each state, a number of emissions allowances equal to the SO_2, annual NO_X, and ozone-season emissions budgets for that state identified in section IV.E (the state budgets listed in IV.E are the budgets without accounting for variability). As discussed later, EPA proposes to set aside 3 percent of each state's emissions budgets for new units. Tables IV.E.–1 and IV.E.–2 in section IV.E, referenced previously, show the permanent SO_2, NO_X, and ozone season NO_X budgets for each covered state (without accounting for variability). EPA would distribute four discrete types of emissions allowances for four separate cap and trade programs: SO_2 group 1 allowances, SO_2 group 2 allowances, NO_X annual allowances, and NO_X ozone season allowances.

In the SO_2 group 1 and SO_2 group 2 programs, each SO_2 allowance would authorize the emission of one ton of SO_2 annually. In the NO_X annual program, each NO_X annual allowance would authorize the emission of one ton of NO_X annually. In the NO_X ozone season program, each NO_X ozone season allowance would authorize the emission of one ton of NO_X during the regulatory ozone season (May through September for this proposed rule). Note that, as explained in section IV.E, EPA is taking comment on extending the ozone season for this rule.

In each of the four trading programs, a covered source would be required to hold sufficient allowances to cover the emissions from all covered units at the source during the control period. EPA proposes to assess compliance with these allowance-holding requirements at the source (*i.e.*, facility) level.

This section explains how EPA proposes to allocate to two sets of units in a state, existing units and new units. This section also describes the new unit set asides in each state, allocations to units that are not operating, and the recording of allowance allocations in facility accounts.

EPA proposes to base allocations to existing units on projected emissions from these units after elimination of some or all significant contribution and interference with maintenance (*i.e.*, projected emissions after implementation of the proposed FIPs), and after deductions for the new unit set asides. Section IV.E describes how EPA developed the overall state budgets.

EPA requests comment on all aspects of the allocation method, such as the overall state budgets, the need to have existing unit and new unit allowance allocations, the proposed allocation methodology for existing units, and the proposed allocation methodology for new units. EPA believes the proposed approach is consistent at the state budget and unit level with the Court's direction and also addresses the new unit issue. The proposed methodology for allocating allowances does not consider heat input or fuel adjustment factors. Note that in light of the Court decision, EPA also is not proposing any allocation methodologies that rely on Title IV existing allowances.

EPA requests comment on whether there are alternative allocation methods EPA should consider that are consistent with the Court decision. EPA asks that commenters present any such approaches in detail to enable thorough evaluation and that they provide a legal analysis demonstrating how the approach is consistent with the Court's opinions and the statutory mandate of section 110(a)(2)(D).

Allocations to existing units. Existing units are units, as described in the Applicability section, previously (*see* 4.b), that commenced commercial operation, or are planned [85] to commence commercial operation, prior to January 1, 2012. EPA proposes that, for 2012, each existing unit in a given state receives allowances commensurate with the unit's emissions reflected in whichever total emissions amount is lower for the state, 2009 emissions or 2012 base case emissions projections. In either case, the allocation is adjusted downward, if the unit has additional pollution controls projected to be online by 2012. EPA proposes to use this same method to allocate allowances for each of the four trading programs (SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season). This proposed allocation method is different from the allocation method used in the CAIR.

For states with lower SO_2 budgets in 2014 (SO_2 group 1 states), each unit's allocation for 2014 and later is determined in proportion to its share of the 2014 state budget, as projected by IPM. This approach is also different from the allocation method in CAIR. Further details on the proposed allocation method for existing units can be found in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rule.

The proposed FIPs are designed to remove emissions from each upwind state that significantly contributes to nonattainment or interferes with maintenance downwind. The allocation method is consistent with the proposed approach for determining each upwind state's significant contribution and interference with maintenance (described in section IV) because the allocations would be based on the projected remaining emissions from each covered source in each upwind state after removal of the state's significant contribution and interference with maintenance.

EPA proposes to allocate to existing units one time, before the Transport

[85] Planned units, as identified in the EGU inventory and included in IPM modeling projections, comprise units that had broken ground or secured financing and were expected to be online by the end of 2011.

Rule cap and trade programs commence (*see* discussion of schedule, later). The allocations generally would be permanent (with the exception of non-operating units, discussed later) as base amounts and would not be updated. (Note that any unused new source set aside allowances would be distributed proportionally to existing units in addition to the base amount.) By not updating the allocations, EPA can allocate for several years at once, which supports the development of allowance trading markets.

The proposed unit-level allocations for existing EGUs for Phases I and II are set forth in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rule, but EPA proposes to include them in the final rule in an Appendix A to each set of trading program regulations (*i.e.*, the SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season trading programs). Because the TSD shows the proposed allocations, Appendices A in the proposed trading program regulations do not repeat the allocations and are simply reserved. The only circumstances under which allocations would not be permanent as base amounts would be if the unit in the Appendix A table turned out not to be a covered unit, or turned out not to be required to hold allowances to cover emissions, as of the first day of the control period in 2012,[86] or if the unit stops operating for three consecutive years.

Allocations to new units. EPA proposes to allocate emissions allowances to new units from new unit set-asides in each state. EPA proposes, for each of the four trading programs, to define a new unit as: Any covered EGU not listed in the table in Appendix A of the trading rule applicable to that program; any unit listed in Appendix A whose allocation is subject to the requirement that the Administrator not record the allocation or that the Administrator deduct the amount of the allocation (*see* previous discussion in footnote), or any unit listed in Appendix A that stopped operating for three consecutive years, is no longer allocated allowances as an existing unit, but resumes operation.

EPA believes it is important to have a small new unit set-aside in each state to cover new units within the budget that was set aside to address the state's significant contribution and interference with maintenance. To create new unit set-asides, EPA would distribute to existing EGUs a quantity of allowances less than the entire state emissions budgets. EPA would hold back, for the new unit set-aside for a state, 3 percent of the state budget. Three percent was established based on the total amount of new unit emissions projected for all the covered states (See "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD). In this way, new units could be allocated some allowances for their emissions, which are part of the the state's contribution to downwind nonattainment or interference with maintenance.

For every control period after the control period in which a new unit commences commercial operation or, in the case of an existing unit that did not operate for three consecutive years, resumes operation, EPA would allocate to the unit from the new unit set-asides based on the unit's reported emissions from the previous control period. EPA would not allocate to a new unit for the control period during which the unit commences commercial operation because the unit would have no actual emissions data on which to base such an allocation.

EPA proposes that, for the first control period for which the new unit wants an allowance allocation from the new unit set aside (after the first year of operation), the designated representative of the source that includes the new unit would submit to EPA a request for a new unit allocation.

For each control period, any allowances remaining in a state's new unit set-aside (after allocations are made to new units that requested allowances) would be distributed to the existing units in that state in proportion to the existing unit's original allocations. This ensures that total allocations to units in the state would equal the state budget.

For each control period, if the size of the new unit set-aside were insufficient to provide allocations for all new units requesting allowances, then allocations to all new units would be proportionally reduced.

EPA requests comment on the proposed allocation approach for new units. EPA also requests comment on alternative allocation approaches that would provide allowances to new units for the control period during which the unit commences commercial operation.

Size of new unit set asides. EPA proposes new unit set-asides that are 3 percent of the state emissions budgets. The size of the new unit set-aside would be 3 percent for the SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season trading programs, as appropriate, for each state. EPA based the size of the proposed new unit set-asides on a comparison of projected emissions from new units to projected emissions from existing units for all covered states under the proposed State Budgets/Limited Trading remedy. As noted previously, EPA proposes that after a unit is not operating for three consecutive years, the allowances that would otherwise have been allocated to that unit, starting in the seventh year after the first year of non-operation, would be allocated to the new unit set-aside for the state in which the retired unit is located. This approach would allow the size of the new unit set-asides to grow over time. Note that in EPA's analysis to determine the size of the new unit set-asides, EPA assumed that allocations for non-operating units would be allocated to the new unit set-asides after a unit had ceased operating for 3 consecutive years (see "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD). EPA requests comment on the size of the new unit set-asides.

Non-operating units. EPA proposes that, once an EGU does not operate (*i.e.*, does not combust any fuel) for 3 consecutive years, the Agency would no longer allocate allowances to the unit, starting in the seventh year after the first year of non-operation. All allowances that would otherwise have been allocated to the unit for that seventh year and every year thereafter would be allocated to the new unit set-aside for the state in which the non-operating unit is located. This would provide additional allowances for new units that may need them (*e.g.*, for new units that replace non-operating units), and reflects the fact that new unit emissions are included in the state's budget that eliminates the portion of significant contribution and interference with maintenance that EPA has identified in today's proposed action (in an average year).

EPA proposes to continue allocating allowances to non-operating units during the 3 consecutive years of non-operation plus an additional 3-year period to reduce the incentive for owners to keep units operating simply to avoid losing the allowance allocations for those units. Other options that EPA considered include continuing to allocate allowances for an unlimited period of time, or

[86] If a unit was allocated allowances but turned out not to be a covered unit or turned out not to be required to hold allowances as of January 1, 2012, then the treatment of the allocation depends on when the Administrator determines the unit is not subject to the trading program or to the allowance-holding requirement. For instance, if the allocation has not been recorded, the Administrator would not record it, and, if the allocation has been recorded and the Administrator has not completed the compliance determination process for the unit, allowances equal to the allocation would be deducted from the unit's compliance account.

immediately discontinuing allocations to such units upon the unit ceasing operation.

Continuing allocations to non-operating units has the benefit of reducing the incentive to keep units in operation that should otherwise be, for instance, permanently retired due to age and inefficiency. EPA believes there will be less incentive to continue running old, inefficient EGUs if at least some allowances would still be received after retirement. On the other hand, stopping allocations for non-operating units realigns allowance allocations with the sources that actually need such allowances. Non-operating units obviously are no longer emitting and so do not need allowances. Moreover, additional allowances may be needed for the new unit set-aside to accommodate new units coming on line in the future. Allocating allowances for a specified, but limited, period after the unit ceases operating for 3 consecutive years, as EPA proposes to do, would be a middle ground approach to this issue.

EPA requests comment on the proposed approach for allocating allowances to non-operating units. EPA requests comment on simplifying allocations by not allocating at all to non-operating units. EPA also requests comment on maintaining perpetual allocations to non-operating units, similar to the treatment of non-operating units in the title IV Acid Rain Program.

Schedule for determining and recording allowances. As discussed previously, proposed allocations for existing units are shown in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD. EPA proposes to include final allocations for existing units in the Appendix A for each proposed trading program in the final Transport Rule.

EPA proposes to record initial allowances for existing units in facility accounts by September 1, 2011, for the control periods in 2012, 2013, and 2014. EPA proposes to record allowances for existing units by July 1, 2012 and July 1 of each year thereafter, for the control periods in the third year after the year the allowances are recorded. For example, EPA would record existing unit allowances by July 1, 2012 for control periods in 2015. Recording allowances several years in advance supports the development of the allowance trading markets and provides time for covered sources to plan for compliance.

As discussed previously, EPA proposes to determine allocations to a new unit based on the unit's reported emissions the prior year. Although the last quarter of emissions data for a year must be submitted to EPA in the fourth quarterly emissions report by January 30 of the next year, the emissions data in that report may be revised based on EPA's review and may not be finalized until May or June after receipt of that report. Consequently, EPA proposes to determine new unit allocations by July 1 of the year for which the allocation is determined. (Because, for an ozone season ending September 30, emissions data may not be finalized until the following February or March, EPA proposes to determine new unit allocations by April 1.) For example, EPA would determine a new unit's allocations for control periods in 2012 by July 1, 2012. EPA proposes to make the new unit allocation determinations available to the public through a notice of data availability. Under the proposal, objections to the notice could be submitted, and EPA would issue a second notice of data availability referencing any necessary adjustments of the new unit allocations.

EPA proposes to record allowances for new units by September 1, 2012 and September 1 of each year thereafter, for the control periods in the year that the allowances are recorded. (For the units in the NO_X ozone season program, the comparable deadline for recordation of new units" allowances is June 1.) For example, EPA would record new unit allocations by September 1, 2012 for control periods in 2012.

EPA requests comment on the proposed schedule for determining and recording emissions allowances, especially administratively-practical ways to record allowances as soon as possible, so facilities have information useful in compliance planning.

Alternative allocation methods. The proposed allocation method, described previously, would determine each unit's allocation consistent with the proposed approach to determine each state's significant contribution and interference with maintenance. EPA considered other alternative allocation methods. One is discussed here, but EPA recognizes that there are many ways that allowances could be allocated. EPA is requesting comment on whether the alternative described here or any other approach should be used instead of the proposed allocation method.

As discussed in section IV, the state emissions budgets are determined based on EPA's analysis of significant contribution and interference with maintenance in each upwind state. EPA believes that it is appropriate to develop individual unit allowances consistent with this approach. In the proposed approach, EPA does this by allocating down to the individual unit level using all of the same assumptions used in developing the proposed budgets. Under this approach all units are allocated allowances consistent with their projected emissions; this means that a unit that installs control equipment receives fewer allowances than a similar unit that did not install control equipment.

EPA is taking comment on an alternative methodology that still links unit allowances directly to the way state budgets were developed (and thus, significant contribution was defined). In the alternative, all units within a state would be treated as a single group. The allocation method would distribute allowances equal to a state's emissions budget without variability to each covered source in the state (in effect, distributing the responsibility for eliminating significant contribution and interference with maintenance) based on each source's proportional share of total state heat input. The state heat input would be as projected for the initial year of the program. In other words, this alternative method for distributing allowances would have the effect of distributing the responsibility for eliminating all or part of a state's overall significant contribution and interference with maintenance to individual units based on each unit's share of projected heat input.

There are other approaches to allocation. For example, EPA could identify groups of units in each state that are capable of having similar emissions characteristics (e.g., grouped by size, fuel type, or age). EPA would distribute a state's emissions budget without variability to each group of units in the state (in effect, distributing the responsibility for eliminating all or part of significant contribution) perhaps based on each group's proportional share of the state budget as projected in the initial year of the program. After apportioning a state's budget to the groups of units, under such an approach EPA could distribute allocations to individual sources within each group based on each source's proportional share of projected heat input. Like the first alternative allocation method described previously, this approach distributes each state's significant contribution and interference with maintenance to individual sources in the state. By determining groups and then distributing allocations within the groups based on proportional shares, this approach would treat units within the categories equally (*i.e.*, it would not treat a source that had acted early to control differently from one that had yet to take control action).

EPA requests comment on the proposed allocation approach, the alternative approach, and on any other approaches that are consistent with the Court decision. EPA asks that commenters present any such approaches in detail to enable thorough evaluation and that they provide a legal analysis demonstrating how the approach is consistent with the Court's opinions and the statutory mandate of section 110(a)(2)(D).

(3) Allowance Management System

EPA proposes that the State Budgets/Limited Trading remedy include an allowance management system (AMS) operated essentially the same as the existing allowance management systems that are currently in use for CAIR and the Acid Rain Program under Title IV. Under the proposed State Budgets/Limited Trading remedy, the SO_2 programs and the NO_X programs would remain separate trading programs maintained in EPA's existing AMS. AMS would be used to track Transport Rule trading program SO_2 and NO_X allowances held by covered sources, as well as such allowances held by other entities or individuals. Specifically, AMS would track the allocation of all SO_2 and NO_X allowances, holdings of SO_2 and NO_X allowances in compliance accounts (*i.e.*, accounts for individual covered sources) and general accounts (*i.e.*, accounts for other entities such as companies and brokers), deduction of SO_2 and NO_X allowances for compliance purposes, and transfers of allowances between accounts. The primary role of AMS is to provide an efficient, automated means for covered sources to comply, and for EPA to determine whether covered sources are complying, with the emissions rate limitations and other emissions-related provisions of the cap and trade programs. AMS also allows the public to see whether sources are complying. In addition, AMS provides data to the allowance market, including a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred.

(4) Monitoring and Reporting

EPA proposes to require that Transport Rule-covered sources monitor and report SO_2 and NO_X emissions in accordance with 40 CFR part 75. Most sources that would be covered by the proposed Transport Rule are already measuring and reporting SO_2 mass emissions year round under CAIR and/or the Title IV Acid Rain Program. Similarly, most sources that would be covered are already measuring and reporting NO_X mass emissions year round under CAIR. CAIR and the Acid Rain Program both require Part 75 monitoring.

Consistent, complete, and accurate measurement of emissions, as Part 75 requires, ensures that, for a given pollutant, one ton of reported emissions from one source is equivalent to one ton of reported emissions from another source. Thus, each allowance represents one ton of emissions, regardless of the source for which the emissions are measured and reported. This establishes the integrity of each allowance, which instills confidence in the underlying market mechanisms that are central to providing sources with flexibility in achieving compliance.

EPA proposes to require monitoring of SO_2 and NO_X emissions by all existing covered sources by January 1, 2012 for states covered for the daily and/or annual $PM_{2.5}$ NAAQS, and monitoring of NO_X emissions by May 1, 2012 for sources covered for the 8-hour ozone NAAQS, using Part 75 certified monitoring methodologies. New sources would have separate deadlines based upon the date of commencement of commercial operation, consistent with CAIR and the Acid Rain Program.

Specifically, a new unit must install and certify its monitoring system within 180 days of the commencement of commercial operation. While, under the Acid Rain Program and CAIR, the deadline was the earlier of 90 operating days or 180 calendar days after commencement of commercial operation, EPA intends to propose that part 75 be revised to use only the 180-day deadline. EPA believes that using only the 180-day deadline would ensure that new units have sufficient time to complete installation and certification of monitoring systems without having to request extensions of time and would facilitate compliance by making the monitoring deadline clearer for owners and operators and easier for EPA to apply. *See* a discussion on units transitioning from CAIR and units previously not covered by Part 75 requirements in section V.F, later.

EPA also proposes to require designated representatives to submit quarterly reports that would include emissions and related data and proposes to establish a procedure for resubmission of quarterly reports where appropriate. Specifically, the proposed reporting provisions would include the same requirement to submit quarterly reports as the requirement in Part 75. In addition, the proposed provisions would include language that would make explicit a process that is implicit under, and has been in continuous use in, the Acid Rain, NO_X Budget, and CAIR trading programs. The resubmission process would be as follows. The Administrator could review and audit any quarterly report to determine whether the report met the monitoring, reporting, and recordkeeping requirements in the proposed rule and Part 75. The Administrator would provide notification to the designated representative stating whether any of these requirements was not met and specifying any corrections that the Administrator believed were necessary to make through resubmission of the report and a reasonable deadline for a response. The Administrator could provide reasonable extensions of such deadline. The designated representative would be required, within the deadline (including any extensions), to resubmit the report with the identified corrections, except to the extent the designated representative would submit information showing that a correction was not necessary because the report already met the monitoring, reporting, and recordkeeping requirements relevant to the correction. Any resubmission of a quarterly report would have to meet the requirements for quarterly report submission, except for the deadline for initial submission of quarterly reports.

(5) Assurance Provisions

To ensure that the proposed FIPs require the elimination of all emissions that EPA has identified that significantly contribute to nonattainment or interfere with maintenance within each individual state, we are proposing to establish assurance provisions, as described later, in addition to the requirement that sources hold allowances sufficient to cover their emissions. These assurance provisions limit emissions from each state to an amount equal to that state's budget with the variability limit for state budgets, discussed in section IV. As described therein, this variability limit takes into account the inherent variability in baseline EGU emissions and recognizes that state emissions may vary somewhat after all significant contribution is eliminated. This approach also provides sources with flexibility to manage growth and electric reliability requirements, thereby ensuring the country's electric demand will be met while meeting the statutory requirement of eliminating significant contribution.

Starting in 2014, EPA is proposing as part of the FIPs to establish limits on the total emissions that may be emitted from EGUs at sources in each state. For

any single year, the state's emissions must not exceed the state budget with the variability limit allowed for any single year for that state (*i.e.*, the state's 1-year variability limit). In addition, the 3-year rolling average of the state's emissions must not exceed the state budget with the variability limit allowed on average for any consecutive 3 years for that state (*i.e.*, the state's 3-year variability limit). Note that in 2014 and 2015, EPA would apply only the 1-year variability limit, and not the 3-year variability limit. Because emissions would be evaluated against the 3-year variability limit on a 3-year rolling average basis, the application of the 3-year variability limit in 2016 would serve to limit emissions in 2014 and 2015.

In other words, in addition to covered sources being required to hold allowances sufficient to cover their emissions, the total sum of EGU emissions in a particular state cannot exceed the state budget with the state's 1-year variability limit in any one year, and the state's annual average emissions for any 3-year period can not exceed, on average, the state budget with the state's 3-year variability limit. The fact of the 3-year variability limit would further assure that emissions are constrained during the two preceding years.

For example, a hypothetical state has a budget of 100,000 tons, a 1-year variability limit of 10,000 tons, and a 3-year variability limit of 5,800 tons.

- In the first year, collective emissions from covered EGUs in the state are 120,000 tons, 10,000 tons over the budget with 1-year variability limit of 110,000 tons, triggering the assurance provisions in that year.
- In the second year, collective emissions from covered EGUs in the state are 97,500 tons, below the state budget with 1-year variability limit of 110,000 tons. Assurance provisions are not triggered.
- In the third year, collective emissions from covered EGUs in the state are 109,000 tons, below the state budget with 1-year variability limit of 110,000 tons. Assurance provisions are not triggered for the 1-year variability limit. But after three years, the state emissions are computed against the 3-year variability limit. The 3-year rolling average (adding the last 3 years of emissions and dividing that by three) computes to 108,833 and determines that the 3-year variability limit of 105,800 tons is exceeded, even though in any one year, the 1-year variability limit may not have been exceeded.
- In the fourth year, collective emissions from covered EGUs in the state are 99,000 tons, below the state budget with 1-year variability limit of 110,000 tons. Assurance provisions are not triggered for the 1-year variability limit. The 3-year rolling average of the last 3 years is 101,833, which is less than the 3-year variability limit of 105,800. Assurance provisions are not triggered for the 3-year variability limit.

The variability limits for each state are shown in Tables IV.F–1 through IV.F–3 in section IV. The basis for the variability limits is also described in section IV.F. Additional details may be found in the "Power Sector Variability" TSD in the docket to this rule.

To implement this requirement, EPA would first evaluate whether any state's total EGU emissions in a control period exceeded the state's budget with 1-year variability limit. Next, EPA would evaluate whether any state's total EGU emissions in a control period exceeded the state's budget with the 3-year variability limit (once the program is in effect for 3 years, and each year thereafter). If any state's EGU emissions in a control period exceeded either of these limits, then EPA would apply additional criteria to determine which source owners in the state would be subject to an allowance surrender requirement. The proposed allowance surrender requirement that owners surrender allowances under the assurance provisions would be triggered only for owners of units in a state where the total state EGU emissions for a control period exceed the applicable state budget with the variability limit. Moreover, only an owner whose units" emissions exceed the owner's share of the state budget with the variability limit would be subject to the allowance surrender requirement.

In applying the additional criteria, EPA would evaluate which source owners in the state had emissions exceeding the respective owner's share of the state budget with the variability limit (regardless of whether the source had enough allowances to cover its emissions). An owner's share would equal the sum of the allocations of its EGUs in the state, plus its proportional share of the amount of the variability limit that, when included with the state budget, was exceeded by the state's EGU emissions during the year involved. If the state emissions exceeded both the state budget with the 1-year and with the 3-year variability limit, then the 3-year variability limit would be used in determining the owner's share of the state budget.

On the other hand, if the state's total EGU emissions for a control period in a given year did not exceed the state budget with the state's 1-year variability limit and did not exceed, on a 3-year rolling average basis, the state budget with the state's 3-year variability limit, then the additional criteria concerning the emissions of each owner's sources in the state would not apply. For more details see subsection V.D.4.i, later, and the rule text at the end of this preamble (§§ 97.425, 97.525, 97.625, and 97.725—Compliance with assurance provisions).

As discussed previously, EPA would not allocate emissions allowances to a new unit for the control period during which the unit commences commercial operation. In the case where assurance provisions for a state are triggered in the year that a new unit first operates, the owner's share—if calculated as the sum of the allocations of its EGUs plus its proportional share of the variability limit—would necessarily be zero because the new unit would have no allocation for that year. Instead, EPA would use a specific surrogate emissions number to calculate the maximum amount the unit could emit in that year before being required to surrender allowances under the assurance provisions. The surrogate emissions number would apply only if the state's assurance provisions were triggered and only in the first year of the new unit's operation.

The surrogate emissions number would be calculated by multiplying the unit's allowable emissions rate (in lbs/MWe) by the unit's maximum hourly load (in MWe/hr) and a default capacity factor specific to the unit type. The default capacity factors would be: 84 percent for coal-fired units, 66 percent for gas-fired combined cycle units, and 15 percent for combustion turbines in the NO_X annual and SO_2 trading programs; and 89 percent for coal-fired units, 72 percent for gas-fired combined cycle units, and 22 percent for combustion turbines in the NO_X ozone season trading program. These percentages are based on the 95th percentile capacity factors for these unit types in quarterly data that have been reported to EPA for coal-fired units commencing operation since 2000 and combustion turbines since 2004. EPA believes that this approach would cover a range of operating conditions for new units and thus avoid attributing to each new unit a share of the state budget with variability reflecting the maximum amount of emissions possible for the unit in its first operating year, in the case where the state's assurance provisions were triggered. (See "Capacity Factors Analysis for New Units" TSD in the docket for further information on the proposed default capacity factors for new units).

These assurance provisions are above and beyond the fundamental requirement for each source to hold enough allowances to cover its emissions in the control period. Failure to hold enough allowances to cover emissions is a violation of the CAA, subject to an automatic penalty and discretionary civil penalties, as described later.

EPA believes the likelihood of triggering assurance provisions is low. The State Budgets/Limited Trading programs have a regional cap that limits overall emissions; state-specific budgets that are the basis for allocating emissions allowances in each state; assurance provisions that each state eliminates the excess emissions leading to significant contribution and interference with maintenance that EPA has identified in this proposed action; and additional allowance surrender requirements for not meeting emissions reductions requirements. As discussed in section e, later, the underlying mechanism of cap and trade, even without assurance provisions, has succeeded in reducing emissions below allowance levels. The accumulated data, history, and experience from these programs underscore that emissions reductions requirements and environmental and public health goals of the programs were met. However, unlike earlier cap and trade programs (*e.g.*, the Acid Rain, CAIR, and NO_X Budget Trading Programs), where allocations were made based on the same average emissions rates for classes of units, in this proposed rule EPA specifically designed budgets that were intended to match up with reductions at certain cost levels used to determine the respective state's significant contribution and interference with maintenance. This means more units are likely to have allocations close to their emissions when the state is eliminating its significant contribution and interference with maintenance and there is likely to be less need for trading in order for sources to comply with the requirement to hold allowances covering emissions. Additionally, EPA has now added assurance provisions to ensure that emissions within a state do not exceed the state budget with the variability limitation.

The existence of these assurance provisions will limit incentives to trade and ensure that state emissions will stay below the level of the budget with the variability limit. An example of a circumstance that might result in emissions approaching the variability limit is an extended nuclear unit outage that causes a company to run its fossil units harder to meet demand. Increased emissions under such a scenario would not result from the ability to trade across state boundaries, or because the fossil units were not controlled, but because the units were operated more. In this type of scenario, emissions would also be higher in a rate-based program that did not allow interstate trading.

EPA is setting two criteria to determine if a state has exceeded its budget using the state budget with the 1-year variability limit on an annual basis, and the state budget with the 3-year variability limit on a 3-year rolling average basis. EPA proposes that emissions from an owner's EGUs in excess of the owner's share of the state budget with the variability limit would not be a violation of the regulation or the CAA. But the owner would be required to make an allowance surrender of one allowance for each ton emitted over the owner's proportional share of the amount by which state emissions exceed the state budget with the variability limit.

This allowance surrender requirement is significant, and EPA believes sufficient, to ensure that the state emissions will not exceed the budgets plus the variability limit. The allowance surrender requirement, however, is less severe than the penalties (discussed later) that apply if a source fails to comply with the requirement to hold an allowance for each ton emitted by EGUs at the source. However, failing to hold sufficient allowances to meet the allowance surrender requirement would be a violation of the regulations and the CAA.

EPA requests comment on whether the allowance surrender requirement should be different (either more or less) than one allowance per ton emitted over the owner's proportional share of the state budget with the variability limit. In addition, EPA requests comment on whether the exceedance of total emissions by an owner's sources over the owner's share of the state budget with the variability limit should be a violation of the CAA and thus subject to discretionary penalties. Finally, EPA requests comment on all aspects of the proposed assurance provisions in the proposed FIPs.

(6) Penalties

All covered sources must hold an allowance for each ton of SO_2 or NO_X emitted and are subject to penalties if they fail to comply with this allowance-holding requirement.

Each source must hold in its compliance account in the AMS enough allowances issued for the respective annual trading program (SO_2 group 1, SO_2 group 2, or NO_X annual programs) to cover the annual emissions of the relevant pollutant from all the EGUs at the source. The source owner must provide, for deduction by the Administrator, one allowance as an offset and one allowance as an excess emissions penalty for each ton of excess emissions. These are automatic penalties-they are required, without any further action by EPA (*e.g.*, any additional proceedings), regardless of the reason for the occurrence of the excess emissions. In addition, each ton of excess emissions, as well as each day in the averaging period (*i.e.*, a calendar year), is a violation of the CAA, for which the maximum discretionary penalty is $25,000 (inflation-adjusted to $37,500 for 2009) per violation under CAA Section 113.

For the ozone season control program, the same provisions apply as for an annual program, except that the control period (and averaging period) is the ozone season, not a calendar year. Consequently, the relevant allowances and emissions are for an ozone season.

EPA requests comment on the amount of allowances required for the automatic penalties.

c. 2012 and 2013 Transition Period

For the 2012–2013 transition period, EPA is proposing the State Budgets/Limited Trading remedy without the previously-described assurance provisions (penalty provisions would remain in effect), but taking comment on whether the assurance provisions should be in force during that period.

New state-specific control budgets (developed as described in section IV) and new allowances would be allocated to sources in the Transport Rule region. These state budgets would reflect the operation of all existing and planned emission control devices. Under EPA's proposed approach, for 2012 and 2013, intrastate and interstate trading, without the assurance provisions, would be allowed.

The locations of existing and planned air pollution control retrofits on EGUs are known, and this knowledge provides greater certainty of where reductions will occur and how these reductions should impact air quality in downwind areas. There would not be sufficient time to complete construction of additional control retrofits or entirely new, controlled EGUs before 2014.[87]

Consequently, EPA believes that there is a high level of certainty that emissions reductions projected for

[87] U.S. Environmental Protection Agency (U.S. EPA). 2002. Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies. Washington, DC.

2012–2013 with interstate trading would be achieved within the states where they are projected to occur, making imposition of the assurance provisions during 2012–2013 unnecessary. In addition, EPA believes that the two alternative options discussed later present greater implementation challenges than this proposed interim remedy for 2012–2013. See sections V.D.5 and V.D.6. Except for the absence of the assurance provisions, the remedy for 2012–2013 would be the same as the State Budgets/Limited Trading option, including compliance and penalty provisions described previously.

The 2012–2013 transition period would provide time for sources to migrate to the new rule requirements in 2014, such as preparing for the imposition of the assurance provisions and, for some states, tighter SO_2 budgets. EPA is requesting comment on the proposed approach of locking in emissions reductions for 2012 and 2013 by allocating new state-specific budgets based on significant contribution and interference with maintenance and ensuring that pollution control devices operate, while allowing for interstate trading in 2012 and 2013 without the assurance provisions. Assurance provisions would provide sources less flexibility and therefore likely increase compliance costs, but would be required starting in 2014. EPA requests comment on the pros and cons of including assurance provisions or other limitations on trading during the 2012–2013 period. Section IV.F presents variability limits for the alternative where assurance provisions would apply during 2012 and 2013 (see Tables IV.F–1 through IV.F–4).

d. Electric Reliability

The State Budgets/Limited Trading remedy is not a risk to electric reliability. The option for sources to trade across state borders and to emit up to the specified state budget with variability limit gives ISOs (Independent System Operators) the flexibility to manage regional electricity generation so that reliability is maintained. For example, the operations of the electricity generation sector under the State Budgets/Limited Trading remedy, as compared to the option allowing only intrastate trading, would be less constrained by state borders and have greater flexibility to handle unexpected events such as extreme weather or the loss of generating capacity for extended periods of time.

e. How Emissions Cap and Trade Programs Have Worked Under Title IV, the NO_X SIP Call, and CAIR

Even absent assurance provisions, cap and trade programs have resulted in broad-based emissions reductions distributed across the entire covered area, with the reductions coming where emissions were highest and most cost effective. The national SO_2 emissions cap and trade program that EPA implemented under Title IV of the CAA Amendments (the Acid Rain Program) and the regional SO_2 and NO_X programs established under CAA section 110(a)(2)(D)(i), in the form of the NO_X Budget Trading Program and the three CAIR trading programs, all have several key components in common:

- Phases and reductions.
  - An emissions cap is established and the programs are phased in, with increasing stringency to lower emissions.
- Allowance allocation.
  - Authorizations to emit, *i.e.*, allowances, are allocated to affected sources and are limited by each state's trading budget.
- Allowance trading.
  - Markets enable sources to trade allowances.
- Flexible compliance.
  - Sources have the flexibility to choose the most efficient way to comply including adding emission control technologies, updating control technologies, optimizing existing controls, switching fuels, and buying allowances.
- Annual reconciliation.
  - At the end of every compliance period, each source must surrender sufficient allowances to cover its emissions. Excess allowances may be sold or banked for future use.
- Penalties and enforcement.
  - There are automatic penalties and potentially discretionary civil penalties for program noncompliance.
- Stringent monitoring and reporting.
  - Sources must use approved monitoring methods under EPA's stringent monitoring requirements (40 CFR part 75) to monitor and report emissions.
- Data transparency.
  - The data on key program elements, such as emissions, allocations, and allowance trades, are publicly available on EPA's web site and in annual progress reports.

About 50 government staff operate these cap and trade programs. They have been successful in achieving the emissions reductions goals at reasonable costs with virtually 100 percent program compliance. In the following paragraphs, specific results from the programs are described. These results are documented in program progress reports that are available on EPA's Web site (*http://www.epagov/airmarkets/progress/progress-reports.html*) and in the docket to this rule, as referenced at the end of each program section later.

Title IV Acid Rain Program—Emissions Reductions

Since program implementation in 1995, the ARP has reduced SO_2 and NO_X emissions from the power sector across the nation. In 2008, the ARP SO_2 program covered 3,572 electric generating units (including 1,055 coal-fired units, which account for almost 99 percent of total ARP unit SO_2 emissions). Verified data submitted to EPA from 2008 show that:

- SO_2 emissions from power sector sources were 7.6 million tons, which is 52 percent less than 1990 levels and already below the statutory annual emission cap of 8.95 million tons set for compliance in 2010.
- NO_X emissions from power sector sources were 3.0 million tons, which is 51 percent less than 1995 levels and more than double the Title IV NO_X program emission reduction objective, but also reflects reductions achieved under the NO_X Budget and CAIR NO_X trading programs.

The largest reductions have occurred in the states with the highest power plant emissions. These high emitting areas were upwind of major populations centers and areas of environmental and ecological concern. Emissions reductions have led to improvements in air quality with significant benefits to sensitive ecosystems and human health.

- Between the 1989 to 1991 and 2006 to 2008 observation periods, decreases in wet sulfate deposition averaged more than 30 percent for the eastern U.S.
- Acid Neutralizing Capacity (ANC), the ability of water bodies to neutralize acid deposition, increased significantly from 1990 to 2008 in lake and stream long-term monitoring sites in New England, the Adirondacks, and the Northern Appalachian Plateau.
- Recently updated assessments of U.S. $PM_{2.5}$ and ozone health-related benefits estimate that $PM_{2.5}$ benefits due to ARP implementation in 2010 are valued at $170–$410 billion annually and ground-level ozone benefits from ARP implementation in 2010 are valued at $4.1–$17 billion (estimates are in 2008 dollars). The benefits are primarily from reduced premature mortality.

See EPA's docket for this rule and *http://www.epagov/airmarkets/progress/ARP_4.html.*

NO_X SIP Call NO_X Budget Trading Program—Emissions Reductions. From 2003–2008, the NBP reduced ozone season NO_X emissions throughout the NO_X SIP Call region each year. Results of the program include:

- In 2008, NBP ozone season NO_X emissions totaled 481,420 tons, which is 62 percent below 2000 levels and 9 percent below the 2008 NO_X emissions cap. Emissions were also below the caps in 2006 and 2007.
- The average NO_X emissions rate for the 10 highest electric demand days (as measured by megawatt hours of generation) consistently fell every year of the NBP.
- The largest NO_X emissions reductions and 8-hour ozone concentrations reductions took place along the Ohio River Valley, as was projected by EPA air quality models of the NO_X SIP Call.
- Noticeable improvements in ambient concentrations of ozone have been measured across the region.
- Of the 104 areas in the eastern United States designated to be in nonattainment for the 1997 8-hour ozone NAAQS in 2004, 88 areas (85 percent) had ozone air quality better than the level of the 1997 standard in 2008. 8-hour ozone concentrations were 10 percent lower in 2008 than in 2001. This decline is largely due to reductions in NO_X emissions required by the NO_X SIP Call rule.[88]

Over the past several years a series of studies [89] [90] [91] have evaluated the NO_X SIP Call and the link between decreasing NO_X emissions and decreasing ozone concentrations. These studies demonstrate that the NO_X SIP Call has been effective in improving ozone air quality in the eastern U.S.

EPA stopped administering the NBP at the conclusion of 2008 control period. States still have the emissions reductions requirements under the NO_X SIP Call and can use the CAIR NO_X ozone season trading program to meet these.

See EPA's docket for this rule for more details on the results of the NO_X Budget Trading Program, or see *http://www.epagov/airmarkets/progress/NBP_4.html.*

CAIR—Emissions Reductions. Anticipation of the CAIR regional program in 2008 resulted in an additional 2.8 million tons of SO_2 reductions from 2005 levels in the eastern United States, bringing emissions well under the 2010 Title IV cap. The NO_X annual and ozone season programs began on January 1 and May 1, 2009, respectively. The SO_2 program began on January 1, 2010. The CAIR cap and trade programs remain in effect, consistent with the Court's remand, in order to benefit public health and the environment, until EPA replaces the rule.

Allowance trading. Because of the ease with which allowances can be banked, bought and sold, and transferred in the trading programs, robust allowance trading markets have developed over the past fifteen years, along with considerable banking of allowances.

Allowance prices and trading activity under the trading programs were reduced in 2008 in response to the Court's July 2008 decision in North Carolina v. EPA granting petitions for review of CAIR. However, the allowance markets remained active. For a recent assessment on allowance markets, *see http://www.epagov/airmarkets/resource/docs/marketassessmnt.pdf.*

Transaction Costs. The cap and trade program results described previously are real, measurable, and very significant. These results demonstrate that cap and trade is a policy tool that can achieve cost-effective, broad reductions quickly to improve human health and the environment and help states meet their obligations to attain the NAAQS. While some have suggested that transaction costs associated with cap and trade programs were high or problematic, EPA has found no indication that this is the case. Transaction costs are important because they can diminish the incentive to trade or the amount traded.

In fact, few empirical studies on transaction costs have been done. EPA has searched the literature and compiled a list of anecdotal discussions on transaction costs, including a study of the ARP's SO_2 cap and trade program by Ellerman [92] of MIT, published in 2004. Ellerman suggests that, while no comprehensive study has been conducted on the subject, "* * * the creation of a standard unit of account in allowances and the lack of any review requirement for trading has avoided the very large transactions costs that limited * * * earlier experiments with emissions trading." Other studies (see Schennach, 2000 [93]) suggest transaction costs are about one percent of the allowance price. An industry expert, Gary Hart,[94] suggested that a typical fee charged by a brokerage firm is $0.50 for each SO_2 allowance.

Tietenberg, in his book, *Emissions Trading Principles and Practice,*[95] explains the role of transaction costs and their impact on trading. Note that Tietenberg and many economists use the word, "permits," in the same way EPA uses the word, "allowances."

Tietenberg defines transactions costs as "the costs, other than price, incurred in the process of exchanging goods and services. These include the costs of researching the market, finding buyers or sellers, negotiating and enforcing contracts for permit transfers, completing all the regulatory paperwork, and making and collecting payments." [96] He also describes how to lower transaction costs, as follows: "Transaction costs can be lowered by making permit transactions transparent, by the availability of exchanges and knowledgeable brokers, and by the sharing of information on the availability of cost-effective abatement technologies, while administrative costs can be lowered by continuous emissions monitoring and by software that streamlines monitoring and reporting." [97] He goes on to say, "Price transparency (making prices public) can reduce the uncertainty associated with trading and facilitate negotiations about price and quantity. One good example is [the] public auctions held each spring for the Sulfur Allowance Program [ARP]." [98]

Tietenberg contrasts EPA's earlier credit-based trading programs in the

[88] U.S. EPA, Our Nation's Air Status and Trends through 2008, Office of Air Quality Planning and Standards, EPA–454/R–09–002, Research Triangle Park, NC, pp. 1, 17.

[89] Gégo, E., P.S. Porter, A. Gilliland, and S.T. Rao, 2007: Observation-Based Assessment of the Impact of Nitrogen Oxides Emissions Reductions on Ozone Air Quality over the Eastern United States. J. Appl. Meteor. Climatol., 46, 994–1008.

[90] Godowitch, J.M., Hogfrefe, C., & Rao, S.T. 2008. Diagnostic analyses of a regional air quality model: Changes in modeled processes affecting ozone and chemical-transport indicators from NO_X point source emission reductions. Journal of Geophysical Research, 113, D19303, doi:10.1029/2007JD009537.

[91] Godowitch, J.M., Gilliland, A.B., Draxler, R.R., and Rao, S.T. 2008. Modeling assessment of point source NO_X emission reductions on ozone air quality in the eastern United States. Atmospheric Environment, 42 (1), 87–100.

[92] Ellerman, A. Denny. 2004. "The U.S. SO_2 Cap-and-Trade Programme," Tradeable Permits: Policy Evaluation, Design and Reform, chapter 3, pp. 71–97, OECD.

[93] Schennach, S.M. 2000. The Economics of Pollution Permit Banking in the Context of Title IV of the 1990 Clean Air Act Amendments. Journal of Environmental Economics and Management 40(3): 189–210.

[94] Personal communication with Gary Hart, ICAP-United, June 25, 2007 as quoted in Napolitano, S., J. Schreifels, G. Stevens, M. Witt, M. LaCount, R. Forte, & K. Smith. 2007. "The U.S. Acid Rain Program: Key Insights from the Design, Operation, and Assessment of a Cap-and-Trade Program." Electricity Journal. Aug/Sept. 2007, Vol. 20, Issue 7. doi:10.1016/j.tej.2007.07.001.

[95] Tietenberg, T.H. 2006. Emissions Trading Principles and Practice. Washington, DC. Published by Resources for the Future.

[96] *Ibid.,* p. 41.

[97] *Ibid.,* p. 73.

[98] *Ibid.,* pp. 70–71.

1970s and 1980s (U.S. Emissions Trading Program (ETP)) with cap and trade programs, such as the Acid Rain Program for SO_2. He says that while credit-based programs "typically involved a considerable amount of regulatory oversight at each step of the process (*e.g.*, certification of credits and approval of each trade)," cap and trade programs use instead a system "that compares actual and authorized emissions at the end of the year, which can lower transactions costs" compared to a credit program.

All the features Tietenberg highlights comprise fundamental aspects of EPA's cap and trade program design. Program design remains one of the principle ways to ensure lower transaction costs. Over the last 15 years, EPA's state-of-the-art information management system has evolved in parallel with the advancement of technology in order to offer platforms for reporting and receiving data and for public access. EPA provides dedicated assistance for sources, states, and regions around the country on program operations and monitoring and reporting, specifically. With limited oversight of transactions, EPA focuses on recording data and information accurately, including allowance transfers, as well as "true-up", where actual emissions are reconciled with allowances held in accounts for compliance.

These features of EPA's program management lead to low transaction costs. EPA is attuned to trying to keep requirements as simple and straightforward as possible, and offers substantial and routine training to ensure successful program implementation and regulatory compliance. While some have equated the length of EPA's trading program rules with higher transaction costs, in fact, the detailed regulatory sections, such as for allocations and the stringent monitoring requirements, form the basis of what actually allows the programs to function with limited oversight, virtually 100 percent compliance, public transparency, and nominal transaction costs.

For the ARP, NO_X Budget Trading Program, and CAIR trading programs, EPA records all allowance allocations in accounts in an electronic allowance tracking system (currently called the AMS). In addition, EPA records in the AMS all allowance transfers that are submitted by parties for official recordation. These allowance accounts are searchable and visible to the public. The trading program regulations that directly govern allowance trading, *i.e.*, the regulations governing the establishment of allowance accounts and the submission of allowance transfers, are relatively simple and establish requirements that are easy to meet. *See, e.g.*, 40 CFR 96.151(a) (requiring establishment of source compliance accounts). Allowances may be held in an allowance account (*i.e.*, banked) for use or trading in any future year in which the trading program involved is in effect. *See, e.g.*, 40 CFR 96.155 (allowing banking). Further, allowances may be transferred from one account to another with no restrictions except the requirements that the authorized account representative of the transferor account submit to EPA a simple (generally electronic) allowance transfer form identifying the allowances to be transferred and the account to receive them, and that the allowances must be currently recorded in the transferor account. *See, e.g.*, 40 CFR 96.160 (requiring submission of specified allowance transfer form) and 96.161(a)(2) (requiring that allowance be in transferor account). This transparency of data and availability of information allows the allowance market to function smoothly.

EPA research found no indications that transaction costs have been a problem. From discussions with a leading industry consultant we learned that there is enough competition among the approximately fifteen brokerage houses that any attempt at charging fees in excess of market standards will be bid down through competition.[99] In many instances, clients can negotiate fees even lower than market averages. Financial exchanges, such as the Chicago Climate Exchange and New York Mercantile Exchange, added SO_2 and NO_X allowances to their list of commodities. Prior to the vacatur of CAIR, transaction costs (broker fee as a percent of allowance price) were estimated at less than 0.2 percent for SO_2, less than 1.8 percent for seasonal NO_X, and less than 0.5 percent for annual NO_X.[100] These transaction costs are low and not expected to affect program outcome.

In summary, EPA believes its cap and trade programs functioned efficiently and did not result in high transaction costs for several reasons. First, in developing the regulations for the trading programs, EPA strove to make the programs as transparent as possible in order to ensure that relevant data were available to the market, to minimize regulatory oversight of trading activity, and to let the market work unhampered. Strong markets exist that have seen upwards of 273 million SO_2 allowances transferred to date. Educational and professional associations that hold regular conferences for members, regulated entities, government agents, and the public have existed to increase transparency of information and exchange ideas on cap and trade programs for more than a decade.

Further, EPA is not aware of any source participating in the trading programs over the past 15 years that expressed concern about the costs of making allowance transfers. For example, EPA has received no comment in the rulemaking proceedings for the trading programs raising concern about the level of transactions costs for allowance transfers under these programs, and no party challenged the allowance transfer provisions on appeal of any of the trading program rules.

In addition, all available information indicates that actual transactions costs are very low. For a list of some articles written by scholars and economists over the past 15 years on transaction costs, see the docket for this rule.

f. How the Remedy in the Proposed FIPs Is Consistent With the Court's Opinions

The proposed remedy discussed in this section effectuates the statutory goal of prohibiting sources within the state from contributing to nonattainment or interfering with maintenance in any other state. *See North Carolina,* 531 F.3d at 908. The proposed FIPs eliminate all or the emissions that EPA has identified as significantly contributing to downwind nonattainment or interference with maintenance in today's proposed action by requiring sources to participate in emissions trading programs that allow intrastate trading and limited interstate trading, and that also include provisions to ensure that no state's emissions exceed that state's budget with variability limit. These assurance provisions, combined with the requirement that all sources hold emissions allowances sufficient to cover their emissions, effectuate the requirement that emissions reductions occur "within the State."

A state's "significant contribution" is the portion of emissions that must be eliminated.[101] State budgets represent EPA's estimate of the remaining emissions after elimination of significant contribution, but in actuality

[99] Memo from ICF International to EPA Clean air Markets Division, September 17, 2008. *Transaction Costs in Allowance Trading Markets.*

[100] *Ibid.*

[101] Note that in cases where EPA has not fully identified the quantity of emissions that represent significant contribution or interference with maintenance, state budgets define the emissions that remain after the part that has been identified is eliminated.

the amount of remaining emissions may vary. As explained in greater detail previously, both the budgets and the assurance provisions recognize the inherent variability in state EGU emissions. EPA recognizes that shifts in generation due to, among other things, changing weather patterns, demand growth, or disruptions in electricity supply from other units can affect the amount of generation needed in a specific state and thus baseline EGU emissions from that state. Because states' baseline emissions are variable, their remaining emissions after all significant contribution is eliminated are also variable. In other words, EGU emissions in a state, whose sources have installed all controls and taken all measures necessary to eliminate its significant contribution, could in fact exceed the state budget without variability. For this reason, the assurance provisions limit a state's emissions to the state's budget with variability limit.

In addition, the requirement that all sources hold emissions allowances (and the fact that the total number of emissions allowances allocated will be equal to the sum of all state budgets without variability) ensures that the use of variability limits both takes into account the inherent variability of baseline EGU emissions in individual states (*i.e.*, the variability of total state EGU emissions before the elimination of significant contribution) and recognizes that this variability is not as great in a larger region.

The variability of emissions across a larger region is not as large as the variability of emissions in a single state for several reasons. Increased EGU emissions in one state in one control period often are offset by reduced EGU emissions in another state within the control region in the same control period. In a larger region that includes multiple states, factors that affect electricity generation, and thus EGU emissions levels, are more likely to vary significantly within the region so that resulting emissions changes in different parts of the region are more likely to offset each other. For example, a broad region can encompass states with differing weather patterns, with the result that increased electricity demand and emissions due to weather in one state may be offset by decreased demand and emissions due to weather in another state. By further example, a broad region can encompass states with differing types of industrial and commercial electricity end-users, with the result that changes in electricity demand and emissions among the states due to the effect of economic changes on industrial and commercial companies may be offsetting. Similarly, because states in a broad region may vary in their degree of dependence on fossil-fuel-based electric generation, the impact of an outage of non-fossil-fuel-based generation (*e.g.*, a nuclear plant) in one state may have a very different impact in that state than on other states in the region. Thus, EPA does not believe it is necessary to allow total regional allowance allocations for the states covered by a given trading program to exceed the sum of all state budgets without variability for these states.

For these reasons, the fact that the proposed use of state budgets with the variability limit may allow limited shifting of emissions between states is not inconsistent with the Court's holding that emissions reductions must occur "within the state." *North Carolina,* 531 F.3d at 907. Under the proposed FIPs, no state may emit more than its budget with variability limit and total emissions cannot exceed the sum of all state budgets without variability. This approach takes into account the inherent variability of the baseline emissions without excusing any state from eliminating its significant contribution. It is thus consistent with the statutory mandate of section 110(a)(2)(D)(i)(I) as interpreted by the Court.

g. Why EPA Is Proposing the State Budgets/Limited Trading Option

The FIPs that EPA is proposing use the State Budgets/Limited Trading remedy to eliminate all of the significant contribution and interference with maintenance that EPA has identified. This remedy—which would use state budgets (*see* section IV) and allow full trading within each state and limited trading outside of each state—would be a cost-effective method for eliminating all or part of each state's emissions that constitute a significant contribution and interfere with maintenance, would be consistent with the Court's decision in *North Carolina* v. *EPA,* and would address the issues raised by the Court.

In the first phase (2012 and 2013), the proposed remedy would provide a new interstate trading program that would ensure existing and planned pollution controls operate. Units would be required to run their existing, or already planned, pollution control devices when the units are operating. The State Budgets/Limited Trading remedy would use the new state budgets described in section IV and allocate allowances to individual sources using a methodology directly related to the methodology used to identify emissions that significantly contribute to nonattainment or interfere with maintenance in downwind areas. EPA believes that because the location of existing and already planned pollution controls for 2012 and 2013 is known, the use of these budgets, even without the added assurance provisions, would assure that the necessary emissions reductions would occur in each state under the trading programs during those years. The impact of the resulting emissions reductions on atmospheric concentrations of particulate matter and other pollution, and subsequent benefits for the environment and human health, would be significant and are described in sections III.B and IX. The proposed remedy would offer the most expeditious approach practicable for compliance in 2012–2013, given the short time available for sources, states, and EPA to implement a transition from CAIR. While there is some uncertainty about how quickly units potentially capable of switching fuels would actually be able to implement such fuel switching, the banking provisions of the State Budgets/Limited Trading approach would provide incentives to reduce emissions as quickly and early as possible. The trading provisions would provide flexibility for sources to purchase allowances in the meantime, without the risks of unexpected high costs, non-compliance, or the inability to operate if unable to switch fuels. The remedy would be relatively easy for sources and states to understand and follow as they transition from prior trading programs to a new regime, beginning in 2014, that would include limits on interstate trading.

The second phase would begin in 2014 with tighter state-specific SO_2 caps for states in the more stringent group 1 tier to address significant contribution and interference with maintenance. In addition, assurance provisions limiting interstate trading would become effective in each state. This approach in the proposed remedy, which is modeled in several ways after the approaches of the ARP and NBP programs, is likely to lead to virtually 100 percent compliance. The approach ensures that, as we see economic growth, future air quality is not compromised and states can depend on emissions reductions in meeting local air quality goals.

The limited interstate trading permitted in this proposed remedy would address some of the problematic issues identified in the alternative options discussed later, such as, under the intrastate trading option, concerns about the administrative burden and needed resources associated with administering 82 new trading programs (with 82 new sets of allowances),

conducting 82 annual auctions, concentrated allowance market power within individual states, and regional electricity reliability. In particular, the interstate trading component with assurance provisions would mean that allowances issued for one state for a trading program could be used in any of the states included in the respective trading program. This feature of the proposed remedy would create a regionwide allowance market, rather than single-state allowance markets where individual owners of sources would be much more likely to have market power (see discussion later in section V.D.5). Further, the interstate trading component with assurance provisions would provide source owners with much more flexibility to ensure electric reliability in the event of future variability in electricity demand (*e.g.*, due to weather or economic changes) or in the availability of specific individual electricity generation facilities.

In addition, the proposed State Budgets/Limited Trading remedy provides reductions at a lower cost than the direct control option described later and is flexible enough to accommodate unit-specific circumstances. In contrast, the direct control option described later would involve a complex process of determining unit-by-unit emissions limits that might need to take account of unit-specific circumstances. Moreover, this option would be roughly $600 million (2006$) more expensive than the proposed remedy in 2012. See section V.E for more details on projected costs and emissions.

In summary, EPA believes that interstate trading, although limited by the assurance provisions, would allow source owners to choose among several compliance options to achieve required emissions reductions in the most cost-effective manner, such as installing controls, changing fuels, reducing utilization, buying allowances, or any combination of these actions. Interstate trading with assurance provisions would also allow the electricity sector to continue to operate as an integrated, interstate system able to provide electric reliability. Compared to the alternative options, EPA believes the State Budgets/Limited Trading remedy would provide the greatest flexibility to companies complying with the rules and is the approach most likely to achieve the goals and principles outlined in section III.C.

The proposed remedy provides intrastate and interstate trading components that simplify implementation for EPA (and, where applicable, states) and sources and results in cost-effective achievement of required emissions reductions. Resource needs for EPA and sources to implement the proposed remedy are expected to be comparable to the resources necessary to implement CAIR.

EPA believes the State Budgets/Limited Trading proposed remedy provides more assurance that the emissions levels necessary to address NAAQS nonattainment are not exceeded than most previous regulatory programs such as rate-based direct control programs and even nonattainment plans, none of which places an absolute cap on emissions. EPA has pointed out, in contrast, that the results from cap and trade programs such as the Acid Rain and NO_X Budget Trading programs demonstrate how substantial emissions reductions have been delivered throughout the respective covered region with high levels of compliance, at low costs, and with significant health and ecological benefits. The proposed State Budgets/Limited Trading remedy provides added assurance that emissions reductions now will occur on a state-by-state basis, not just overall at a regional level. These assurance provisions would prohibit states from exceeding their state-level budgets with variability limits and impose stringent and costly allowance surrender requirements that are known upfront to deter exceedances. EPA is confident that the proposed program is both reasonable to implement and stronger than the alternative options.

Additionally, this remedy approach and the method EPA proposes for determining significant contribution together provide a workable regulatory structure for not only dealing with the transport problem for the existing NAAQS, but also would be usable in the years ahead when EPA considers further revisions of the NAAQS, notably for ozone and fine particles. EPA requests comment on the State Budgets/Limited Trading proposed remedy. EPA is also requesting comment on the two options described later in sections V.D.5 and V.D.6.

h. Other Limited Interstate Trading Options Evaluated

EPA considered a range of ways to create an interstate-trading-with-limitations option consistent with the direction provided by the Court. One option considered was to put in place simultaneously intrastate trading with direct control requirements and interstate trading with direct control requirements. The challenges associated with developing direct control requirements are discussed in section V.D.6 later.

EPA also considered interstate trading with backstop provisions, which were rejected as not workable. EPA considered a backstop provision that prohibited the units in a state from future participation in the interstate trading program if the state's emissions in a control period in any year exceeded the state's budget with variability. In that event, the units would be limited to intrastate trading only in the control period of the next year. This is not EPA's proposed option because data on annual emissions are not final until several months into the next year, making it hard for the units in a state to know early enough whether they would be in the interstate trading program or an intrastate trading program for that next year. This would make compliance planning and implementation of compliance plans extremely difficult and adversely affect allowance markets.

In summary, EPA rejected these alternatives as more complicated and perhaps problematic to implement. Instead, EPA is proposing the State Budgets/Limited Trading remedy, which is similar in many ways to the approaches implemented in the past that have succeeded in reducing emissions. However, in order to address the Court's concerns about trading, the proposed remedy includes assurance provisions to ensure that the remedy removes each upwind state's significant contribution and interference with maintenance. The "Other Remedy Options Evaluated" TSD in the docket contains greater detail on the deliberations undertaken to evaluate other options for this rulemaking.

i. Structure and Key Elements of Proposed Transport Rule Trading Program Rules for State Budgets/Limited Trading

This preamble section describes the structure and key elements of the proposed Transport Rule trading program rules for the State Budgets/Limited Trading remedy in the proposed FIPs. Proposed regulatory text that would be added to the Code of Federal Regulations if this option is finalized appears at the end of this notice. EPA requests comment on the structure and key elements of the program as well as on the proposed regulatory text.

In order to make the proposed FIP trading program rules as simple and consistent as possible, EPA designed them so that the proposed rules for each of the trading programs (*i.e.*, the Transport Rule NO_X Annual trading program, Transport Rule NO_X Ozone Season trading program, Transport Rule

SO_2 Group 1 trading program, and Transport Rule SO_2 Group 2 trading program) would be parallel in structure and contain the same basic elements. For example, the proposed rules for the Transport Rule NO_X Annual, NO_X Ozone Season, SO_2 Group 1, and SO_2 Group 2 trading programs would be located, respectively, in subparts AAAAA, BBBBB, CCCCC, and DDDDD of Part 97. Moreover, the order of the specific provisions for each trading program would be same, and the provisions would have parallel numbering. The key elements of the proposed Transport Rule trading program rules are discussed later.

(1) General Provisions

(i) §§ 97.402 and 97.403, 97.502 and 97.503, 97.602 and 97.603, and 97.702 and 97.703—Definitions and Abbreviations

The definitions and measurements, abbreviations, and acronyms would be the same in all four proposed Transport Rule trading programs, except where necessary to reflect the different pollutants (NO_X and SO_2), control periods (for NO_X, annual and ozone season), and geographic coverage (for SO_2, Group 1 and Group 2) involved. Moreover, many of the definitions would be essentially the same as those used in prior EPA-administered trading programs, in some cases with modifications to reflect the specific, proposed Transport Rule trading program involved. For example, the definitions of "unit" and "source" would be the same as in prior trading programs. As a further example, the definitions of "allowance transfer deadline," "owner," and "operator" would be the same as in prior trading programs, except for references to Transport Rule NO_X Annual allowances, Transport Rule NO_X Ozone Season allowances, Transport Rule SO_2 Group 1 allowances, or Transport Rule SO_2 Group 2 allowances or Transport Rule NO_X Annual units and sources, Transport Rule NO_X Ozone Season units and sources, Transport Rule SO_2 Group 1 units and sources, or Transport Rule SO_2 Group 2 units and sources, as appropriate. As a further example, the term "Allowance Management System" would be used instead of the term "Allowance Tracking System" but would have essentially the same definition, while referencing the type of allowances appropriate for the proposed Transport Rule trading program involved. As a further example, "continuous emission monitoring system" is essentially the same as in prior trading programs, except for references to the proposed Transport Rule trading program rules.

Some definitions would be similar to those used in prior EPA-administered trading programs but with some substantive differences. For example, the definitions of "cogeneration unit" and "fossil-fuel-fired," used in the applicability provisions and discussed in this section of the preamble, would be similar to those in prior trading programs but with changes to minimize the need for data concerning individual units or combustion devices for periods before 1990.

A few new definitions would be included to reflect unique provisions of the proposed Transport Rule trading programs. For example, the terms, "owner's assurance level" and "owner's share", would be used in the Transport Rule assurance provisions and defined in the proposed Transport Rule trading program rules. The assurance provisions are discussed previously in section V.D.4.b.

(ii) §§ 97.404 and 97.405, 97.504 and 97.505, 97.604 and 97.605, and 97.704 and 97.705—Applicability and Retired Units

The applicability provisions would be the same for each of the proposed Transport Rule trading programs, except that the provisions would reflect (through the definition of "state") differences in the specific states whose EGUs are covered by the respective Transport Rule trading programs (as discussed in section IV.D of this preamble). In general, the proposed Transport Rule trading programs would cover fossil fuel-fired boilers and combustion turbines serving an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale, with the exception of certain cogeneration units and solid waste incineration units. The applicability provisions are discussed previously in section V.D.4.b.

The provisions exempting permanently retired units from most of the requirements of the Transport Rule trading programs would be the same for each of the trading programs. The purpose of the retired units" exemption would be to avoid requiring units that are permanently retired to continue to operate and maintain emission monitoring systems, to report quarterly emissions, and to hold allowances, as of the allowance transfer deadline, sufficient to cover their emissions determined in accordance with the monitoring and reporting requirements. Consequently, the retired unit provisions would exempt these units from the rule sections imposing the relevant monitoring, recordkeeping, and reporting requirements and allowance-holding requirements. However, an owner would include each of these permanently retired units that it owns in determining whether and, if so, how many allowances the owner would be required to surrender in compliance with the assurance provisions. As discussed earlier in this section, while these units would have zero emissions once they are permanently retired, the units could continue to receive allowance allocations for several years thereafter. Consequently, an owner would include these units in determining whether the owner's share of total emissions of covered units in a state exceeded its share (generally based on the allowances allocated to its units) of the state budget with the variability limit and thus whether the owner would have to surrender allowances under the assurance provisions.

The exemption for a retired unit would begin on the day the unit is permanently retired. The unit's designated representative (*i.e.*, the person authorized by the owners and operators to make submissions and handle other matters) would be required to submit notification to the Administrator within 30 days of the unit's permanent retirement.

The retired unit exemption provisions would not directly address any permit-related matters concerning these units. This would be consistent with the general approach under the Transport Rule trading program rules of leaving permitting matters largely to be addressed by the existing, applicable state and federal title V permit programs. Permitting is discussed in section VIII of this preamble.

(iii) §§ 97.406, 97.506, 97.606, and 97.706—Standard Requirements

The basic requirements applicable to owners and operators of units and sources covered by the proposed Transport Rule trading programs and presented as standard requirements would include: Designated representative requirements; emissions monitoring, reporting, and recordkeeping requirements; emissions requirements comprising emissions limitations and assurance provisions; permit requirements; additional recordkeeping and reporting requirements; liability provisions; and provisions describing the effect of the Transport Rule trading program requirements on other Act provisions. The paragraphs, in the standard requirements section, that would address designated representative requirements and emissions monitoring, reporting, and recordkeeping

requirements would reference the details of these requirements in other sections of the proposed Transport Rule trading program rules.

The paragraphs addressing emissions requirements would describe these requirements in detail and reference other sections that would set forth the procedures for determining compliance with the emissions limitations and assurance provisions. These paragraphs would also explain that: Transport Rule NO_X Annual allowances, Transport Rule NO_X Ozone Season allowances, Transport Rule SO_2 Group 1 allowances, or Transport Rule SO_2 Group 2 allowances would each authorize emission of one ton of emissions under the applicable Transport Rule trading program; such authorizations could be terminated or limited by the Administrator to the extent necessary or appropriate to implement any provision of the CAA; and such allowances would not constitute a property right. The proposed Transport Rule SO_2 trading programs use new SO_2 allowances and not CAA Title IV allowances, thus the provisions allowing the Administrator to terminate or limit the Transport Rule trading program allowances under this rule would not be contrary to the Court's *North Carolina* decision, which addressed the Administrator's authority to terminate or limit Title IV SO_2 allowances through the CAIR.

The remaining paragraphs in the standard requirements section concern permitting, recordkeeping and reporting, liability provisions, and the effect on other CAA provisions. As discussed in section VIII of this preamble, the paragraphs concerning permitting requirements would be limited to stating that no title V permit revisions would be necessary to account for allowance allocation, holding, deduction, or transfer and that the minor permit modification procedures could be used to add or change general descriptions in the title V permits of the monitoring and reporting approach used by the units covered by each title V permit. The paragraphs on recordkeeping and reporting would generally require owners and operators to keep on site for 5 years copies (which could be electronic) of certificates of representation, emissions monitoring information (including quarterly emissions data), and submissions and records demonstrating compliance with the proposed Transport Rule trading programs. The paragraphs on liability would state that each covered source and covered unit would be required to meet the Transport Rule trading program requirements, any provision applicable to a source or designated representative would be applicable to the source and unit owners and operators, and any provision applicable to a unit or designated representative would be applicable to the unit owners and operators. The paragraph on the effect on other CAA provisions would state that the Transport Rule trading programs do not exempt or exclude owners and operators from any other requirements under the CAA, an approved SIP, or a federally enforceable permit.

(iv) §§ 96.407, 97.507, 97.607, and 97.707—Computation of Time

These sections would clarify how to determine the deadlines referenced in the proposed Transport Rule trading program rules. For example, deadlines falling on a weekend or holiday are extended to the next business day. These are the same computation-of-time provisions used in prior EPA-administered trading programs.

(v) §§ 97.408, 97.508, 97.608, 97.708 and Part 78—Administrative Appeal Procedures

Final decisions of the Administrator under the proposed Transport Rule trading program rules would be appealable to EPA's Environmental Appeals Board under the regulations that are set forth in part 78 (40 CFR part 78) and are proposed to be revised to accommodate such appeals. Specifically, the list in § 78.1 of the types of final decisions that could be appealed under Part 78 would be expanded to include specific types of decisions under the proposed Transport Rule trading program rules.

Further, under the approach in the existing part 78, an "interested person" (in addition to the official representative of owners and operators or an allowance account involved in a matter) may petition for an administrative appeal of a final decision of the Administrator. In order to expand the "interested person" definition (which is currently in part 72 of the ARP regulations) and make the definition more readily accessible to readers of part 78, the definition would be removed from § 72.2, added in § 78.2, and expanded in a way that would cover the proposed trading program rules. Provisions concerning public availability of information, and provisions concerning computation of time (revised to be consistent with the requirements for computation of time used by the Environmental Appeals Board in other types of administrative proceedings), would also be moved to § 78.2. In particular, the revised "interested person" definition would include, with regard to a decision appealable under Part 78, any person who—in connection with the Administrator's process of making that decision—submitted comments, testified at a public hearing, submitted objections, or submitted their name to be included by the Administrator in an interested persons list.

In addition, § 78.3 would be revised to allow for petitions for administrative appeal of decisions of the Administrator under the proposed Transport Rule trading programs. Further, § 78.4 would be expanded to state that filings on behalf of owners and operators of a covered source or unit under the proposed Transport Rule trading programs would have to be signed by the designated representative of the source or unit. Filings on behalf of persons with an interest in allowances in an account in the proposed programs would have to be signed by the authorized account representative of the account.

(2) Allowance Allocations

Sections 97.410 through 97.412, 97.510 through 97.512, 97.610 through 97.612, and 97.710 through 97.712 would set forth: Certain information related to allowance allocation and for implementation of the assurance provisions; the timing for allocation of allowances to existing and new units; and the procedures for new unit allocations. In particular, these sections would include tables providing, for each state covered by the particular proposed Transport Rule trading program and for each year, the state trading budget (without the variability limit), new unit set-aside, and one-year and three-year variability limits. With regard to existing units, these sections would also state that existing units would be allocated the allowances set forth in appendix A of the relevant Transport Rule trading program rules. These allocations would be permanent (taking into account the reductions in allocations, for the Transport Rule SO_2 Group 1 trading program, from Phase I to Phase II) with one exception. A unit that does not operate (*i.e.*, has no heat input) for three consecutive years starting in 2012 would continue to receive its Appendix A allocation for those years plus only three more years. Starting in the seventh year, the Administrator would stop recording the allocations for the unit and would instead add to the new unit set-aside the allowances that would otherwise have been recorded for the non-operating unit. Because the proposed unit-by-unit allocations are set forth in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD cited previously,

the proposed Transport Rule trading program rules do not repeat these allocations in Appendix A to each rule. Instead, each Appendix A is reserved, and EPA proposes to include the unit-by-unit allocations, for each Transport Rule trading program, in Appendix A to the respective final Transport Rule trading program rules.

With regard to new units (as well as units whose allocations are subject to the requirement that the Administrator not record them or that the Administrator deduct the amount of the allocation and units that lost their allocations after not operating and that subsequently began operating again), the owner and operator of such units could request, by a specified deadline each year, an allocation from the new unit set-aside for that year and each year thereafter. The allocation would equal that unit's emissions—as determined in accordance with part 75 (40 CFR part 75)—for the control period (annual or ozone season, depending on the Transport Rule trading program involved) in the preceding year. The Administrator would determine whether the total number of properly requested allowance allocations for all units in a state for a control period would exceed the amount in the new unit set-aside for the state for the control period. If not, the Administrator would allocate consistent with all proper requests. If the total number would exceed the new unit set-aside, the Administrator would allocate to each properly requesting unit its proportionate share of the new unit set-aside. The Administrator would provide notice of these determinations (which would reflect these calculations rather than any exercise of discretion on the part of the Administrator) through issuance of a notice of data availability to which parties could submit objections and a second notice addressing any objections. Any unallocated allowances in the new unit set-aside would be allocated to existing units in proportion to their current allocations.

If a unit that was not really a covered unit or a unit that was not subject to the allowance-holding requirement were allocated allowances, the proposed provisions set forth a process under which the allocation would not be recorded or the amount of the recorded allocation would be deducted, with one exception. The exception would be if the process of determining compliance with the emission limitation for the source that includes the unit were already completed, in which case no action would be taken to account for the erroneous allocation for the control period involved.

(3) Designated Representatives and Alternate Designated Representatives

Sections 97.413 through 97.418, 97.513 through 97.518, 97.613 through 97.618, and 97.713 through 97.718 would establish the procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of a source and the units at the source and for changing the designated representative and alternate designated representative. These sections would also describe the designated representative's and alternate designated representative's responsibilities and the process through which he or she could delegate to an agent the authority to make electronic submissions to the Administrator. These provisions would be patterned after the provisions concerning designated representatives and alternates in prior EPA-administered trading programs.

The designated representative would be the individual authorized to represent the owners and operators of each covered source and covered unit at the source in matters pertaining to all Transport Rule trading programs to which the source and units were subject. This approach would ensure that one individual was required to be knowledgeable about the requirements of, and responsible for compliance with, all Transport Rule trading programs. One alternate designated representative could be selected to act on behalf of, and legally bind, the designated representative and thus the owners and operators. Because the actions of the designated representative and alternate would legally bind the owners and operators, the designated representative and alternate would have to submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators and was authorized to act on their behalf.

The designated representative and alternate would be authorized upon receipt by the Administrator of the certificate of representation. This document, in a format prescribed by the Administrator, would include: Specified identifying information for the covered source and covered units at the source and for the designated representative and alternate; the name of every owner and operator of the source and units; and certification language and signatures of the designated representative and alternate. All submissions (*e.g.*, monitoring plans, monitoring system certifications, and allowance transfers) for a covered source or covered unit would have to be submitted, signed, and certified by the designated representative or alternate. Further, upon receipt of a complete certificate of representation, the Administrator would establish a compliance account in the Allowance Management System for the source involved.

In order to change the designated representative or alternate, a new certificate of representation would have to be received by the Administrator. A new certificate of representation would also have to be submitted to reflect changes in the owners and operators of the source and units involved. However, new owners and operators would be bound by the existing certificate of representation even in the absence of such a submission.

In addition to the flexibility provided by allowing an alternate to act for the designated representative (*e.g.*, in circumstances where the designated representative might be unavailable), additional flexibility would be provided by allowing the designated representative or alternate to delegate authority to make electronic submissions on his or her behalf. The designated representative or alternate could designate agents to submit electronically certain specified documents. The previously-described requirements for designated representatives and alternates would provide regulated entities with flexibility in assigning responsibilities under the Transport Rule trading programs, while ensuring accountability by owners and operators and simplifying the administration of the proposed Transport Rule trading programs.

(4) Allowance Management System

The Transport Rule trading program rules listed later would establish the procedures and requirements for using and operating the Allowance Management System (which is the electronic data system through which the Administrator would handle allowance allocation, holding, transfer, and deduction), and for determining compliance with the emissions limitations and assurance provisions, in an efficient and transparent manner. The Allowance Management System would also provide the allowance markets with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred. Consistent with the approach in prior EPA-administered trading program, allowance price

information would not be included in the Allowance Management System. EPA's experience is that private parties (*e.g.*, brokers) are in a better position to obtain and disseminate timely, accurate allowance price information than is EPA. For example, because not all allowance transfers are immediately reported to the Administrator for recordation, the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices.

(vi) §§ 97.420, 97.520, 97.620, and 97.720—Compliance and General Accounts

The Allowance Management System would contain two types of accounts: compliance accounts, one of which the Administrator would establish for each covered source upon receipt of the certificate of representation for the source; and general accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any allowances used by the covered source for compliance with the emissions limitations and assurance provisions would have to be held. The designated representative and alternate for the source would also be the authorized account representative and alternate for the compliance account. Using source-level, rather than unit-level accounts, would provide owners and operators more flexibility in managing their allowances for compliance, without jeopardizing the environmental goals of the Transport Rule trading programs, because the source-level approach would avoid situations where a unit would hold insufficient allowances and would be in violation of allowance-holding requirements even though units at the same source had more than enough allowances to meet these requirements for the entire source.

General accounts could be used by any person or group for holding or trading allowances. However, allowances could not be used for compliance with emissions limitations or assurance provisions so long as the allowances were held in, and not properly and timely transferred out of, a general account. To open a general account, a person or group would have to submit an application for a general account, which would be similar in many ways to a certificate of representation. The application would include, in a format prescribed by the Administrator: The name and identifying information of the individual who would be the authorized account representative and of any individual who would be the alternate authorized account representative; an identifying name for the account; the names of all persons with an ownership interest with the respect to allowances held in the account; and certification language and signatures of the authorized account representative and alternate. The authorized account representative and alternate would be authorized upon receipt of the application by the Administrator. The provisions for changing the authorized account representative and alternate, for changing the application to take account of changes in the persons having an ownership interest with respect to allowances, and for delegating authority to make electronic submissions would be analogous to those applicable to comparable matters for designated representatives and alternates.

(vii) §§ 97.421 Through 97.423, 97.521 Through 97.523, 97.621 Through 97.623, and 97.721 Through 97.723—Recordation of Allowance Allocations and Transfers

By September 1, 2011, the Administrator would record allowance allocations for existing units, based on Appendix A to each proposed Transport Rule trading program rule, for 2012 through 2014. By June 1, 2012 and June 1 of each year thereafter, the Administrator would record such allowance allocations for each proposed Transport Rule trading program for the third year after the year of the recordation deadline, *e.g.*, for 2015 in 2012. Recording these allowance allocations about 3 years in advance of the first year for which they could be used for compliance would facilitate compliance planning by owners and operators and promote robust allowance markets, including futures markets for allowances. By September 1 (for the Transport Rule NO_X and SO_2 annual trading programs and June 1, for the Transport Rule NO_X Ozone Season program) of each year starting with 2012, the Administrator would record allowance allocations for that year from the new unit set-aside. Because this would occur before the allowance transfer deadline for each proposed Transport Rule trading program involved, this would still allow for trading and thereby promote robust allowance markets.

The process for transferring allowances from one account to another would be quite simple. A transfer would be submitted providing, in a format prescribed by the Administrator, the account numbers of the accounts involved, the serial numbers of the allowances involved, and the name and signature of the transferring authorized account representative or alternate. If the transfer form containing all the required information were submitted to the Administrator and, when the Administrator attempted to record the transfer, the transferor account included the allowances identified in the form, the Administrator would record the transfer by moving the allowances from the transferor account to the transferee account within 5 business days of the receipt of the transfer form.

(viii) §§ 97.424, 97.524, 97.624, and 97.724—Compliance With Emissions Limitations

Once a control period has ended (*i.e.*, December 31 for the Transport Rule NO_X and SO_2 annual trading programs and September 30 for the NO_X ozone season trading program), covered sources would have a window of opportunity (*i.e.*, until the allowance transfer deadline of midnight on March 1 or December 1 following the control period for the annual and ozone season trading programs respectively) to evaluate their reported emissions and obtain any allowances that they might need to cover their emissions during the control period. Each allowance issued in each proposed Transport Rule trading program would authorize emission of one ton of the pollutant, and so would be usable for compliance, for a control period in the year for which the allowance was allocated or a later year. Consequently, each source would need—as of the allowance transfer deadline—to have in its compliance account, or have a properly submitted transfer that would move into its compliance account, enough allowances usable for compliance to authorize the source's total emissions for the control period. The authorized account representative could identify specific allowances to be deducted, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis.

If a source were to fail to hold sufficient allowances for compliance, then the owners and operators would have to provide, for deduction by the Administrator, 2 allowances allocated for the control period in the next year for every allowance that the owners and operators failed to hold as required to cover emissions. In addition, the owners and operators would be subject to discretionary civil penalties for each violation, with each ton of unauthorized emissions and each day of the control

period involved constituting a violation of the Clean Air Act.

EPA believes that it is important to include a requirement for an automatic deduction of allowances. The deduction of one allowance per allowance that the owners and operators failed to hold would offset this failure. The deduction of another allowance per allowance that the owners and operators failed to hold would provide an automatic penalty that could not be avoided, regardless of any explanation provided by the owners and operators for their failure, and would therefore provide a strong incentive for compliance with the allowance-holding requirement by ensuring that non-compliance would be a significantly more expensive option than compliance.

(ix) §§ 97.425, 97.525, 97.625, and 97.725—Compliance With Assurance Provisions

EPA proposes to include assurance provisions in the Transport Rule trading programs in order to ensure that each state would eliminate that part of its significant contribution and interference with maintenance that EPA has identified in today's proposed action (*see* section V.D.4.b previously). As previously discussed, a requirement that owners surrender allowances under the assurance provisions would be triggered only for owners of units in a state where the total state EGU emissions for a control period would exceed the applicable state budget with the variability limit. Moreover, only an owner whose units' emissions would exceed the owner's share of the state budget with the variability limit would be subject to the allowance surrender.

The process of determining, for a given control period, which states would have total EGU emissions sufficient to trigger the allowance surrender requirement, which owners would be subject to the allowance surrender, and whether those owners were in compliance would be implemented in a series of steps. (The dates summarized later apply to the proposed annual programs; the dates for the proposed ozone season program would be earlier.)

First, the Administrator would perform the calculations necessary to determine whether any states had total state EGU emissions for a control period greater than the state budget with the variability limit, applying both the 1-year and the 3-year variability limits discussed earlier. By June 1 (starting in 2015), the Administrator would promulgate a notice of availability of the results of these calculations and provide an opportunity for submission of objections. By August 1, the Administrator would promulgate a second notice of availability of any necessary adjustments to the calculations and the reasons for accepting or rejecting any properly submitted objections.

Second, by August 15, the designated representative of every Transport Rule source in a state identified in the August 1 notice as having control period emissions in excess of the budget with the variability limit would make a submission to the Administrator that would identify: Each person having (as of the last day of the control period) a legal, equitable, leasehold, or contractual reservation or entitlement in the Transport Rule units at the source; and the percentage of each such person's reservation or entitlement.

Third, by September 15, the Administrator would calculate, for each state identified in the August 1 notice and for each owner of covered units in the state, the owner's share of emissions, the owner's share of the state budget with the variability limit, and the amount (if any) that the owner would be required to hold for surrender under the assurance provisions (*i.e.*, the owner's proportionate share of the excess of state emissions over the state budget with the variability limit). The Administrator would promulgate a notice of availability of the results of these calculations, provide an opportunity for submission of objections, and promulgate by November 15 a second notice of availability of any necessary adjustments to the calculations and the reasons for accepting or rejecting any properly submitted objections.

By December 1, each owner identified in the November 15 notice as being required to hold allowances for surrender under the assurance provisions would designate a compliance account of one of its covered units in the state, and the authorized account representative of the compliance account would submit to the Administrator a statement designating the compliance account, as the account in which the required allowances would be held.

As of midnight of December 15, the owner would have to have in its designated compliance account, or have a properly submitted transfer that would move into that compliance account, the amount of allowances (usable for compliance) that the Administrator determined (in the calculations referenced in the November 15 notice) were required to be held by the owner for surrender. The authorized account representative could identify specific allowances to be deducted but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct allowances on a first-in, first-out basis.

The potential effect of subsequent data revisions that would otherwise change the data used in and the results of the Administrator's calculations referenced in the August 1 or November 15 notices discussed previously would be limited. If data used in a notice applying the assurance provisions to a given year were revised as a result of a decision in, or settlement of, litigation (such as an administrative appeal resulting in such decision or settlement or an administrative appeal whose results were in turn appealed in a judicial proceeding resulting in such decision or settlement) initiated within 30 days of the promulgation of the notice involved, then the Administrator would use the revised data for the calculations in the respective notice. Any other data revisions would not be used to revise the calculations. The revised data could be used, if relevant, in the Administrator's calculations in future notices promulgated for a later year. If the revised calculations increased the amount of allowances that an owner was required to hold for surrender, the Administrator would set a new, reasonable deadline for the owner to hold the additional allowances in the owner's designated compliance account. The Administrator believes that this limitation on the effect of data revisions on the calculation of the amount of allowances owners would have to surrender under the assurance provisions is necessary. Because an owner's surrender obligation would be calculated using large amounts of data involving all the covered units in a state (including potentially many units owned by other owners), each owner would face the potential that changes in data outside of the owner's responsibility and control could change—after the December 15 allowance-holding deadline—in a way that would increase his surrender obligation after that deadline and put him in violation of the regulations and the Act. EPA believes that this potential risk would be significant enough that it could make many owners reluctant to consider any compliance options involving even the limited interstate trading allowed under the proposed remedy. The proposal would limit this risk by having the Administrator only take account of data revisions resulting from decisions in, or settlement of, litigation initiated soon after promulgation of the notice involved.

Owners' potential allowance surrender obligations as of the December 15 allowance-holding deadline under the assurance provisions would still be significant even with this limitation on the potential for the surrender obligations to increase after December 15 due to data revisions.

As discussed previously, it would not be a violation of the CAA for total state EGU emissions to exceed the state budget with the variability limit or for an owner to become subject to allowance surrender under the assurance provisions. However, the failure of an owner to hold in the designated compliance account a sufficient amount of allowances to satisfy this allowance surrender would violate the CAA and be subject to discretionary penalties, with each required allowance that was not held and each day of the control period involved constituting a violation. EPA believes that the allowance surrender requirement alone—and certainly when coupled with the potential for large discretionary penalties—would ensure that owners would take actions to avoid having total state EGU emissions exceed the level that would trigger the allowance surrender.

(x) §§ 97.426 Through 97.428, 97.526 Through 97.528, 97.626 Through 97.628, and 97.726 Through 97.728—Miscellaneous Provisions

These sections would allow banking of the allowances issued in the Transport Rule trading programs, *i.e.*, the retention of unused Transport Rule allowances allocated for a given control period for use or trading in a later control period. Banking would allow sources to make emissions reductions beyond required levels and bank the unused allowances for use or trading later. This would encourage development of emissions reductions techniques and technologies and implementation of early reductions, stimulate the allowance markets, and provide flexibility to owners and operators. While this could also potentially cause emissions from sources in some states in some control periods to be greater than the allowances allocated for those control periods, the assurance provisions would limit such emissions in a way that would ensure that the part of each state's significant contribution and interference with maintenance that EPA has identified in today's proposed action would be eliminated.

These sections also would provide that the Administrator could, at his or her discretion and on his or her own motion, correct any type of error that he or she finds in an account in the Allowance Management System. In addition, the Administrator could review any submission under the Transport Rule trading programs, make adjustments to the information in the submission, and deduct or transfer allowances based on such adjusted information.

(5) Emissions Monitoring, Recordkeeping, and Reporting

Sections 97.430 through 97.435, 97.530 through 97.535, 97.630 through 97.635, and 97.730 through 97.735 would establish emissions monitoring, recordkeeping, and reporting requirements for Transport Rule units that would result in clear, consistent, rigorous, and transparent monitoring and reporting of all emissions. Such monitoring and reporting would be the basis for holding sources accountable for their emissions and would be essential to the success of the Transport Rule trading programs. This is because consistent and accurate measurement of emissions would be necessary to ensure that each allowance would actually represent one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton of reported emissions from another source. This would establish the integrity of each allowance and instill confidence in the underlying market mechanisms that would be central to providing sources with flexibility in achieving compliance. Moreover, given the variation in the type, operation, and fuel mix of sources covered by the proposed Transport Rule trading programs, EPA believes that emissions would need to be monitored continuously in order to ensure the precision, reliability, accuracy, and timeliness of emissions data supporting the trading programs.

In §§ 97.430 through 97.435, 97.530 through 97.535, 97.630 through 97.635, and 97.730 through 97.735, EPA proposes the monitoring, recordkeeping, and reporting requirements for the Transport Rule NO_X annual, NO_X ozone season, SO_2 Group 1, and SO_2 Group 2 trading programs, respectively. These provisions reference the relevant sections of Part 75 (40 CFR part 75), where the specific procedures and requirements for monitoring and reporting NO_X and SO_2 mass emissions are found. The proposed provisions are virtually the same as the monitoring, recordkeeping, and reporting requirements under previous EPA-administered trading programs, *e.g.*, the ARP and NO_X Budget and CAIR trading programs.

Part 75 was originally developed for the ARP and addressed SO_2 mass emissions and NO_X emissions rate. The ARP, as established by Congress in CAA Title IV, requires the use of continuous emission monitoring systems (CEMS) or an alternative monitoring system that is demonstrated to provide information with the same precision, reliability, accuracy, and timeliness as a CEMS. Subsequently, Part 75 was expanded, for purposes of the NO_X Budget Trading Program under the NO_X SIP Call, to address monitoring and reporting of NO_X mass emissions. Under Part 75, a unit has several options for monitoring and reporting, namely the use of: A CEMS; an excepted monitoring methodology (NO_X mass monitoring for certain peaking units and SO_2 mass monitoring for certain oil- and gas-fired units); low mass emissions monitoring for certain, non-coal-fired, low emitting units; or an alternative monitoring system approved by the Administrator through a petition process. In addition, under Part 75, the Administrator can approve petitions for alternatives to Part 75 requirements.

The proposed monitoring and reporting provisions for the Transport Rule trading programs would allow use of these same options and petition procedures and would reference the applicable provisions in Part 75. Existing Transport Rule units would be required to install and certify monitoring systems by the beginning of the relevant Transport Rule trading program. New Transport Rule units have separate deadlines based upon the date of commencement of commercial operation. Recognizing that many of the Transport Rule units are already monitoring NO_X and/or SO_2 under Part 75 through existing trading programs, continued use of previously certified monitoring systems would be allowed when appropriate rather than automatically requiring recertification.

The quality assurance (QA) requirements for the ARP that were mandated by Congress under CAA Title IV are codified in Appendices A and B of Part 75. Part 75 specifies that each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits (RATAs) and daily calibrations. A standard set of data validation rules apply to all of the monitoring methodologies. These stringent requirements result in an accurate accounting of the mass emissions from each unit, and EPA provides prompt feedback if the monitoring system is not operating properly. In addition, when the monitoring system is not operating

properly, standard substitute data procedures are applied and result in a conservative estimate of emissions for the period involved. This ensures a level playing field among the regulated units, with consistent accounting for every ton of emissions, and also provides an incentive to properly maintain, and meet the QA requirements for, each monitoring system. The monitoring and reporting provisions in the proposed Transport Rule trading program regulations would contain the same QA requirements and substitute data procedures as in Part 75 and would reference the applicable provisions in Part 75.

Part 75 requires electronic submission, to the Administrator and in a format prescribed by the Administrator, of a quarterly emissions report containing all of the emissions data specified in the recordkeeping provisions of Part 75. EPA has found that centralized, electronic reporting using a consistent format is necessary to ensure consistent review and public posting of the emissions data for covered units, which contribute to the integrity, efficiency, and transparency of trading programs. Further, the inclusion of all emissions data in a single quarterly report for each unit means that, if the same data are needed for multiple trading programs, the unit only needs to report it once in the form of one comprehensive report. The reporting provisions in the proposed Transport Rule trading program regulations would contain the same requirements for submission to the Administrator of electronic, comprehensive quarterly reports as in Part 75. As discussed above, the reporting provisions would also include a process for resubmission of quarterly reports where appropriate.

5. State Budgets/Intrastate Trading Remedy Option

As noted earlier in this preamble, in addition to the remedy option included in the proposed FIPs, EPA is taking comment on two alternative options for eliminating all or part of the emissions in upwind states that significantly contribute to nonattainment or interfere with maintenance in downwind states. The first of these alternative options is the State Budgets/Intrastate Trading option described below. EPA is considering the relative merits of this option and requests comment on whether it should be included in the final FIPs. EPA also identifies below a number of disadvantages that raise concerns for EPA and are explained later in this section. EPA requests comment on these issues and their impacts on and significance for any final rule.

a. Description of Option

The State Budgets/Intrastate Trading option would set state-specific caps for SO_2, NO_X annual, and NO_X ozone season emissions from EGUs and create separate allowance trading programs within each state in the respective regions starting in 2012. The state-specific caps would ensure that all required reductions occur within the state and thus would address the Court's concerns about abating each individual upwind state's unlawful emissions under CAA section 110(a)(2)(D)(i)(I). Similar to other trading programs, the owners and operators of each source would be required to surrender to EPA one allowance for every ton of emissions after the end of every control period. However, a source could only use, for compliance with this requirement, an allowance issued for the state where the source was located. For purposes of obtaining allowances usable in compliance, sources within each state could trade allowances amongst themselves, but not with sources located in other states. Total emissions in each state could not exceed that state's budget and there would be no shifting of emissions to other states thus ensuring that each state's contribution to nonattainment and interference with maintenance with regard to downwind states would be adequately addressed. Banking of allowances for use in a later period would be permitted under this remedy option.

Under this option, EPA would allocate allowances to the covered sources within each state, and sources in the state could use for compliance only allowances issued for the same state. Even a company that operates EGUs in multiple states would not be permitted to use for compliance for one of its sources allowances issued to another of its sources in a different state. In essence, this approach, if implemented, would result in 28 separate trading programs for NO_X annual, 26 trading programs for NO_X ozone season, and 28 trading programs for SO_2 for a total of 82 new trading programs to be administered by EPA. These 82 trading programs would require 82 separate sets of allowances. Companies that own EGUs in more than one state would also be responsible for managing their allowances for each program in each state separately.

Unlike the remedy option in the proposed FIPs or the other alternative remedy option, this option does not include assurance provisions based on the variability limits described in section IV. This option includes a "hard" cap for each state equal to its budget, which provides assurance that reductions will occur in each state and which EPA believes makes additional assurance provisions unnecessary. The State Budgets/Intrastate Trading option does allow banking and the use of banked allowances to provide sources with some degree of operational flexibility in complying with the program. Because this option includes provisions for banking emissions allowances (as does the proposed State Budgets/Limited Trading remedy), limited year-to-year (temporal) emissions variability is allowed. EPA requests comment on this approach to providing for emissions variability. EPA also requests comment on whether assurance provisions based on variability limits should be included in this option.

b. How the Option Would Be Implemented

(1) Applicability

Applicability would be the same for the proposed remedy and for the two alternative options, including this one. Refer to section V.D.4 above for detailed discussion on applicability.

(2) Allocation of Emissions Allowances

While the general approach for calculating allowance allocations would be the same as described above for State Budgets/Limited Trading, EPA would not distribute all of the allowances into the source accounts each period. The distribution of allowances would be modified because of the concentrated nature of numerous state power markets, which would be reflected in the state allowance markets if all allowances were distributed in each state based on factors reflecting generation in that state. The electric power sector tends to be highly concentrated, and, within a state, the majority of generation is often owned by a relatively small number of companies. This assessment of state electricity markets is supported by analysis using the Herfindahl-Hirschman Index, a way to measure the size of firms in relation to the industry and an indicator of the amount of competition among them (see Electric Generation Ownership, Market Concentration and Auction Size Technical Support Document). To address this potential issue concerning the allowance markets in many states, under this option some allowances would be withheld from certain sources in each state that control a large share of fossil-fueled power generation and

would be made available for companies with a small share of generation in the state.

The reason for including this provision is that the dominant power generation companies in each state would likely receive a large share of the allocated allowances and as a result might be able to exert control over allowance prices in the state's allowance market. This market power and potential for allowance price manipulation could pose a threat to the transparency and liquidity of allowance markets and put small owners of fossil-fuel fired generation at a disadvantage regarding their compliance costs unless the owners were given sufficient access to allowances other than through direct purchase from the state's dominant companies. Some of these owners of a small share of generation might already face higher control costs, higher transaction costs, and less flexibility regarding compliance options.

Moreover, the use of allowance market power to manipulate prices could have wider impacts on electricity markets as a whole, electricity prices, and electricity reliability both within and across state borders. Therefore, the State Budgets/Intrastate Trading approach needs to address the potential for excessive market power and ensure that allowances would be available to all covered sources at reasonable market prices.

In order to address the potential market power issue, under this option, not all allowances would be allocated using the allocation method described above in section V.D.4. Rather, a small portion of allowances would be withheld from companies with a large share of a state's total fossil-fuel fired electricity generation. These allowances would be made available for purchase by companies with a small share of generation through an annual auction.

EPA is soliciting comments on whether a potential market power problem could arise or reasons why market manipulation would not be a concern under this alternative remedy. EPA is also soliciting comments on whether the approach of using an annual auction to make allowances available to small generators would satisfactorily address this potential issue. This approach is detailed in subsection (3) below.

The approach described for new unit set-asides and allocations to non-operating units above for State Budgets/Limited Trading in section V.D.4 would remain the same for this option.

(3) Auction of Emissions Allowances

The use of an annual allowance auction would ensure that companies with a small market share in a state would have access to additional allowances, if needed, other than through direct purchase from a large owner of generation and would reduce the opportunity for market price manipulation by dominant companies. This means that EPA would hold a total of 82 auctions every year to separately auction SO_2 and NO_X ozone season and NO_X annual allowances in each of the 82 intrastate trading programs. The auction format would be single-round, uniform-price, sealed bid with an initial reserve price of 70 to 80 percent of the modeled allowance price. Reserve prices would be updated at regular intervals to reflect changes in average market prices over time. Any unsold allowances would be returned to the sources from which they were withheld on a proportional basis. Revenues from the auctions would be deposited in the U.S. Treasury, in accordance with 31 U.S.C. 3302.

EPA would use auctions to address market power concerns rather than other options it considered. The Agency considered using a different allowance allocation method that would take into account an owner's share of total generation and distribute proportionally more allowances to owners of a small share of the total generation in each state. This would also ensure that small owners had sufficient allowances without relying on the open markets. However, EPA opted to use an allocation methodology based directly on the approach used to quantify each state's significant contribution to ensure that a direct link exists between allocations and significant contribution to nonattainment or interference with maintenance. EPA also considered direct sales of allowances withheld from dominant sources but believes that auctions would be better suited for determining the appropriate prices for allowances than EPA would be at setting fixed allowance prices for all trading programs in all states. For these reasons, EPA believes the use of auctions would be the best method to address the issue of potential allowance market manipulation.

EPA prefers to use the single-round, uniform-price, sealed bid format because it is simple for all participants to understand, relatively simple to implement and administer, and deters collusion among bidders. In addition, the utility sector already is familiar with this type of format, and EPA has several years of experience running single-round, sealed-bid auctions for Title IV SO_2 allowances. Other formats considered such as multi-round auctions are believed to be more complicated for participants to understand and more complex to administer and do not discourage collusion.

Entities that meet the following criteria would be eligible to participate in the allowance auction: (1) They are required to hold allowances in the state for compliance; and (2) they own no more than 10 percent of the total fossil-fuel fired generation within the state based on EPA's modeled generation for 2014. EPA considered a range from 5 to 20 percent share of ownership for all states and believes that 10 percent ownership is appropriate for determining what constitutes a small market share for this rule. EPA believes that by limiting the auction to entities that own no more than 10 percent of the fossil-fuel fired generation in a state, it would ensure that each auction has enough participants to make auctions viable and competitive and also ensure that the allowances are available only to those companies that may be at a disadvantage in the open markets. Companies with more than a 10 percent share of generation tend to operate several units, have more flexibility, receive a significant share of allowances, and face lower control and transaction costs. EPA is requesting comment on the share of electric generation used as a threshold for determining participation in auctions and also the percentage of allowances available through auctions.

To implement this option, EPA would withhold 2 to 5 percent of the allowances that would be allocated to companies with more than 10 percent of the generation in order to supply allowances for auction each period. This amount is small enough not to have a significant impact on those EGUs from which the allowances are withheld and large enough to provide a sufficient number of allowances for auction. In more highly concentrated states where few companies control much of the generation, a relatively greater number of allowances would be available through the auction to the smaller, potentially disadvantaged companies. Conversely, in states where the electricity sector is less concentrated, there is less threat of market manipulation and greater likelihood of liquid markets. Thus, in these states relatively fewer allowances would be withheld for auction.

Another variation on this alternative option would be to divide companies in each state into three groups, instead of

just two. The first group would be the companies that own no more than 10 percent of the total fossil-fuel generation within the state and would be able to participate in EPA's allowance auctions. The second group would be companies that own a medium amount of fossil-fuel fired generation (for example, between 10 to 20 percent of the total). These companies would not be allowed to participate in auctions but also would not have to contribute any allowances to the auctions. Finally, the third group would be those remaining companies that own a large share of fossil-fuel generation (for example, more than 20 percent of the total). A small percentage of the allowances allocated to these companies would be withheld to supply the auctions. EPA is asking for comments on this variation on the alternative option and other ways to address potential market power problems and on this alternative option.

(4) Allowance Management System

The allowance management system for the State Budgets/Intrastate Trading option would be consistent with the allowance management system for the State Budgets/Limited Trading programs described above, and with the data system structure EPA has developed for allowance management under its existing cap and trade programs such as the CAIR and the Acid Rain Program.

(5) Monitoring and Reporting

Monitoring and reporting provisions would require complete, quality-assured monitoring, and timely reporting of emissions to assure accountability and provide public access to data, and would be the same for EPA's proposed remedy and the State Budgets/Intrastate Trading option. Refer to section V.D.4 above for detailed discussion on monitoring and reporting requirements.

(6) Penalties

Under the State Budgets/Intrastate Trading option for an annual control program (*i.e.*, any of the 28 SO_2 or 28 NO_X annual programs), the requirement that each source hold in its compliance account one allowance for each ton of emissions, and the penalties for failure to meet this requirement, would be the same as described previously in the Penalties section for the State Budgets/Limited Trading remedy option. However, because sources in a given state can only use allowances issued for that state, the penalties associated with failure to hold one allowance for each ton of emissions are adequate to ensure that emissions from the state do not exceed the state budget (except for some temporal variability due to banking). For this reason, EPA does not believe that any other penalties or assurance provisions (such as the assurance provisions used in the State Budgets/Limited Trading remedy) are necessary to ensure that each state eliminates the portion of significant contribution and interference with maintenance that EPA has identified in today's action. EPA requests comment on this conclusion.

c. How the State Budgets/Intrastate Trading Remedy is Consistent With the Court's Opinions

The state budgets/intrastate trading remedy, by establishing state-specific caps on annual or ozone-season EGU emissions, directly implements the section 110(a)(2)(D)(i)(I) requirement that emissions from sources that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any such national primary or secondary ambient air quality standard be prohibited. Of the three remedy options considered, this option provides the most certainty regarding total annual or ozone-season emissions from each state. For this reason, it most directly addresses the statutory mandate that the emissions reductions occur "within the State."

To implement this remedy option, EPA would use the state budgets without variability limits, developed in accordance with the procedures described in sections IV.D and IV.E. These budgets represent EPA's projection of each affected state's EGU emissions in an average year (before accounting for the inherent variability in power system operations) after the elimination of all emissions that EPA has identified as significantly contributing to nonattainment or interference with maintenance.

The number of allowances in each state budget would be distributed or made available (through an auction or otherwise) to sources in that state. Only allowances distributed or made available to sources in a particular state could be used by sources in that state to satisfy the requirement to hold one allowance for every ton of emissions. Thus, annual (or ozone season) emissions in the state would be capped at the level of the state budget. The limited variability due to banking of emissions could allow limited temporal shifting of emissions, but would not alter the requirement that reductions occur within the state. This remedy is thus sufficient to ensure that all significant contribution and interference with maintenance identified by EPA in today's action is eliminated.

d. Electric Reliability Issues

EPA requests comments about whether the State Budgets/Intrastate Trading alternative option could have adverse consequences for electric reliability. The grid regions, and the movement of electricity within each grid region, do not correspond with, and are not limited by, state borders. For example, an increase in electricity demand (*e.g.*, due to a hot summer), or a decrease in electricity supply (*e.g.*, due to a major generation capacity outage), in a given state will not necessarily be met, or offset, through increased electricity generation in that same state. Instead, the increased demand or reduced supply may well result in increased generation outside that state. The sources of the increased generation will be determined by availability and economics and will not necessarily be confined to generation sources in that state. In fact, the ability to obtain additional or replacement supply from sources in another part of the state or from another state enhances electric reliability.

Although companies in one state obtain electricity from sources in multiple states, the State Budgets/Intrastate Trading option would establish emissions budgets on a state basis and would not allow sources in one state to use allowances issued to sources in other states. A source could use, in covering emissions for the current year, both allowances allocated for the current year and banked allowances issued by its state for a past year. However, this option would provide sources less trading flexibility than the proposed State Budgets/Limited Trading remedy. The other remedy options allow for emissions variability, which should largely address electric reliability concerns.

EPA requests comment on whether the State Budgets/Intrastate Trading alternative would provide sufficient flexibility for reliable operation of the integrated grid and, if not, whether there would be ways of preventing or reducing adverse effects such as including additional emissions variability provisions in this option or other approaches. EPA requests comment on approaches to provide additional emissions variability, or other approaches to increasing flexibility, in this option that would be consistent with eliminating all or part of the significant contribution and interference with maintenance that EPA has identified.

e. How Smaller Market Trading Programs Have Worked

These examples of small trading programs below are relevant to further understanding of the State Budgets/ Intrastate Trading remedy option. While small trading programs can succeed, they can also have serious consequences for allowance and electricity markets. Budgets and caps, allowance availability, and prices all can have a profound impact on generation and energy prices for consumers in addition to any air quality benefits. In addition, states range in size and number of potential program participants making each state's circumstances unique and more challenging for EPA to monitor.

(1) Texas Mass Emissions Cap and Trade (MECT)

EPA has approved a NO_X cap and trade program as part of an ozone attainment SIP for the Houston Galveston Brazoria (HGB) nonattainment area in Texas. The program knows as the Mass Emissions Cap and Trade (MECT) program establishes a mandatory NO_X annual emissions cap for stationary facilities in the HGB area located at sites with a collective uncontrolled design capacity to emit 10 tons per year or more of NO_X. The MECT program source population is relatively small but very diverse and covers, among others, EGUs, refineries, chemical plants, and industrial and commercial boilers. The diverse source population allows the MECT program to be a viable means of reducing NO_X emissions without impacting electric reliability. Overall, the MECT program has not encountered major problems caused by its small size and has resulted in environmental benefits for the HGB area.

The MECT program establishes a hard cap for NO_X emissions at a level modeled as necessary for the area to reach ozone attainment. The MECT program started January 1, 2002 and the NO_X cap stepped down each subsequent year until reaching the final cap level of 80 percent of the baseline NO_X emissions in January 2007. In the MECT program one allowance is equivalent to one ton of NO_X emissions. Allowances are allocated to existing facilities on January 1 of each control period, which spans the calendar year. Facilities that do not receive allowances as "existing facilities" (those in operation at the time of program inception) must purchase excess allowances from other covered sources to operate and demonstrate compliance. All covered sources are required to hold sufficient allowances at the end of each control period to equal NO_X emissions during the same time period. Allowances can be used in the control period of allocation, traded to another covered source in the MECT for use in the same time period, or banked for use in the following control period.

Allowances can be traded in one of four ways: Vintage trades, current year trades, individual future year trades, or stream trades. Vintage trades involve the immediate transfer of vintage allowances. Current year trades involve the immediate transfer of current allowances. Individual future year and stream trades involve the transfer of future allowances, with stream trades involving a transfer of allowances in perpetuity. Analysis conducted by the Texas Commission on Environmental Quality of the MECT program trading history shows that approximately 20 percent of the allowances allocated each year are traded and that nearly 50 percent of all program participants have participated in allowance trading. Allowance prices are set by market demand. Prices of individual year allowances have steadily increased as the program has progressed, showing that the value of the allowances increases as the cap tightens. Stream trade prices have fluctuated throughout the program, but have steadily increased as the final cap level has been reached.

(2) Regional Clean Air Incentives Market (RECLAIM)

In comparison to MECT, RECLAIM is a small trading program that has faced a number of challenges due to initial program design decisions. In 1994, RECLAIM established a cap and trade program for NO_X and SO_2 emissions as part of an effort to improve air quality in the Los Angeles area. Every year the caps decline to meet the objective of getting the area into compliance with ozone and particulate matter NAAQS. One noteworthy feature of the RECLAIM trading programs is the two overlapping cycles. Roughly equal numbers of facilities were assigned to each of the two compliance cycles. Facilities in compliance cycle 1 complete their twelve month cycle at the end of the calendar year (December 31), while facilities in compliance cycle 2 complete their twelve-month cycle at the end of the fiscal year (June 30). Around 300 facilities have participated annually in the RECLAIM NO_X trading program. Every facility then complied using valid credits of either cycle, but banking of allowances for use in a later period was not allowed.

RECLAIM Trading Credits (RTC) prices for NO_X rose from about $3,000 per ton early in 2000 to nearly $20,000 per ton in June and up to about $70,000 per ton in August of that year. Prices of RTCs during the California energy crisis during 2000 and 2001 averaged in the $50,000 per ton range.[102] While the California crisis was the result of several malfunctions in the market, the RTC price spike was exacerbated by a number of factors starting with the fact that few emissions reductions had been made in earlier years. Prior to the California crisis, RTCs had been over-allocated, RTC prices had remained low, and utilities had taken little action to install costly controls. When emissions increased and exceeded the level of allocated RTCs, prices shot up to very high levels. In addition, there has been speculation that high RTC prices at the time were partly caused by the high demand for credits resulting directly from the manipulation of the power market by generators.[103]

The operation of the RECLAIM market also contributed to the high prices in the overall power markets. During this period, generators would pay excessively high prices for RTCs in order to raise the price of southern California generation needed to meet demand in the California Independent System Operator (CAISO). Subsequently, generation with high RTC costs in the RECLAIM area would be used to set the electricity price for all of California. The result was that generators could then collect excessive profits on their generation located outside the RECLAIM area. In addition, RECLAIM's overlapping compliance cycles and assignment of facilities to one of two compliance cycles appears to have contributed to some confusion among the participants in the markets.[104] Since that time, significant changes have been adopted to improve the program.

According to the audit report for the 2007 compliance period, total aggregate NO_X emissions were below total allocations by 21 percent and total aggregate SOX emissions were below total allocations by 13 percent. Since January 2008, NO_X RTCs prices have been declining and have not exceeded $15,000 per ton.

[102] Joskow, Paul and Edward Kahn, 2002. A Quantitative Analysis of Pricing Behavior In California's Wholesale Electricity Market During Summer 2000: The Final Word.

[103] Kolstad, Jonathan T. and Frank A. Wolak, 2003. Using Environmental Emissions Permit Prices to Raise Electricity Prices: Evidence from the California Electricity Market. Published by University of California Energy Institute.

[104] Holland, Stephen P. and Michael Moore, 2008. When to Pollute, When to Abate? Intertemporal Permit Use in the Los Angeles NO_X Market. Published by University of California Energy Institute.

f. Why This Is Not the Preferred Option

As explained above, EPA is requesting comment on a State Budgets/Intrastate Trading remedy as an alternative option because this option would provide certainty regarding emissions from each state. However, this option would be more resource intensive, more complex, less flexible, and potentially more susceptible to market manipulation than the other options on which EPA is taking comment.

Although this remedy may be perceived as relatively easy to understand and follow, it would actually be more burdensome to administer due to the number of trading programs that would be required to operate simultaneously and annual auctions that would be held every year to address the issues of market power within states. It would also result in a greater burden for participants operating EGUs in several states. Finally, EPA is asking for comment on whether this option raises electric reliability issues since sources would have less flexibility and fewer options for compliance. EPA is requesting comments on this approach, specifically on alterations that could address the drawbacks identified above or on any other weaknesses of this option not identified by EPA. EPA also welcomes comments regarding the validity of the concerns with this approach identified above.

6. Direct Control Remedy Option

The second alternative option on which EPA is requesting comment is the direct control option described in this section. EPA is considering the relative merits of this option and requests comment on whether a direct control remedy option should be included in the final FIPs.

There are a variety of ways to construct a direct control option. The approach that EPA is presenting as an alternative to the remedy in the proposed FIPs would assign emissions rate limits to individual sources. Emissions limits would take the form of input-based emissions rate limits (lb/mmBtu).

EPA requests comments on the direct control remedy summarized later and the approach for determining emissions rate limits, which is described in greater detail in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rulemaking. Specifically, EPA requests comment on the general use of a direct control remedy as well as the specific rate-based direct control approach described later. EPA also requests comment on the potential weakness of this remedy option identified in the discussion later. In addition, EPA requests comment on alternate methodologies which could be used to implement a direct control remedy.

See section V.E. later for projected costs and emissions associated with this option.

a. Description of Option

Unlike the proposed remedy option (State Budgets/Limited Trading) and the other alternative remedy option (Intrastate Trading) discussed previously, which both use flexible cap-and-trade approaches, a direct control remedy would directly regulate individual sources. Under this direct control remedy alternative, each owner of EGUs would be required to meet specified average emissions rate limits covering all of its EGUs in each covered state. In a state covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS, the direct control remedy option would require each company within the state to meet specified EGU annual emissions rate limits for SO_2 and NO_X. In a state covered for the 8-hour ozone NAAQS, this remedy would require each company within the state to meet specified EGU ozone season emissions rate limits for NO_X. EPA would set emissions rates on a unit-by-unit basis in all covered states (*see* approach to determine emissions rate limits, later).

While emissions rates in all states would be set on a unit-by-unit level, a company would be allowed to average the emissions at its units within each state to meet the specified within-the-state rate limits. Company-level average rates would be calculated as company-level total emissions divided by company-level total heat input in each state. Analogously, allowable company-level average rates would be calculated using unit-specific rate limits and the heat inputs used to determine those allowable rates (as discussed in 6.b.1). A company that exceeded the applicable average rate limits would be subject to penalties (described later).

In addition, to address the potential variability in annual emissions associated with emissions rate limits (*i.e.*, not all years are average), starting in 2012, each state's total annual (or ozone season, as applicable) EGU emissions would also be capped. Emissions from EGUs in each state would be limited to the state's emissions budget with the variability limit. Each state's EGU emissions would be capped in the following two ways. First, the state's EGU emissions would not be permitted to exceed the state budget with the state's 1-year variability limit in any year (or ozone season, as applicable). Second, on average, the state's EGU emissions would not be permitted to exceed the budget with the state's 3-year variability limit, evaluated as a 3-year rolling annual (or ozone season) average (or, in SO_2 group 1 states during 2012 and 2013, a 2-year rolling average). *See* section IV.E for lists of each state's emissions budgets. Section IV.F describes EPA's proposed approach to variability. Tables IV.F–1 through IV.F–3 present 1-year and 3-year variability limits. Table IV.F–4 presents 1-year and 2-year variability limits for SO_2 group 1 states during 2012 and 2013.

If total EGU emissions in a state exceed either of these limits (*i.e.*, budget with 1-year variability limit in any year, or budget with 2-or 3-year variability limit on average), then each company with units in the state whose emissions in the state exceeded the company's share of the state budget with variability limit would be subject to a penalty. These assurance provisions are designed to assure that emissions in each covered state do not exceed the state's budget with variability limit. They are described later. EPA also believes the penalty provisions described later are sufficient to ensure that these caps would not be exceeded.

To implement this remedy option, EPA would determine unit-level emissions rate limits for SO_2, NO_X annual, and NO_X ozone season at levels such that, if the units operated at the levels assumed in determining the state budgets, total emissions of each pollutant from these units would sum to each state's emissions budget for the pollutant without the variability limit. The method for determining these rate limits is described later.

An alternative direct control approach would be to create individual unit-level annual emissions caps (*e.g.*, tons/year) in order to cap emissions in each state. However, this approach would greatly limit operational flexibility and increase risk to electric reliability. For example, a unit-level annual emissions cap approach could prevent a peaking unit from running at a time when the unit is necessary for electric reliability. EPA does not believe that a unit-level annual emissions cap approach is workable.

b. How the Option Would Be Implemented

(1) Approach To Determine Emissions Rate Limits

To implement this remedy option, EPA would determine unit-level emissions rate limits for SO_2, NO_X annual, and NO_X ozone season, for covered EGUs in the covered states.

Emissions rate limits would be set at levels such that, if the units operated at the levels assumed in determining the state budgets, total emissions from these units would sum to the state budgets. In a state covered for purposes of the $PM_{2.5}$ NAAQS, EPA would determine SO_2 and NO_X annual emissions rate limits for each covered EGU. In a state covered for purposes of the 8-hour ozone NAAQS, EPA would determine NO_X ozone season emissions rate limits for each covered EGU.

Emissions rate limits for Phase I (2012 and 2013). State budgets were derived from the lower of available 2007–2009 quarterly emissions or IPM base case projections for 2012, at the state level. Analogous to state budget calculation, EPA would base the Phase I annual emissions rate limit on either the unit's reported annual emissions rate or the IPM projected rate. Rates based on reported data would be calculated using the most recent first, second, third, and fourth quarters of emissions data reported to EPA, between the first quarter of 2007 and the third quarter of 2009, where four such quarters of reported data are available. EPA would determine ozone season rates based on a unit's most recent ozone season emissions reported to EPA during the period of 2007–2009, if available, and projections or source-specific judgments otherwise.

For units where EPA is aware that SO_2 or NO_X controls will be installed by 2012 and such controls were not reflected in the unit's reported emissions rate as determined previously (*i.e.*, the control was not in operation during the period of time on which emissions limits were based), EPA would determine the Phase I emissions rate limit as the historic rate adjusted (reduced) to reflect operation of the planned control equipment at an emissions rate consistent with operation of that equipment. Emissions rate limits would be determined based on the assumption that units operate all existing SO_2 and NO_X control equipment, and the assumption that the type of fuel used does not change from that used in determining the unadjusted rate limit.

For those EGUs which did not report a first, second, third, and fourth quarter of SO_2, NO_X, and/or a complete ozone season of NO_X emissions data to EPA during the 2007–2009 period, or for those units located in states where budgets are based on IPM projections, EPA would determine emissions rate limits based on modeling projections. Based on the analysis conducted for this proposed rule, EPA would use modeling projections to determine SO_2 rates for approximately 1,600 units, annual NO_X rates for 1,800 units, and ozone season NO_X rates for 1,900 units. EPA seeks comment on the ability of all such units to achieve these limits based on IPM projections. *See* table entitled "Phase I and Phase II unit-level emission rate limits" located in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rulemaking.

For those units that did not report data for a given pollutant and time frame combination and also were not included in IPM modeling, EPA would need to determine permissible rates based on unit characteristics (*e.g.*, types and sizes of units, fuel type). The approach would also need to take into account the variety of controls and measures that can be used to limit emissions, including available fuels. While EPA does not believe that such units exist, EPA is taking comment on the existence of units that did not report first, second, third, and fourth quarter data to EPA between the first quarter of 2007 and the third quarter of 2009, and are not included in IPM modeling. If EPA is made aware of such units, the unit-level analysis required to establish such limits would be extremely complex, and could impact the ability of EPA to require the reductions as quickly as under other remedy approaches.

EPA is also taking comment on an alternative approach for setting emissions rate limits for those units which did not report a first, second, third, and fourth quarter of SO_2, NO_X, and/or a complete ozone season of NO_X emissions data to EPA during the 2007–2009 period. In this alternative approach, EPA could develop specific limits that would apply to a large group of units with varying characteristics. The numerous variables that contribute to differences in units" emissions rates complicate development of limits for a large group of units. Therefore, to ensure that all units in a broadly-defined group could achieve their rate limits, it would be necessary to either establish limits that are fairly weak so that the poorest-performing units could meet the requirements ("lowest-common-denominator" effect), or, design more stringent requirements but include provisions for exceptions to the requirements. At this time, EPA believes using IPM projections and source-specific judgments is preferable to the alternative of group-based limits, and seeks comments on this alternative.

Emissions rate limits for Phase II (2014 and onward). For EGUs in states that are in SO_2 group 1 (*i.e.*, the more stringent SO_2 group), EPA would further adjust (reduce) SO_2 emissions rates for certain EGUs that EPA projects would install FGD in modeling of the proposed remedy option (at less than $2000 per ton); for such units EPA would determine emissions rate limits at rates consistent with FGD operation. For other covered units, Phase II emissions rate limits would be the same as Phase I limits. Again, emissions rate limits would be determined based on the assumption that units operate all existing SO_2 and NO_X control equipment, and that the type of fuel used does not change from that used in determining the unadjusted rate limit. Note that for ozone season NO_X there is only one phase.

Emissions rate limits for new units. The emissions rate limits for covered new units would be set equal to the permit rates for these units.

EPA has calculated specific emissions rate limits for each existing unit that would be covered under this direct control remedy option. These unit-level emissions rate limits appear in a table entitled "Phase I and Phase II unit-level emissions rate limits" located in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rulemaking. More detailed description of the approach is also provided in the TSD. EPA is requesting comment on this approach for determining the emissions rate limits described in the TSD and on the limits themselves.

(2) Applicability

Applicability would be the same for all three remedies. Refer to section V.D.4 previously for detailed discussion on applicability.

(3) Monitoring and Reporting

Monitoring provisions would be the same for all three remedies. The direct control option would require minor changes to the reporting and record keeping requirements due to the need to collect information on both emissions rates and mass. The provisions would require complete, accurate measurement and timely reporting of emissions to assure accountability and provide public access to data. Refer to section V.D.4 previously for detailed discussion on monitoring and reporting requirements.

(4) Assurance Provisions

As discussed previously, starting in 2012, the direct control remedy alternative would include assurance provisions designed to assure that emissions in each covered state do not exceed the state's emissions budget with variability limit. The state's EGU emissions would not be permitted to

exceed the state budget with 1-year variability limit in any year (or ozone season, as applicable). Additionally, on a 3-year rolling average basis, the state's EGU emissions would not be permitted to exceed the budget with the 3-year variability limit (evaluated on an annual or ozone season basis, as appropriate). Furthermore, during 2012 and 2013, SO_2 emissions from EGUs in group 1 states (*i.e.*, the more stringent SO_2 group) would not be permitted to exceed the budget with the state's 2-year variability limit, evaluated as a 2-year rolling annual average. Section IV.E in this preamble lists each state's emissions budget, and section IV.F lists the 1-, 2-, and 3-year variability limits, as applicable.

Note that for EGUs in states that are in SO_2 group 2 (*i.e.*, the less stringent SO_2 group) and/or states required to reduce NO_X emissions, EPA would apply only the 1-year variability limit in 2012 and 2013, and not a 2-year variability limit. Because emissions would be evaluated against the 3-year variability limit on a 3-year rolling average basis, the application of the 3-year variability limit in 2014 would also serve to limit emissions in 2012 and 2013. For EGUs in SO_2 group 1 states (*i.e.*, the more stringent SO_2 group) EPA would apply a different 1-year SO_2 variability limit in 2012 and 2013 than for 2014 and later. Furthermore, in these group 1 states, EPA would apply a 2-year SO_2 variability limit in 2012 and 2013, and a 3-year limit for later years (section IV.F discusses why variability limits for the group 1 states would differ in 2012 and 2013).

If total EGU emissions in a state exceed either the state's budget with 1-year variability limit in any year, or budget with 3-year variability limit (or 2-year limit, as appropriate) on average, then each company with units in the state whose emissions in the state exceeded its share of the state budget with variability limit would be subject to a penalty for its share of emissions above the budget with variability limit.

In the State Budgets/Limited Trading remedy described previously, the proposed assurance provisions include an allowance surrender requirement. Those assurance provisions would require a company to surrender one allowance for each ton of the company's proportional share of the amount the state's EGU emissions exceed the budget with variability limit. This allowance surrender requirement is in addition to the trading program requirement to surrender one allowance for every ton emitted.

In the direct control alternative, however, allowances are not allocated to units therefore an allowance surrender requirement is not feasible. Instead, for this alternative, a company with emissions over its share of the budget with variability limit would be in violation of the CAA and subject to discretionary penalties. The tonnage amount of the company's violation, *i.e.*, the company's excess emissions under the assurance provisions, would be its proportional share of the amount that the state's EGU emissions exceed the budget with the variability limit. Each ton of the company's excess emissions, as well as each day in the averaging period, would be a violation.

In this direct control remedy alternative, a company's share of the state budget with variability limit would be determined using the same approach described in the State Budgets/Limited Trading option, previously. That approach is based on allowance allocations; although the direct control remedy would not allocate allowances to sources, this remedy would use the allocation method described in State Budgets/Limited Trading in determining a company's share of the state budget.

The assurance provisions would commence in 2012 for this direct control option. In contrast and for the reasons explained in section V.D.4, for the proposed State Budgets/Limited Trading remedy, EPA is proposing to start applying the assurance provisions in 2014. The combination of circumstances for State Budgets/Limited Trading—known locations of controls and a price on each ton emitted—provides greater certainty of where reductions will occur during 2012 and 2013 than would be provided by the direct control program. In contrast to the State Budgets/Limited Trading remedy, the direct control program does not put a price on emitting SO_2 or NO_X so does not provide that incentive to reduce emissions. Sources can increase generation, while meeting the emissions rate limits, and increase their emissions. For these reasons, the direct control program provides less certainty regarding the location of emissions in the short term. For this reason, EPA believes that it would be appropriate to apply the assurance provisions under this remedy option beginning in 2012.

EPA requests comment on these assurance provisions.

(5) Penalties

As explained previously, under this direct control remedy approach, each owner of EGUs within a covered state would be required to meet specified average emissions rate limits for SO_2 and/or NO_X emission for all of its EGUs. For the annual SO_2 or NO_X control programs, if a company were to exceed the applicable company-wide annual average rate limit, the company would be in violation of the CAA and subject to discretionary civil penalties.

The excess emissions of the owner's EGUs would be calculated as the EGUs" actual annual average emissions rate minus the applicable annual average emissions rate limit, with the difference multiplied by the EGUs" total actual annual heat input. Each ton of excess emissions, as well as each day in the averaging period (*e.g.*, 365 days for an annual program), would be a violation of the CAA. The maximum discretionary penalty under CAA Section 113 is $25,000 (inflation-adjusted to $37,500 for 2009) per violation.

For the ozone season NO_X program, the penalty provisions would work in the same manner described herein except on an ozone season basis rather than annual.

In addition, any company with EGU emissions exceeding its share of the state budget with variability limit for SO_2, NO_X annual or NO_X ozone season would also be in violation of the CAA and subject to discretionary civil penalties explained earlier in this section if, in any year (or ozone season, as applicable), the state as a whole exceeds its budget with variability limit (*see* description of assurance provisions, previously).

EPA requests comment on the penalty provisions.

c. How the Direct Control Remedy Is Consistent With the Court's Opinions

The direct control remedy option would implement the section 110(a)(2)(D)(i)(I) requirement that "emissions from sources that contribute significantly and interfere with maintenance in downwind nonattainment areas" be prohibited. It would do so by establishing for covered EGUs specific emissions rate limits, with company-wide within state averaging. Emissions rates in all states would be set on a unit-by-unit basis at levels such that, if the units operated at the levels assumed in determining the state budgets, total emissions from these units would sum to each state's emissions budgets without the variability limits. A company could average the emissions at its units within each state to meet specified within-the-state rate limits. This approach would directly limit emissions from EGUs in each covered state, providing assurance that emissions reductions would occur within each state consistent with the mandate of section 110(a)(2)(D)(i)(I).

Because individual EGUs would be required to meet specific emissions rate limits (with within-state company-wide averaging), this option would ensure that required controls and measures are installed and implemented within the state. The fact that emissions, after implementation of all controls required to meet the emissions rate limits, may vary based on the amount of generation in each state is not inconsistent with the section 110(a)(2)(D)(i)(I) requirement that all significant contribution and interference with maintenance be eliminated. As noted previously, changes in generation due to changing meteorology, demand growth, or disruptions in electricity supply from other units can all affect the amount of generation needed in a specific state and thus the baseline emissions from that state. Because baseline emissions are variable, emissions after the elimination of all significant contribution are also somewhat variable.

Further, any such variation in emissions would be limited. As with the State Budgets/Limited Trading option described previously, no state's EGU emissions would be permitted to exceed the state budget with variability limit in any year (or ozone season, as applicable). Nor would any state's EGU emissions be permitted, on average, to exceed the budget plus a specified portion of the state's variability limit, evaluated as a 3-year rolling annual (or ozone season) average (or, in SO_2 group 1 states during 2012–2013, a 2-year rolling annual average). Section IV in this preamble lists each state's emissions budget, and 1-, 2-, and 3-year variability limit, as applicable.

d. Electric Reliability Issues

The risk to electric reliability is considered low under the direct control remedy option. Specifically, the provisions for the variability limits and company averaging within each state help to alleviate electric reliability concerns. Therefore, EGUs are expected to be able to both comply with their emissions rate limits and reliably provide electricity to customers. EPA requests comment on electric reliability issues.

e. Why This Is Not the Preferred Option

As explained previously, EPA is requesting comment on the merits and weaknesses of this direct control remedy option. EPA did not include this remedy option in the proposed FIPs; however, we continue to consider this option and are taking comment on whether this option should be included in the FIPs. This option would provide assurance that companies in each state are meeting specific emissions rate limits and would also ensure that annual emissions from each state are capped. Additionally, the direct control option may be perceived as easy to understand and follow. Nonetheless, at this time, EPA believes the direct control option is inferior to the preferred approach. EPA requests comments on the validity of EPA's concerns regarding this option and alternative methods for addressing those concerns.

EPA modeling projects fewer emissions reductions under the direct control alternative than the proposed State Budgets/Limited Trading remedy. Additionally, the reductions would be achieved at a higher cost than the proposed remedy. *See* section V.E. for projected costs and emissions.

A direct control program must account for outliers, *e.g.*, units that can not install controls due to space limitations. EPA believes that the within-the-state company-wide averaging in the direct control alternative on which EPA is taking comment likely mitigates this concern. However, this averaging approach may put an owner with a small number of units within a state at a disadvantage compared to an owner with a larger number of units. EPA requests comment on this issue.

Within the direct control approach on which EPA is taking comment, the assurance provisions (which limit a company's emissions within a state to its share of the budget with the variability limit if the state's budget with variability limit is exceeded) may also put an owner with a small number of units at a disadvantage compared to an owner with a larger number of units within a state. EPA seeks comment on this issue.

A direct control program based on emissions rate limits does not cap annual emissions; if there is growth in fossil generation within a state, a rate-based approach alone could allow emissions increases. In the direct control approach on which EPA requests comment, the assurance provisions provide some assurance of achieving required reductions.

Notably, the direct control approach described herein restricts compliance options more than a trading approach. EPA generally believes that granting more flexibility to companies in meeting an emissions reductions goal results in the ability of those companies to meet that goal at a lower cost and decreases reliability risks in the electric power system. While some portion of this effect is captured in IPM modeling (*see* section V.E. for projected costs and emissions), some types of unforeseen innovations in technology, fuel switching, and management cannot be captured by modeling. Any potential innovations and resulting cost savings are more likely to be found and utilized in the presence of regulatory flexibility. Based on historical experience, EPA believes that the benefits offered by a flexible trading approach are large and should be considered qualitatively, even if they cannot be quantified. Many of these benefits would be foregone under the direct control approach.

E. Projected Costs and Emissions for Each Remedy Option

Emission and cost projections for the three remedies discussed previously come from the Integrated Planning Model (IPM), a dynamic linear programming model of electric generation in the contiguous U.S. For each remedy, projected costs relative to the base case appear in Table V.E–1. The following section explains these projections in light of how the remedies differ and how they were represented in the model. The emissions projections below comprise fossil generation above 25 megawatts of capacity, the units that would be subject to the rule. More detail on the modeling of costs and emissions can be found in the Regulatory Impact Analysis for the proposed Transport Rule and in the IPM Documentation.

TABLE V.E–1—PROJECTED INCREMENTAL COSTS DUE TO TRANSPORT RULE REMEDIES COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Billion 2006 dollars]

	2012	2014	2020	2025
Limited Interstate Trading (proposed)	3.7	2.8	2.0	2.0
Intrastate Trading	4.2	2.7	2.2	2.2
Direct Control	4.3	3.4	2.5	2.3

1. State Budgets/Limited Trading

The proposed remedy of State Budgets/Limited Trading was modeled with regional emissions caps beginning in 2012 and state-specific emissions limits beginning in 2014. The state-specific emissions limits represent state budgets plus 3-year average variability limits. Because banking early reductions beyond the budget levels is allowed, 2012 SO_2 reductions are greater overall than state budgets alone would require in that year. Table V.E–2 shows the projected emissions reductions from this remedy.

TABLE V.E–2—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.4	5.0	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.3	0.7
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

2. State Budgets/Intrastate Trading

Though based on the same state budgets as State Budgets/Limited trading, the alternative remedy of State Budgets/Intrastate Trading costs approximately 0.5 billion 2006 dollars more in 2012 and achieves slightly more SO_2 reduction in 2012 (and slightly less in 2014), as Table V.E–3 shows. In modeling this remedy, each state's emissions were restricted to the state budget without variability. Without the opportunity for even limited trading of allowances across state borders, more banking was projected in some states. In other states, more immediate emissions reductions (relative to the base case) are projected so that state budgets are met exactly. Both of these factors drive 2012 costs higher than those of limited interstate trading and lead to slightly greater SO_2 reductions in 2012.

TABLE V.E–3—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE INTRASTATE TRADING ALTERNATIVE REMEDY COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.2	5.2	7.2	2.7	4.5
Annual NO_X	2.0	1.3	0.7	2.0	1.2	0.8
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

3. Direct Control

The direct control alternative remedy consists of source-specific emissions rate limits commensurate with those used in the derivation of state budgets (see sections IV.D and IV.E). To represent assurance provisions, the emissions from each state were also constrained to the state's budget plus 3-year average variability limit beginning in 2012. For states with more stringent SO_2 budgets in 2014, FGD retrofits were required on units shown to have cost-effective retrofit opportunities at $2,000 per ton.

Compared to the proposed remedy of State Budgets/Limited Trading, the direct control alternative costs approximately 0.6 billion 2006 dollars more and results in less SO_2 reduction in 2012, as shown in Table V.E–4. Unlike remedies allowing banking for early reductions, the direct control alternative does not result in reductions below state budgets in 2012. At the same time, meeting specific rate requirements for every source means there is little incentive to achieve additional reductions with fuel switching.

TABLE V.E–4—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE DIRECT CONTROL ALTERNATIVE REMEDY COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.8	4.6	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.2	0.8
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

4. State-Level Emissions Projections

Tables V.E–5, V.E–6, and V.E–7 show projected emissions at the state level from all EGUs in 2014.

TABLE V.E–5—PROJECTED STATE-LEVEL [105] SO_2 EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
Alabama	322,362	172,430	162,103	172,430
Connecticut	6,160	3,234	3,208	3,208
Delaware	8,079	9,185	8,974	9,110
District of Columbia	176	179	180	180
Florida	194,723	139,805	159,120	135,366
Georgia	173,257	92,375	89,706	92,375
Illinois	200,484	164,741	156,049	163,902
Indiana	804,425	240,730	267,564	239,852
Iowa	163,966	102,419	102,096	106,569
Kansas	65,125	51,248	52,501	53,275
Kentucky	739,595	123,837	128,318	123,833
Louisiana	94,866	94,933	92,647	96,390
Maryland	45,294	45,449	45,304	45,752
Massachusetts	17,265	10,306	8,595	8,909
Michigan	275,961	173,828	188,796	172,986
Minnesota	62,033	49,413	49,836	58,925
Missouri	500,649	192,645	190,815	190,532
Nebraska	115,695	75,095	73,219	75,061
New Jersey	39,721	16,562	14,935	16,569
New York	142,762	58,455	53,373	58,455
North Carolina	140,924	97,262	109,385	97,262
Ohio	841,199	232,964	269,547	228,514
Pennsylvania	974,644	154,852	183,276	154,855
South Carolina	156,200	131,232	123,525	131,232
Tennessee	600,071	106,767	100,012	94,078
Virginia	136,573	58,329	51,633	58,330
West Virginia	496,307	127,646	147,580	127,646
Wisconsin	117,397	85,933	87,328	83,709

TABLE V.E–6—PROJECTED STATE-LEVEL ANNUAL NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
Alabama	118,955	61,793	61,618	61,865
Connecticut	7,991	8,003	7,986	8,004
Delaware	5,790	6,176	6,126	6,074
District of Columbia	933	946	948	948
Florida	196,373	126,155	126,065	94,646
Georgia	48,267	44,461	44,462	44,611
Illinois	80,451	57,589	54,773	57,949
Indiana	201,027	112,502	112,721	108,675
Iowa	68,259	53,072	50,146	52,069
Kansas	79,018	40,020	40,074	39,558
Kentucky	148,551	71,371	71,692	69,882
Louisiana	45,551	37,255	36,594	37,164
Maryland	36,089	36,326	33,778	36,532
Massachusetts	12,650	13,047	12,219	13,064
Michigan	98,941	65,066	65,973	67,525
Minnesota	55,283	38,969	39,114	38,039
Missouri	83,019	67,475	61,679	67,648
Nebraska	53,029	35,101	34,105	35,457
New Jersey	27,127	23,377	23,358	23,338
New York	36,352	36,592	34,538	36,597
North Carolina	62,608	60,516	54,639	60,517
Ohio	164,947	99,358	95,997	100,886
Pennsylvania	204,950	123,629	123,095	123,409

[105] The modeling presented in Tables V.E–5, V.E–6, and V.E–7 differs from the proposed Transport Rule because the District of Columbia (DC) is included neither in the annual SO_2 and NO_X requirements nor in the ozone season NO_X requirement. Modeled units in DC include two small facilities, one of which has only units below 25 MW capacity. EPA believes the addition of emissions limits in DC would have little to no effect on the modeling results.

TABLE V.E–6—PROJECTED STATE-LEVEL ANNUAL NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014—Continued

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
South Carolina	47,742	34,735	33,781	34,616
Tennessee	68,914	28,212	26,874	28,873
Virginia	37,485	35,805	35,745	37,004
West Virginia	100,095	48,180	48,987	50,555
Wisconsin	54,515	41,875	42,498	42,450

TABLE V.E–7—PROJECTED STATE-LEVEL OZONE-SEASON NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
Alabama	26,995	26,727	26,552	26,823
Arkansas	21,667	12,080	12,095	12,077
Connecticut	3,446	3,453	3,446	3,446
Delaware	2,367	2,669	2,671	2,613
District of Columbia	391	397	397	398
Florida	94,686	62,221	62,037	48,170
Georgia	21,947	19,686	19,688	19,749
Illinois	24,167	24,930	22,833	24,701
Indiana	49,023	47,477	47,813	45,589
Kansas	34,537	17,470	17,590	17,282
Kentucky	29,927	29,376	29,671	29,107
Louisiana	21,443	17,388	17,106	17,308
Maryland	15,307	15,454	14,275	15,512
Michigan	29,934	27,778	28,052	29,415
Mississippi	16,955	8,524	8,526	8,522
New Jersey	10,470	10,324	10,295	10,260
New York	17,257	17,493	16,518	17,491
North Carolina	27,018	26,117	23,459	26,004
Ohio	44,753	41,141	40,051	42,789
Oklahoma	38,546	24,471	24,471	24,426
Pennsylvania	53,263	53,102	52,692	52,586
South Carolina	15,730	14,818	14,666	14,753
Tennessee	12,021	11,868	10,955	12,007
Texas	79,572	68,769	68,874	67,832
Virginia	16,264	15,397	15,289	16,093
West Virginia	24,339	20,249	21,466	21,500

F. Transition From the CAIR Cap and Trade Programs To Proposed Programs

This proposed Transport Rule would replace the CAIR rule and its associated trading programs. This section elaborates on some of the areas of the CAIR program that would need to be addressed in the transition to the new program. EPA is taking comment on how the transition would occur.

1. Sunsetting of CAIR, CAIR SIPs, and CAIR FIPs

The CAIR, CAIR SIPs, and CAIR FIPs would be replaced entirely by the Transport Rule provisions. If this proposed Transport Rule is finalized in 2011, the CAIR, CAIR SIPs, and CAIR FIPs would sunset at the completion of all 2011 control period activities.

In order to implement the sunsetting of the CAIR and CAIR FIPs, the proposed rule includes several revisions of the CAIR, §§ 51.123 and 51.124, and the CAIR FIPs, §§ 52.35 and 52.36. First, sunsetting the CAIR and CAIR FIPs in 2011 would mean that the requirements of the CAIR and CAIR FIPs would not apply to control periods after 2011. Specifically, the CAIR would be revised to rescind, with regard to any control period beginning after December 31, 2011, the findings that states must revise their SIPs to meet CAIR requirements. Similarly, the CAIR FIPs would be revised to state that, with regard to any post-December 31, 2011 control period, CAIR FIP requirements would not be applicable.

Second, the sunsetting in 2011 would mean that the CAIR trading programs would not continue past 2011. Consequently, the proposed revisions of the CAIR and CAIR FIPs would state that, with regard to any post-December 31, 2011 control period, the Administrator would not carry out any of the functions established for the Administrator in the CAIR model trading rule, the CAIR FIPs, or any state trading programs approved under the CAIR.

Third, the sunsetting in 2011 would mean that CAIR allowances allocated for control periods after 2011—which have already been recorded by the Administrator in the Allowance Management System compliance accounts of sources in many states—would not be usable in the CAIR trading programs for control periods ending before 2012. Specifically, under the existing CAIR trading programs, a source that fails to hold sufficient allowances to cover emissions for the 2011 control period (whether annual or ozone season) must provide for surrender to the Administrator three allowances (one as an offset and two as an automatic penalty) allocated for the 2012 control period for every one

allowance that was not held as required. However, consistent with the proposed termination of the CAIR trading programs for control periods after 2011, EPA believes that allowances allocated for such control periods (*e.g.*, 2012 allowances) should not be usable for any purpose. In any event, because such allowances would have little or no market value, their deduction would impose little or no cost on the party holding them. Consequently, the proposed revisions of the CAIR and CAIR FIPs would state that the Administrator would not deduct, for excess emissions, any CAIR allowances allocated for control periods in 2012 or any year thereafter. These revisions would ensure that no CAIR allowances allocated for post-2011 control periods would be used as an offset of, or an automatic penalty for, excess emissions.

As a result of these proposed revisions of the CAIR and CAIR FIP rules, there would be no offset or automatic penalty deducted for a source that failed to hold sufficient allowances to cover its 2011 control period emissions unless the state SIPs are revised. In order to preserve the deductions for offsets and automatic penalties for 2011 control periods, the CAIR SIPs for most states (*i.e.*, 20 out of the 28 states subject to at least one CAIR trading program) would need to be modified and the modified CAIR SIPs would need to be approved by the EPA —-before EPA conducts the process of determining source compliance after the allowance transfer deadline for the 2011 control periods —in order to change the allocation year of the allowances required to be deducted (*e.g.*, from allowances allocated for 2012 to allowances allocated for 2011). Although EPA's past experience with trading programs strongly suggests that few sources would be out of compliance with the requirement to hold allowances covering 2011 emissions, all of these CAIR SIPs would have to be revised because there is no way to predict which few sources in which few states might be out of compliance in 2011 and the process of revising SIPs is too long to be started while EPA is still determining compliance. In fact, when states needed to revise their SIPs to include the existing requirements of CAIR and submit the revised SIPS to the Administrator, EPA found that states needed up to 3 years to develop and submit SIP revisions, and EPA needed about 6 months to act on the SIP revisions. In light of this experience with SIP revisions under CAIR, EPA believes that it would highly unlikely that all, or even most, state CAIR SIPs could be revised, submitted, and approved in time—even if the SIP revision process were started when a final Transport Rule is promulgated—to change what allowances were to be used for offsets and automatic penalties for excess emissions for the 2011 control periods.

Moreover, any excess emissions for the 2011 control periods would be violations of the state SIPs (or of CAIR FIPs in those states with CAIR FIPs) and of the Clean Air Act and, therefore would be subject to discretionary civil penalties under CAA Section 113. Each ton of excess emissions, and each day in the control period involved (*i.e.*, 365 days for annual control periods and 153 days for the ozone season control period), would be a violation, with a maximum penalty of $25,000 (inflation adjusted to $37,500) per violation. In determining what level of discretionary civil penalties to impose on a source that has excess emissions violations, EPA routinely considers, among other things, whether, and if so what level of, other penalties (*e.g.*, automatic excess emissions penalties) have already been imposed for the same violations, as well as any economic benefit of noncompliance (*e.g.*, the avoidance of the cost of surrendering allowances to cover emissions). See, *e.g.*, 42 U.S.C. 7413(e)(1) (including, as penalty assessment criteria, "payment by the violator of penalties previously assessed for the same violation" and "the economic benefit of noncompliance"). Consequently, EPA believes that, regarding the CAIR 2011 control periods (both annual and ozone season) for which it is not feasible to change the offset and automatic penalty provisions to make them workable, the potential for assessment of significant, discretionary civil penalties would provide a strong incentive for compliance with the allowance-holding requirement and avoidance of excess emissions.

In addition to the previously-described, proposed revisions to §§ 51.123, 51.124, 52.35, and 52.36, certain provisions in part 52 that reflect, state by state, the CAIR SIP revisions and CAIR FIP requirements applicable to each state would need to be revised to implement the sunsetting of the CAIR, CAIR SIPs, and CAIR FIPs. However, the timing for proposal and adoption of revisions to part 52 is necessarily different for the part 52 provisions addressing CAIR SIP revisions and those addressing revisions of the CAIR and the CAIR FIPs themselves.

The part 52 provisions addressing CAIR SIP revisions for the individual states reflect EPA's approval of CAIR SIP revisions adopted and submitted to EPA by the respective states. The first step toward sunsetting those part 52 provisions would be that, if and after the proposed Transport Rule was finalized, the respective states would change their SIPs in order to, among other things, make the CAIR provisions in the SIPs inapplicable to any control period that starts after December 31, 2011. After the submittal by the respective states of these SIP revisions, EPA would review and approve such changes. Consequently, the rule text approving such CAIR SIP revisions would not be included in either the proposed Transport Rule or any final rule based on the proposed Transport Rule, but rather would be proposed and adopted only after the respective states revised their SIPs. As EPA did when transitioning from the NO_X Budget Trading Program to the CAIR NO_X ozone season trading program, EPA will work with states to transition from state CAIR programs to their replacement FIPs or state SIPs. This assistance will be provided through meetings or workshops, web-based references, one-on-one assistance through the EPA regions, etc.

In contrast, the part 52 provisions adopting CAIR FIPs for individual states could be revised, as part of the proposed Transport Rule, to sunset these CAIR FIPs because no state action would be required to accomplish this sunsetting. EPA proposes to revise each state-specific part 52 provision adopting a CAIR FIP—whether for NO_X annual or ozone season emissions or SO_2 emissions—to add a paragraph stating that: with regard to any control period starting after December 31, 2011, the respective CAIR FIP would not apply and the Administrator would not carry out any of the functions set forth for the Administrator in the trading program rules under the CAIR FIP; and the Administrator would not deduct for excess emissions any CAIR allowances allocated for 2012 or any year thereafter. The new, added rule text would be very similar to the proposed rule text revisions to §§ 52.35 and 52.36 and would be essentially the same for each of these state-specific Part 52 provisions. EPA has included in the proposed Transport Rule the proposed rule text making these state-by-state revisions for Delaware, District of Columbia, Indiana, Louisiana, Michigan, New Jersey, Tennessee, Texas, and Wisconsin. These provisions revise all of the state-specific Part 52 provisions adopting CAIR FIPs provisions to make the CAIR FIPs inapplicable to any control period that

starts after December 31, 2011 and state that the Administrator would not carry out any functions under the CAIR trading programs during any such control period and would not use any CAIR allowances allocated for any such control period.

2. Change in States Covered

The states covered by the proposed Transport Rule differ slightly from states covered by the CAIR. Namely, as compared with the states covered by the CAIR NO_X ozone season trading program, the states covered by the proposed Transport Rule NO_X ozone season trading program would include Georgia, Kansas, Oklahoma, and Texas and would not include Iowa, Massachusetts, Missouri, and Wisconsin. Further, as compared with the states covered by the CAIR NO_X annual and SO_2 trading programs, the states covered by the proposed Transport Rule NO_X Annual and SO_2 trading programs would include Connecticut, Kansas, Massachusetts, Minnesota, and Nebraska and would not include Mississippi and Texas. (*See* also the discussion in section IV.D. regarding the possibility that the states to which this rule would apply could expand.)

Consequently, sources in some states that would be covered by the proposed Transport Rule would have new allowance holding requirements beginning in 2012, but would not have been subject to the CAIR trading programs. Conversely, sources in some states covered by the CAIR or CAIR FIPs would not be subject to the proposed Transport Rule. To the extent that the CAIR reductions were needed or relied upon to satisfy other SIP requirements, states might need to find alternative ways to satisfy requirements for their SIPs. EPA will work with individual states to identify state-specific options to ensure that necessary reductions needed for other SIP requirements can continue.

3. Applicability, CAIR Opt-ins and NO_X SIP Call Units

Except for the changes in the states covered, the general applicability provisions of the proposed Transport Rule would be essentially the same as the CAIR general applicability provisions, with a few exceptions. First, the proposed Transport Rule does not allow any units to opt into the trading programs. In contrast, under CAIR, states could elect to allow boilers, combustion turbines, and other combustion devices to opt into the CAIR trading programs under opt-in provisions specified by EPA, and a number of states adopted these opt-in provisions. However, currently no units have opted into the CAIR trading programs, and, even in the Acid Rain Program, where opt-in provisions have been in place since 1995, very few units have actually opted in.

Second, under the CAIR trading programs, a state subject to the NO_X SIP Call was allowed to expand the applicability of the CAIR NO_X ozone season trading program in the state in order to include all units subject to the NO_X Budget Trading Program (NBP) under the NO_X SIP Call and thereby to continue to meet the state's NO_X SIP Call requirements. Fourteen states chose to expand the CAIR NO_X ozone season applicability in this way, while six states chose not to expand the applicability and instead to meet their NO_X SIP Call obligations in other ways. In expanding the applicability of the CAIR NO_X ozone season trading program, the fourteen states brought into the program large industrial boilers and turbines (with maximum design heat input greater than 250 mmBtu/ hr) and, in some cases, smaller electric generating units (serving generators with nameplate capacity of 15 through 25 MWe), and generally the CAIR NO_X ozone season budgets in these states were increased to account for these additional sources. In contrast, the proposed Transport Rule NO_X ozone season trading program would not allow for expansion of applicability to include these units currently covered only by the NBP.

There are several factors underlying this difference between the proposed Transport Rule and the CAIR. First, in determining which states are contributing significantly or interfering with maintenance of the ozone NAAQS, the Transport Rule does not cover some states subject to the NO_X SIP Call (*i.e.*, Massachusetts, Missouri, and Rhode Island). Further, the six states that chose under the CAIR to require the necessary NO_X SIP Call reductions through provisions other than the CAIR NO_X ozone season program would not likely be interested in expanding applicability under the Transport Rule NO_X ozone season trading program to cover these units. In addition, EPA has determined that these units as a group did not actually reduce emissions as a result of the NBP or through their inclusion in the CAIR NO_X ozone season trading program. In fact, their current emissions rates are nearly identical to what they were before the NBP started. Moreover, these units as a group had allowances that they did not need for compliance and that were available for trading to other affected units. The Transport Rule, as proposed, does not include these units and does not include provisions for allowing states expand applicability to include them. EPA is taking comment on this approach.

4. Early Reduction Provisions

Substantial emissions reductions have occurred as a result of the CAIR programs. These reductions are greater than were expected when the rule was promulgated. This is evidenced in the banks of allowances that exist in each of the CAIR programs.

a. SO_2 Allowance Bank

The bank of Title IV allowances was more than 12 million tons at the end of 2009. This bank is the result of emissions reductions for Title IV where allowances are used for compliance with the requirement to hold allowances covering emissions and early reductions for the CAIR SO_2 trading program. EPA believes that it is advantageous to minimize sources" use of the Title IV allowance bank if possible and recognizes that, if the bank has minimal future market value, there may be incentive to use as many banked allowances as possible. EPA tracks the SO_2 emissions on a quarterly basis and makes the information available to the public at *http://epa.gov/airmarkets/quarterlytracking.html.*

EPA evaluated whether the Title IV allowance bank could be used in the proposed Transport Rule SO_2 program in any way. One idea presented to EPA was to distribute Transport Rule SO_2 allowances based on the number of Title IV allowances a source has in its bank at the completion of compliance in the last year of the CAIR SO_2 program, thereby incentivizing minimal use, by sources, of Title IV allowance banks and encouraging continued emission control. EPA is concerned that the approach would have significant legal risk for two reasons. First, the Court is likely to view the approach as imposing a significant burden on the use of Title IV allowances and therefore as modifying the authorization provided by such allowances. Second, the Court is likely to view the approach as not related to, much less necessary for, implementation of the section 110(a)(2)(D)(i)(I) mandate to eliminate significant contribution and interference with maintenance. EPA chose instead, under the proposed Transport Rule, to distribute Transport Rule SO_2 allowances in a manner directly linked to its calculation of each state's significant contribution and interference with maintenance and not to use Title IV allowances as a basis for distributing the new Transport Rule allowances. EPA is confident that the approach

selected is consistent with the Court's opinion in *North Carolina* v. *EPA*, 531 F.3d 896, 922 (D.C. Cir. 2008). (Additional information on this approach can be found in the docket.) EPA requests comment on whether or not an allowance distribution approach based on the number of Title IV allowances in a given source's account would be consistent with the Court opinion.

EPA proposes that the Transport Rule provisions not allow the use of Title IV allowances either as the basis for allocating Transport Rule SO_2 allowances or directly for compliance with allowance-holding requirements. Thus, there would be no SO_2 allowances carried over into the new SO_2 program. Title IV allowances continue, of course, to be used for compliance with the Acid Rain Program.

b. NO_X Allowance Banks

Assuming that NO_X emissions in 2010 and 2011 are equal to what they were in 2009, the CAIR NO_X ozone season bank would contain over 600,000 allowances (which would equal more than 100 percent of the total of the state budgets under the proposed Transport Rule NO_X ozone season program for 2012), and the CAIR NO_X annual bank would contain about 720,000 allowances (which would equal nearly 50 percent of the total of the state budgets under the proposed Transport Rule NO_X annual program for 2012), after completion of true-up of allowance holdings and emissions for 2011. Estimates of the size of the banks have only recently been made based on reported 2009 emissions data, and the impacts of different approaches to handling the banks have not yet been modeled. However, EPA is concerned about the potential impacts of these approaches. On one hand, allowing pre-2012 CAIR NO_X allowances and CAIR NO_X ozone season allowances to be used in the proposed Transport Rule NO_X programs, and thereby ensuring that the allowances would continue to have some market value in the future, would promote the continuation—in 2010 and 2011—of the reductions that occurred in 2009 under the CAIR NO_X programs. On the other hand, the amounts of the banks are so large that they might significantly reduce the amount of emissions reductions that would otherwise be achieved in the proposed Transport Rule NO_X programs, particularly in the earlier years (*e.g.*, 2012 and 2013).

EPA has identified several possible approaches for handling banked pre-2012 CAIR NO_X allowances in the Transport Rule NO_X programs. The first approach might be to allow all such banked CAIR allowances to be brought into the Transport Rule NO_X programs, make the assurance provisions effective starting in 2012, and rely on the assurance provisions to ensure that each state continues to eliminate all of the significant contribution and interference with maintenance that EPA has identified in today's proposal. The banked CAIR allowances would be usable, and the assurance provisions would apply, in all states in the Transport Rule NO_X programs. However, EPA is concerned that some parties may view this approach as having the effect of allowing sources that were advantaged by the development of state budgets using fuel adjustment factors—the use of which was reversed by the Court in *North Carolina*, 531 F.3d at 918–21—and that still hold part of their allocated allowances to continue have an advantage in the Transport Rule NO_X trading programs. These concerns may be mitigated somewhat by the fact that even though the methodology used to divide the regional budget into state budgets used fuel factors, states had the flexibility to allocate allowances however they wished. EPA takes comment on the extent to which states have allocated differently and the extent to which this may mitigate concerns about allowing the use of banked CAIR NO_X allowances in the Transport Rule annual NO_X and ozone season NO_X trading programs.

The second approach might be to allow only a limited amount of banked pre-2012 CAIR allowances to be brought into the Transport Rule programs. This could be accomplished by allowing all such banked allowances to be used, but at a tonnage authorization level significantly lower than one ton per allowance, in the Transport Rule NO_X programs. However, while severely limiting the tonnage authorization of banked allowances that is allowed into the new programs would limit any advantage realized by sources that received fuel-adjustment-factor-based CAIR allowance allocations, this would also limit any beneficial impact that bringing CAIR allowances into the new programs might have on preserving emissions reductions in 2010 and 2011.

The third option might be to try to factor the bank into the calculation of state budgets by reducing the state budgets to take account of the banked pre-2012 CAIR allowances. This might allow these allowances to be used in the Transport Rule NO_X programs without adversely affecting the states' elimination of the part of significant contribution and interference with maintenance that EPA has identified. However, this approach would not be feasible because EPA cannot determine in advance in which states banked pre-2012 CAIR allowances might be used and so would not know which state budgets should be adjusted and what amount of adjustment would be necessary.

A final approach would simply be to not allow the use of any banked pre-2012 CAIR allowances in the Transport Rule NO_X programs. This approach would avoid the potential legal and practical problems raised by the other approaches and is the approach proposed by EPA. EPA requests comment on the proposed approach, the previously-discussed alternative approaches, and any other possible approaches for handling banked pre-2012 CAIR allowances in the Transport Rule NO_X programs.

5. Source Monitoring and Reporting

Monitoring and reporting using 40 CFR part 75 provisions is required for all units subject to the CAIR programs and would also be required for all units subject to the proposed Transport Rule programs. In states covered by both the CAIR and the proposed Transport Rule, units would generally have no changes to their monitoring and reporting requirements and would continue to monitor and submit reports as they have under the CAIR. The exceptions are units in: CAIR states subject to CAIR NO_X ozone season requirements but NO_X and SO_2 annual requirements under the proposed Transport Rule; or CAIR states subject to CAIR NO_X annual and ozone season and SO_2 requirements but only to NO_X ozone season requirements under the proposed Transport Rule. These exceptions could arise, in part, because under Part 75 some units (*i.e.*, non-Acid Rain units) that are in NO_X ozone season, and not NO_X annual, programs have the option of monitoring and reporting NO_X emissions for just the ozone season.

Units in the following states monitor and report both SO_2 and NO_X year-round under the CAIR and would continue to do so under the Transport Rule: Alabama, Delaware, the District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. Non-Acid Rain units in Arkansas are currently required to monitor and report NO_X in the ozone season under the CAIR and would continue to be required to do so under the proposed Transport Rule.

Non-Acid Rain units in Connecticut and Massachusetts (about 15 units total) that currently monitor and report NO_X in the ozone season would need to monitor and report NO_X and SO_2 on an annual basis under the proposed Transport Rule.

Non-Acid Rain units in Mississippi (about 4 units) and Texas (about 52 units) are currently monitoring and reporting NO_X and SO_2 year-round and under the proposed Transport Rule would be required to monitor and report NO_X in the ozone season. (All of these units burn natural gas and emitted approximately 12 tons of SO_2 in 2009.)

In states not covered by the CAIR but covered by the proposed Transport Rule, some units would have to meet new monitoring and reporting requirements under part 75. Kansas, Minnesota, and Nebraska are not covered by the CAIR and are covered by the Transport Rule, and units there would need to monitor and report NO_X and SO_2 emissions year-round. Oklahoma is not covered by the CAIR and is covered by the Transport Rule, and units there would need to monitor and report NO_X in the ozone season. There are about 34 non-Acid Rain units total in Kansas, Nebraska and Oklahoma not monitoring and reporting under Part 75 that would need to begin to do so. Most of these units are simple-cycle combustion turbines used in the ozone season as peaking units and would likely be able to utilize the Low Mass Emissions or Appendix D and E methodologies in 40 CFR part 75, which do not require a continuous emissions monitoring system (CEMS). The circulating fluidized bed (CFB) units in Oklahoma (about 4 units) that burn coal are already monitoring and reporting under 40 CFR part 60, subpart Da, which requires an SO_2, NO_X and CO2/O2 (diluent) CEMS. These boilers would only have to add a flow monitor and upgrade the automated data acquisition and handling system. Non-Acid Rain units in Minnesota (about 20 units) would also need to monitor and report, but were already doing so under the CAIR before the CAIR was stayed in Minnesota (74 FR 56721, November 3, 2009); therefore, they would simply have to reactivate those monitoring systems.

Units that have not been covered by part 75 monitoring and reporting in the past would likely have less than one year to install, certify, and operate the required monitoring systems. EPA believes that these units would reasonably be able to comply with this requirement because the monitoring equipment needed is not extensive or is largely in place already for the purpose of meeting other requirements. Quality assurance and reporting provisions and data system upgrades may be necessary, but there would be sufficient time to accomplish this.

G. Interactions With Existing Title IV Program and NO_X SIP Call

1. Title IV Interactions

Promulgation of a Transport Rule would not affect any Acid Rain Program requirements. Any Title IV sources that are subject to final Transport Rule provisions would still need to continue to comply with all Acid Rain provisions. Acid Rain requirements are established independently in Title IV of the Clean Air Act and would not be replaced by the Transport Rule. In contrast with the CAIR, the proposed Transport Rule would not allow Title IV SO_2 allowances to be used in the Transport Rule program. Similarly, Transport Rule SO_2 allowances would not be useable in the Acid Rain Program. Title IV SO_2 and NO_X requirements will continue to apply independently of the Transport Rule provisions. The Transport Rule program as proposed has no opt-in provisions, so no sources, including any that have opted into the Acid Rain Program would be able to opt-in to the Transport Rule program.

Compliance with the Transport Rule would reduce SO_2 emissions in the Transport Rule states below the 2010 Title IV cap. So, as sources complied with the Transport Rule, emissions would go down and with them so would the demand for Title IV allowances. Therefore, the Title IV allowance prices are expected to be very low once the Transport Rule is finalized; some analysts suggest a price of nearly zero. Acid Rain sources will still be required to comply with Title IV requirements, including the requirement to hold Title IV allowances to cover emissions at the end of a compliance year.

There would likely be changes to emissions at some Acid Rain sources outside of the Transport Rule area as a result of the transition from CAIR to the Transport Rule. Namely, emissions at some non-Transport Rule Acid Rain sources may increase because of the change in the Title IV allowance price. This would be expected to occur mainly in the states that border the Transport Rule states. Overall, SO_2 emissions from these non-Transport Rule Acid Rain sources would be expected to increase approximately 237,000 tons each year if the Transport Rule is implemented compared to what they would have been in the absence of the Transport Rule. There is more discussion of this effect in section IV.D.

2. NO_X SIP Call Interactions

States affected by both the NO_X SIP Call and any final Transport Rule will be required to comply with the requirements of both rules. The Transport Rule does not preempt or replace the requirements of the NO_X SIP Call. However, the proposed Transport Rule ozone season program would achieve the emissions reductions required by the NO_X SIP Call from EGUs greater than 25 MW in nearly all NO_X SIP Call states. The NO_X SIP Call states used the NO_X Budget Trading Program (NBP) to comply with the NO_X SIP Call requirements for EGUs serving a generator with a nameplate capacity greater than 25 MW and large non-EGUs with a maximum rated heat input capacity greater than 250 MMBTU/hr. (In some states, EGUs smaller than 25 MW were also part of the NBP as a carryover from the Ozone Transport Commission NO_X Budget Trading Program.) EPA stopped administering the NBP after the 2008 ozone season control period activities, and states used another mechanism to comply with the NO_X SIP Call requirements.

Many of the states using the NBP used the CAIR NO_X ozone season trading program to replace the NBP. To address NO_X SIP Call requirements, fourteen NO_X SIP Call states chose to expand the CAIR NO_X ozone season applicability to include all NBP-affected units. EPA has analyzed the effect of allowing states to expand their CAIR NO_X ozone season applicability and consequently their CAIR NO_X ozone season budgets to include the additional non-CAIR affected NBP units. In 2009, the additional units emitted about half of the amount of allowances added to the CAIR NO_X ozone season budgets for them. The remaining allowances are available for the sources to trade to other affected units. As a group, these units did not reduce their NO_X emissions or their NO_X emissions rates as a result of their inclusion in the CAIR NO_X ozone season program. If EPA were to allow them to be part of the Transport Rule NO_X Ozone Season Program, and if states were allowed to increase the Transport Rule NO_X Ozone Season Budgets by the amounts allowed under the NBP and CAIR for these units, a state's ability to eliminate the part of significant contribution and interference with maintenance that EPA has identified in today's proposal could be jeopardized. One option considered that could possibly address concerns about still being able to address significant contribution and interference with

maintenance would be to require the budget increase to be much less than allowed under the NBP and CAIR. For example, the units' 2009 emissions (or 2012 projected emissions if they are required to install controls for another program) could be used to determine the budget increase and the elimination of emissions causing significant contribution and interference with maintenance might be able to be preserved. It is likely the budget changes would not be consistent across states as each state's impact would have to be considered individually. EPA is proposing to not allow the expansion of the applicability of the Transport Rule.

Therefore, the NBP states would need to achieve their NO_X SIP Call emissions reductions another way in order to continue to comply with the NO_X SIP Call. If EPA promulgates a final rule that does not allow the expansion of the Transport Rule to NBP units, any state that allowed these units to participate in the CAIR NO_X Ozone Season Program would need to submit a SIP revision to address their NO_X SIP Call requirement for the reductions.

States that were part of the CAIR NO_X ozone season program or the NBP that are not part of a final Transport Rule ozone season program would need to submit SIP revisions that address the NO_X SIP Call requirements for any emissions reductions that were part of either the CAIR NO_X ozone season program or the NBP and would not continue to be addressed some other way. EPA will work with states to ensure that NO_X SIP Call obligations continue to be met.

VI. Stakeholder Outreach

In early 2009, EPA began its efforts to coordinate activities with state regulatory partners and other stakeholders on the new transport rule to replace CAIR. To establish open lines of communication and ensure transparency in the regulatory process, EPA participated in a series of "listening sessions" in March and April, 2009 with states, nongovernmental organizations, and industry. EPA also participated in tribal teleconferences. The same agenda was set for each of the ten meetings. Meeting notes were developed and distributed for concurrence and to ensure accuracy. Subsequent to these sessions, EPA received post-meeting comments and additional detailed suggestions and analyses on ways to address some of the issues that the court cited, most notably from state regional organizations in the eastern U.S. All the stakeholder-related materials may be found in the EPA docket for the transport rule (EPA–HQ–OAR–2009–0491).

Following the remand of CAIR to EPA in December 2008, 17 states in the East and Midwest, under the umbrellas of the OTC and Lake Michigan Air Directors Consortium (LADCO) with support from southeastern states, worked to develop recommendations for EPA to consider in crafting a new transport rule to replace CAIR. The comprehensive framework presented the consensus approach the states reached but noted that certain regional differences would be addressed in separate letters with additional recommendations and supporting materials.

EPA has considered and appreciates all the ideas and recommendations provided by the states. We are employing the technical work that they submitted as part of the data set we are using in this and later transport rules.

Topics addressed in the listening sessions, where EPA asked stakeholders and regulatory partners for their thoughts on particular issues, included:

- Analysis and baselines.
- Linkages between a state's significant contribution and downwind nonattainment/interference with maintenance.
- Remedies.
- Attainment planning.
- Other areas.

EPA continued to provide updates to regulatory partners and stakeholders through monthly conference calls with states, hosted by, *e.g.*, NACAA, as well as industry and NGO conferences where EPA directors often made presentations.

Several of the options presented in this proposal were influenced by feedback received from stakeholders and regulatory partners, including:

- 2012 baseline used in the calculation of each state's significant contribution and interference with maintenance.
- The "tiered" approach to SO_2 emissions reductions requirements.
- Threshold (1 percent of the NAAQS) used for linking upwind areas to downwind nonattainment and maintenance receptors.
- Approach used to give independent meaning to the interfere with maintenance prong of section 110(a)(2)(D)(i)(I).
- Level of reductions required.
- Use of limited interstate trading.
- Correlated and coordinated requirements and timing for the power industry.

EPA looks forward to the public comment period of this rulemaking and is committed to establishing and maintaining close working relationships with a broad range of public and private sector organizations.

VII. State Implementation Plan Submissions

A. Section 110(a)(2)(D)(i) SIPs for the 1997 Ozone and $PM_{2.5}$ NAAQS

All states have an obligation to submit SIPs that address the requirements of CAA section 110(a)(2) within 3 years of promulgation or revision of a NAAQS. With respect to the 1997 ozone and $PM_{2.5}$ NAAQS, EPA found in 2005 that states had failed to make submissions that address the requirements of section 110(a)(2)(D)(i) related to interstate transport of pollution. *See* 70 FR 21147 (April 25, 2005). Also in 2005, EPA promulgated the CAIR, which was intended to provide states covered by the rule with a mechanism to satisfy their section 110(a)(2)(D)(i)(I) obligations. In the CAIR, EPA concluded that the states in the CAIR region would meet their section 110(a)(2)(D)(i) obligations to address "significant contribution" and " interference with maintenance" requirements by complying with the CAIR requirements. Consequently, states within the CAIR region did not need to submit a separate SIP revision to satisfy the section 110(a)(2)(D)(i) requirements provided they submitted a SIP revision to satisfy CAIR. Most of the CAIR states participated in the CAIR trading programs and submitted SIP revisions that EPA subsequently approved. In 2008, the Court granted several petitions for the review of the CAIR and found, among other things, that EPA had not demonstrated that the CAIR effectuates the statutory mandate of section 110(a)(2)(D)(i)(I). The EPA approvals of the CAIR SIPS preceded the remand of the CAIR by the Court. Therefore, because the D.C. Circuit Court found CAIR and the CAIR FIPs unlawful, EPA's approval of the provisions of a state's SIP submittal as addressing the requirements of the CAIR could not satisfy that state's section 110(a)(2)(D)(i)(I) obligation. In other words, a CAIR SIP submission can no longer be considered an adequate section 110(a)(2)(D)(i)(I) SIP submission. For this reason, EPA's 2005 findings that states had failed to submit SIPs that satisfy section 110(a)(2)(D)(i)(I) [106] remain in force regardless of whether a state covered by the CAIR submitted

[106] The 2005 findings of failure to submit related to states' obligations pursuant to section 110(a)(2)(D)(i). The CAIR, however, addressed only the requirements of 110(a)(2)(D)(i)(I). The remand of CAIR, therefore, had no impact on state SIP submissions or EPA approval of state SIP submissions pursuant to section 110(a)(2)(D)(i)(II).

and/or had an approved SIP stating that compliance with the CAIR satisfied their 110(a)(2)(D)(i) obligations.

The 2005 findings of failure to submit also remain in force for many states not covered by the original CAIR. Some of these states have not yet submitted 110(a)(2)(D)(i)(I) SIPs and thus the findings remain in force. However, several states that were not covered by the CAIR have since 2005 submitted SIP revisions to satisfy the requirements of section 110(a)(2)(D)(i) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS. Some of these SIPs have been approved and some are pending approval.

For the states that have now been identified to be contributing significantly to nonattainment or interfering with maintenance under this proposed rule and whose 110(a)(2)(D)(i)(I) SIPs with respect to the 1997 ozone and $PM_{2.5}$ NAAQS are pending approval, EPA will finalize the FIP included in this proposed rule only if EPA either determines that the SIP submission is incomplete or disapproves the SIP submission. (Alternatively, if a state withdraws its SIP submission, EPA will finalize the FIP.)

For states which are not included in a final FIP under this proposed transport rule and that have not submitted a 110(a)(2)(D)(i)(I) SIP to address the 1997 ozone and $PM_{2.5}$ NAAQS, a SIP submittal is required.

EPA has approved the 110(a)(2)(D)(i) submission from the state of Kansas for the 1997 ozone and $PM_{2.5}$ NAAQS. The updated modeling done for this proposed rule demonstrates that emissions from Kansas significantly contribute to nonattainment or interfere with maintenance of the 1997 8-hour ozone NAAQS in downwind areas. Because Kansas' current SIP does not prohibit these emissions, it is not adequate to satisfy the requirements of 110(a)(2)(D)(i)(I) at this time. For Kansas, under a separate action, EPA plans to propose a finding under CAA 110(k)(5) (known as a SIP Call) that the state's existing SIP is substantially inadequate to meet the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS. That SIP call, if finalized, would also establish a deadline for submission of a new 110(a)(2)(D)(i)(I) SIP which EPA would review for completeness. Therefore, in today's notice EPA is proposing to finalize the FIP for Kansas for ozone only if the state fails to submit a complete and approvable SIP by the deadline established in any final SIP Call.

B. Section 110 (a)(2)(D)(i) SIPs for the 2006 24-Hour $PM_{2.5}$ NAAQS

With respect to the 2006 24-hour $PM_{2.5}$ NAAQS, EPA has issued a separate **Federal Register** notice finding that a number of states failed to make the required 110(a)(2)(D)(i)(I) SIP submissions. None of the SIP submittals in the states that have submitted section 110(a)(2)(D)(i)(I) transport SIPs for the 2006 24-hour $PM_{2.5}$ NAAQS have been acted on yet by EPA. For the states with SIPs that are pending approval, EPA is proposing to finalize the FIP with respect to the 2006 $PM_{2.5}$ NAAQS only if EPA finds the previously submitted SIP incomplete or disapproves the SIP submission. Alternatively, if any of these states withdraws its 2006 24-hour $PM_{2.5}$ SIP submittal, EPA plans to issue a separate notice of finding for such states.

C. Transport Rule SIPs

EPA also notes that, by promulgating these Transport Rule FIPs, EPA would in no way affect the right of states to submit, for review and approval, a SIP that replaces the federal requirements of the FIP with state requirements. In order to replace the FIP in a state, the state's SIP must provide adequate provisions to prohibit NO_X and SO_2 emissions that contribute significantly to nonattainment or interfere with maintenance in another state or states. The Transport Rule FIPs would be in place in each covered state until a state's SIP was submitted and approved by EPA to replace a FIP.

For each upwind state covered by the proposed Transport Rule, EPA proposes state-specific emissions reductions requirements with respect to one or more of three air quality standards—the 1997 annual $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, and the 1997 ozone NAAQS. In CAIR, EPA allowed the states to replace the CAIR FIP with SIPs and provided substantial flexibility. Again EPA wants to offer states substantial flexibility for addressing the Section 110(a)(2)(D)(i)(I) transport issues through a SIP should they choose to do so. The EPA's intent is to provide states with substantial flexibility in implementing these emissions reductions requirements. EPA will allow a state to submit a SIP for the ozone requirements only, for the $PM_{2.5}$ requirements only, or for both the ozone and the $PM_{2.5}$ requirements. The specific quantity of emissions reductions necessary for a state's SIP would be determined based on the state emissions budgets provided in the final transport rule. (*See* Tables IV.E–1 for proposed SO_2 and annual NO_X budgets, and IV.E–2 for proposed ozone season NO_X budgets, in section IV.E).

In the states for which EPA is proposing to require reductions with respect to both the 24-hour $PM_{2.5}$ NAAQS and the annual $PM_{2.5}$ NAAQS, there is no case where the annual standard drives the reduction requirements deeper than would the 24-hour standard alone. Thus, emissions reduction requirements for a SIP to address significant contribution and interference with maintenance with respect to the 24-hour $PM_{2.5}$ NAAQS would be based on the SO_2 and NO_X emissions budgets in Table IV.E–1. For such a state, a SIP that addresses the requirements with respect to the 24-hour $PM_{2.5}$ NAAQS would also by definition address the requirements with respect to the annual $PM_{2.5}$ NAAQS.

EPA is taking comment on all aspects of how a state could replace the Transport Rule FIP with a SIP and on what the SIP approval criteria should be.

VIII. Permitting

A. Title V Permitting

EPA's proposed FIPs would not establish any permitting requirements independent of those under Title V of the CAA and the regulations implementing title V, 40 CFR parts 70 and 71.[107] Title V requires that sources meeting certain criteria have permits meeting the requirements specified in Title V and the Title V regulations. For example, for sources required to have Title V permits, such permits must include, among other things, all "applicable requirements," as defined in the Title V regulations (40 CFR 70.2 and 71.2 (definition of "applicable requirement")).

EPA anticipates that, given the nature of the units covered by the proposed FIPs, most of the sources at which they are located would be subject to Title V permitting requirements. For sources subject to Title V, the requirements applicable to them under the proposed FIPs would be "applicable requirements" under Title V and therefore would need to be included in the Title V permits. For example, requirements under the proposed FIPs concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the assurance provisions, and liability would be "applicable requirements" and necessary to include in the permits.

[107] Part 70 governs approved state Title V programs, and part 71 governs the federal Title V program.

The Title V permits program includes, among other things, provisions for permit applications, permit content, and permit revisions that would address the applicable requirements under the proposed FIPs in a manner that would provide the flexibility necessary to implement a market-based program such as the one that EPA is proposing. For example, the Title V regulations provide that a permit issued under Title V must include, for any "approved * * * emissions trading and other similar programs or processes" applicable to the source, a provision stating that no permit revision is required "for changes that are provided for in the permit." 40 CFR 70.6(a)(8) and 71.6(a)(8). The trading program regulations for the proposed FIPs would include a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. Consistent with the Title V regulations, this provision would also be included in each Title V permit for a covered source. As a result, allowances could be traded (or allocated, held, or deducted) under the FIPs without a revision of the Title V permit of any of the sources involved.

As a further example of flexibility under Title V, the Title V regulations allow the use of the minor permit modification procedures for permit modifications "involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA." 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B). The trading program regulations for the proposed FIPs would include provisions requiring unit owners and operators to submit monitoring system certification applications (or, for alternative monitoring systems, petitions) to EPA establishing the monitoring and reporting approach to be used by the unit. These applications and petitions are subject to EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. As provided in the proposed regulations, EPA would only allow use of approaches that would result in emissions data with an appropriate level of precision, reliability, accessibility, and timeliness. The proposed regulations would also include a provision stating that a description of the general approach that each covered unit is required to use for monitoring and reporting emissions (*i.e.*, an approach using a continuous emissions monitoring system, an excepted monitoring system under appendices D and E to part 75, a low mass emissions excepted monitoring methodology under § 75.19, or an alternative monitoring system under subpart E of part 75) could be added to or changed in a Title V permit using minor permit modification procedures, provided that the requirements applicable to the monitoring and reporting addition or change were already incorporated elsewhere in the permit. As a result, minor permit modification procedures could be used to revise a unit's Title V permit to be consistent with any changes in the monitoring and reporting approach allowed for the unit by EPA through the monitoring system certification or petition process in the proposed trading program regulations. However, if the permit did not already incorporate the monitoring and reporting requirements applicable to the change, the permit would also have to be revised to incorporate these requirements, and this change would not qualify as a minor permit modification pursuant to 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B).

As new applicable requirements under Title V, the requirements for covered units under the final FIPs would be incorporated into covered sources' existing Title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 40 CFR 71.7(f)) or the permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[108] For sources newly subject to title V that would also be covered sources under the proposed FIPs, the initial Title V permit issued pursuant to 40 CFR 70.7(a) would include the final FIP requirements. In order to ensure that covered sources' Title V permit provisions concerning the FIPs would reflect, properly and in a manner consistent from permit to permit, the trading program requirements and flexibilities, EPA intends to issue guidance, after promulgation of the final FIPs, to assist permitting authorities. This guidance would include information on permit issuance and permit modification requirements, as well as a permit content template that would identify the applicable requirements under the trading program and thereby ensure that they would be correctly and comprehensively reflected in each permit in a manner that would reduce the need for frequent permit revisions. Use of a permit content template would also reduce the burden on sources in obtaining, on permitting authorities in issuing, and on EPA in reviewing, permits or permit revisions.

B. New Source Review

EPA recognizes that pollution control projects, including pollution control projects constructed to comply with the proposed rule, have the potential to trigger new source review (NSR) permitting.

On December 20, 2005, the EPA agreed to reconsider one specific aspect of the CAIR. In that notice, EPA granted reconsideration and sought comment on the potential impact of a judicial opinion, *New York* v. *EPA*, 413 F.3d 3 (D.C. Cir. 2005). This decision vacated the pollution control project exclusion in EPA's NSR regulations. (The exclusion allowed for certain environmentally beneficial pollution control projects to be excluded from certain NSR requirements.) For this reconsideration, EPA conducted an analysis which showed that the court decision did not impact the CAIR analyses. The EPA believes this analysis, which remains current and relevant for all pollutants except for greenhouse gas (GHG), shows that New Source Review (NSR) requirements would not significantly impact the construction of controls that are installed to comply with the proposed transport rule. Details of this analysis can be found in a Technical Support document which is available on EPA's Web site at: *http://epa.gov/cair/pdfs/0053–2263.pdf*.

Because GHG was not considered by EPA to be a "pollutant", let alone a "regulated pollutant," at the time of CAIR, GHG was not addressed in the previous analysis. GHG requirements related to the component of new source review concerning the Prevention of Significant Deterioration ("PSD") program have recently been addressed in EPA's "Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs," 75 FR 17004 (April 2, 2010), and "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule," 75 FR (June 3, 2010) ("Tailoring Rule"). Generally, as discussed in those actions, once the PSD requirements for GHG take effect on January 2, 2011, major stationary sources will be required to address GHG emissions as part of the PSD program if these sources emit GHG in amounts that equal or

[108] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to a covered source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(i) and 71.7(f)(1)(i).

exceed the thresholds in the Tailoring Rule. Once the PSD requirements take effect, major sources that undergo a modification, including the addition of pollution control equipment, will trigger PSD requirements for their emissions of GHG if such emissions increase by at least 75,000 tons per year of CO_2 equivalent. EPA believes it is very unlikely that pollution control projects would cause GHG increases that would exceed the 75,000 tons per year threshold.

Consistent with EPA's previous analysis and EPA's conclusions for GHG, EPA does not believe that there are significant impacts from NSR for any pollution control projects resulting from the proposed rule such as low-NO_X burners, SO_2 scrubbers, or SCR. EPA requests comment on this issue.

IX. What benefits are projected for the proposed rule?

In this section, we present the results of EPA's analysis of the benefits of the emissions reductions in this proposal on $PM_{2.5}$ and ozone air quality, public health, welfare, and the environment. These improvements were determined based upon air quality modeling of the 2014 base case and the "State Budgets/ Limited Trading" remedy proposed in this rule, as described in section V, above.

Implementation of this rule will very substantially lower the extent of nonattainment and maintenance problems for the annual and 24-hour $PM_{2.5}$ NAAQS and 8-hour ozone NAAQS in the eastern U.S. (*see* section IX.A, below). The improvements in air quality will annually prevent thousands of premature deaths and other serious health effects (*see* section IX.B, below). We estimate the total monetized annual benefits to be approximately $120 billion to $290 billion or $110 billion to $270 billion in 2014 (at a 3 percent and a 7 percent discount rate, respectively) for the proposed "State Budgets/Limited Trading" remedy. There will be significant benefits that are not quantified. Notably, in 2012 the benefits are actually larger since greater emissions reductions are occurring from the baseline in that timeframe, as indicated in Table V.E–2, above. Because the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration-response function for premature mortality, we examined alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts. Higher and lower co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates above.[109] All monetized estimates are stated in 2006 dollars. Also note that the analytic baseline presents a unique situation. EPA has been directed to replace the CAIR; yet the CAIR remains in place and has led to significant emissions reductions in many states.

A key step in the process of developing a 110(a)(2)(D)(i)(I) rule involves analyzing existing (base case) emissions to determine which states significantly contribute to downwind nonattainment and maintenance areas. EPA cannot prejudge at this stage which states will be affected by the rule. For example, a state affected by CAIR may not be affected by the new rule and after the new rule goes into effect, the CAIR requirements will no longer apply. For a state covered by CAIR but not covered by the new rule, the CAIR requirements would not be replaced with new requirements, and therefore an increase in emissions relative to present levels could occur in that state. More fundamentally, the court has made clear that, due to legal flaws, the CAIR rule cannot remain in place and must be replaced. If EPA's base case analysis were to ignore this fact and assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. For these reasons, EPA cannot assume in its base case analysis, that the reductions required by CAIR will continue to be achieved.

Following this logic, the 2012 base case shows emissions higher than current levels in some states. Because EPA has been directed to replace CAIR, EPA believes that for many states, the absence of the CAIR NO_X program will lead to the status quo of the NO_X Budget Program, which limits ozone-season NO_X emissions and ensures the operation of NO_X controls in those states. Also, without the CAIR SO_2 program, emission requirements in many areas would revert to the comparatively less stringent requirements of the Title IV Acid Rain program. As a result, SO_2 emissions in many states would increase markedly in the 2012 base case relative to the present. Efforts to comply with ARP rules at the least-cost would occur in many cases without the operation of existing scrubbers through use of readily available, inexpensive Title IV allowances. Notably, all known controls that are required under state laws, NSPS, consent decrees, and other enforceable binding commitments through 2014 are accounted for in the base case. It is against this backdrop that the Transport Rule is analyzed and that significant contribution to nonattainment and interference with maintenance must be addressed.

A. The Impacts on $PM_{2.5}$ and Ozone of the Proposed SO_2 and NO_X Strategy

The air quality modeling platform described in section IV.C. was used by EPA to model the impacts of the proposed SO_2 and NO_X emissions reductions on annual average $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone concentrations. In brief, we ran the CAMx model for the meteorological conditions in the year of 2005 for the eastern U.S. modeling domain.[110] Modeling was performed for the 2014 base case and the 2014 "State Budgets/ Limited Trading" scenario to assess the expected effects of the proposed regional strategy on projected $PM_{2.5}$ and ozone design value concentrations and nonattainment and maintenance. The procedures used to project future design values and nonattainment and maintenance are described in section IV.C. The aggregate emissions in 2012 and 2014 for SO_2 and NO_X are provided in Table V.E–2 in section V.E. The emissions by state are provided in Tables V.E–5 through V.E–7 in section V.E, and also in the Air Quality Modeling TSD.

The projected 2014 concentrations of annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone at each monitoring site in the East for which projections were made are provided in the AQMTSD. The number of nonattainment and/or maintenance sites in the East for the 2012 base case, 2014 base case, and 2014 remedy for annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone are provided in Table IX–1.[111] The average and peak reductions in annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone predicted at 2012 nonattainment and/or maintenance sites due to the emissions reductions

[109] Roman *et al.,* 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

[110] As described in the AQMTSD, the eastern U.S. was modeled at a horizontal resolution of 12 x 12 km. The remainder of the U.S. was modeled at a resolution of 36 x 36 km.

[111] To provide a point of reference, Table IX–1 also includes the number of nonattainment and/ maintenance sites based on ambient design values for the period 2003 through 2007.

between 2012 and the 2014 remedy are provided in Table IX–2.

TABLE IX–1—PROJECTED REDUCTION IN NONATTAINMENT AND/OR MAINTENANCE PROBLEMS FOR $PM_{2.5}$ AND OZONE IN THE EASTERN U.S.

	Ambient (2003–2007)	2012 base case	2014 base case	2014 proposed remedy	Percent reduction: 2012 base case vs. 2014 remedy (percent)	Percent reduction: 2014 base case vs. 2014 remedy (percent)
Annual $PM_{2.5}$ Nonattainment Sites [112]	102	32	15	1	97	93
Annual $PM_{2.5}$ Maintenance-Only Sites	21	16	7	1	94	86
Daily $PM_{2.5}$ Nonattainment Sites	151	92	54	17	82	69
Daily $PM_{2.5}$ Maintenance-Only Sites	48	38	28	11	71	61
Ozone Nonattainment Sites	103	11	7	7	36	0
Ozone Maintenance-Only Sites	67	16	6	5	69	17

TABLE IX–2—AVERAGE AND PEAK REDUCTION IN ANNUAL $PM_{2.5}$, DAILY $PM_{2.5}$, AND OZONE FOR SITES THAT ARE PROJECTED TO HAVE NONATTAINMENT AND/OR MAINTENANCE PROBLEMS IN THE 2012 BASE CASE

	Average reduction: 2012 base case to 2014 remedy	Peak reduction: 2012 base case to 2014 remedy
Annual $PM_{2.5}$ Nonattainment Sites	2.8 $\mu g/m^3$	3.9 $\mu g/m^3$
Annual $PM_{2.5}$ Maintenance-Only Sites	2.6 $\mu g/m^3$	4.2 $\mu g/m^3$
Daily $PM_{2.5}$ Nonattainment Sites	5.8 $\mu g/m^3$	15.3 $\mu g/m^3$
Daily $PM_{2.5}$ Maintenance-Only Sites	5.1 $\mu g/m^3$	13.5 $\mu g/m^3$
Ozone Nonattainment Sites	1.9 ppb	3.9 ppb
Ozone Maintenance-Only Sites	2.3 ppb	4.2 ppb

The information in Table IX–1 shows that there will be significant reductions in the extent of nonattainment and maintenance problems for annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone between 2012 and 2014 as a result of the emissions budgets in this proposal coupled with emissions reductions during this time period from other existing control programs. Specifically, the results of the air quality modeling indicate that all but 1 site is projected to be in attainment and only 1 site is projected to have a maintenance problem for annual $PM_{2.5}$ in 2014 with the emissions reductions expected from this proposal. As indicated in Table IX–2, the average reduction in annual $PM_{2.5}$ across the 32 2012 nonattainment sites is 1.9 $\mu g/m^3$ and the peak reduction at an individual nonattainment site is 3.2 $\mu g/m^3$. Comparable reductions are projected at annual $PM_{2.5}$ maintenance-only sites.

For 24-hour $PM_{2.5}$, we project that the number of nonattainment sites will be reduced by 82 percent and the number of maintenance-only sites by 71 percent in 2014 compared to the 2012 base case. The average reduction in 24-hour $PM_{2.5}$ across the 92 2012 nonattainment sites is 5.8 $\mu g/m^3$ and the peak reduction at an individual nonattainment site is 15.3 $\mu g/m^3$. Comparable reductions are projected at 24-hour $PM_{2.5}$ maintenance-only sites.

The emissions reductions in this proposal will result in considerable progress toward attainment and maintenance at the 28 sites that remain as nonattainment and/or maintenance for the 24-hour $PM_{2.5}$ standard. On average for these 28 sites, the predicted amount of $PM_{2.5}$ reduction in 2014 is more than half of what is needed for these sites to attain and/or maintain the 24-hour standard.

Thus, the SO_2 and NO_X emissions reductions which will result from today's proposal will greatly reduce the extent of $PM_{2.5}$ nonattainment and maintenance problems by 2014 and beyond. As described previously, these emissions reductions are expected to substantially reduce the number of $PM_{2.5}$ nonattainment and/or maintenance sites in the East and make attainment easier for those counties that remain nonattainment by substantially lowering $PM_{2.5}$ concentrations in residual nonattainment sites. The emissions reductions will also help those locations that may have maintenance problems.

Based on the 2012 base air quality modeling for ozone, 27 sites in the East are projected to be nonattainment or have problems maintaining the 1997 ozone standard. The initial phase of summer NO_X reductions in today's proposal are projected to lower 8-hour ozone concentration by 2.8 ppb, on average by 2014, at monitoring sites projected to be nonattainment and/or have maintenance problems in the 2012 base case. We expect that the number of nonattainment sites will be reduced by 36 percent and the number of maintenance-only sites by 69 percent in 2014 compared to the 2012 base case. For the 12 sites expected to have residual nonattainment/maintenance problems in 2014, the predicted ozone reductions provide nearly 10 percent of the amount needed for these sites to attain and/or maintain the ozone standard. Thus, our modeling indicates that by 2014 the initial phase of summer NO_X emissions reductions in this proposal will lower ozone concentrations in the East and help bring areas closer to attainment for the 8-hour ozone NAAQS.

[112] "Nonattainment" is used to denote sites that are projected to have both nonattainment and maintenance problems.

B. Human Health Benefit Analysis

To estimate the human health benefits of the proposed Transport Rule, we used the BenMAP model to quantify the changes in $PM_{2.5}$ and ozone-related health impacts and monetized benefits based on changes in air quality. We provide such estimates for the proposed remedy option. Notably, EPA expects that in 2014 the other two alternatives that the Agency considered have the same general level of benefits that will result from their implementation. The results of the analysis for the alternate SO_2 reduction scenarios are found in the RIA. For context, it is important to note that the magnitude of the $PM_{2.5}$ benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this proposed rule we cite two key empirical studies, one based on the American Cancer Society cohort study [113] and the other based on the extended Six Cities cohort study.[114]

Table IX–3 presents the primary estimates of reduced incidence of $PM_{2.5}$ and ozone-related health effects in 2014 for the proposed and alternative remedies. In 2014, we estimate that PM-related annual benefits of the proposed remedy include approximately 14,000 to 36,000 fewer premature mortalities, 9,200 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 11,000 fewer hospitalizations (for respiratory and cardiovascular disease combined), 10 million fewer days of restricted activity due to respiratory illness and approximately 1.8 million fewer work-loss days. We also estimate substantial health improvements for children from fewer cases of upper and lower respiratory illness, acute bronchitis, and asthma attacks. As mentioned earlier, the reduced incidences of various effects would be greater in 2012 due to the larger emissions reductions that occur from the baseline. The lower reductions in emissions in 2014 result from further SO_2 controls in the proposed remedy because the baseline has much greater controls resulting from state actions and consent decrees.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the eastern U.S.). Based upon modeling for 2014, annual ozone related health benefits are expected to include between 50 and 230 fewer premature mortalities, 690 fewer hospital admissions for respiratory illnesses, 230 fewer emergency room admissions for asthma, 300,000 fewer days with restricted activity levels, and 110,000 fewer days where children are absent from school due to illnesses. When adding the PM and ozone-related mortalities together, we find that the proposed Transport Rule will yield between 14,000 and 36,000 fewer premature mortalities. The following references are used in providing our estimates of ozone health-related benefits:

Bell, M.L., *et al.* 2004. Ozone and short-term mortality in 95 U.S. urban communities, 1987–2000. Journal of the American Medical Association. 292 (19): p. 2372–8.

Laden, F., J. Schwartz, F.E. Speizer, and D.W. Dockery. 2006. Reduction in Fine Particulate Air Pollution and Mortality. American Journal of Respiratory and Critical Care Medicine 173:667–672. Estimating the Public Health Benefits of Proposed Air Pollution Regulations. Washington, DC: The National Academies Press.

Levy JI, Baxter LK, Schwartz J. 2009. Uncertainty and variability in health-related damages from coal-fired power plants in the United States. Risk Anal. doi: 10.1111/j.1539–6924.2009.01227.x [Online 9 Apr 2009]

Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution. Journal of the American Medical Association 287:1132–1141.

TABLE IX–3—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS [A]

Health effect	Proposed remedy
PM-Related endpoints	
Premature Mortality	
Pope *et al.* (2002) (age >30)	14,000 (4,000–25,000)
Laden *et al.* (2006) (age >25)	36,000 (17,000–56,000)
Infant (< 1 year)	59 (−66–180)
Chronic Bronchitis	9,200 (320–18,000)
Non-fatal heart attacks (age > 18)	22,000 (5,800–39,000)
Hospital admissions—respiratory (all ages)	3,500 (1,400–5,500)
Hospital admissions—cardiovascular (age > 18)	7,500 (5,200–8,900)
Emergency room visits for asthma (age < 18)	14,000 (7,200–21,000)
Acute bronchitis (age 8–12)	21,000 (−4,800–46,000)
Lower respiratory symptoms (age 7–14)	250,000 (98,000–400,000)
Upper respiratory symptoms (asthmatics age 9–18)	190,000 (36,000–350,000)
Asthma exacerbation (asthmatics 6–18)	240,000 (8,300–800,000)
Lost work days (ages 18–65)	1,800,000 (1,500,000–2,000,000)
Minor restricted-activity days (ages 18–65)	10,000,000 (8,600,000–12,000,000)
Ozone-related endpoints	
Premature mortality	
Bell *et al.* (2004) (all ages)	50 (17–84)
Levy *et al.* (2005) (all ages)	230 (160–300)
Hospital admissions—respiratory causes (ages > 65)	390 (−18–740)
Hospital admissions—respiratory causes (ages < 2)	300 (130–460)
Emergency room visits for asthma (all ages)	230 (−30–730)
Minor restricted-activity days (ages 18–65)	300,000 (130,000–480,000)

[113] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association.* 287:1132–1141.

[114] Laden *et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173:667–672.

TABLE IX–3—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS [A]—Continued

Health effect	Proposed remedy
School absence days	110,000 (38,000–160,000)

[A] Values rounded to two significant figures. Benefits from reducing other criteria pollutants and hazardous air pollutants and ecosystem effects are not included here.

C. Quantified and Monetized Visibility Benefits

Only a subset of the expected visibility benefits—those for Class I areas—are included in the monetary benefits estimates we project for this rule. We anticipate improvement in visibility in residential areas where people live, work and recreate within the Transport Rule region for which we are currently unable to monetize benefits. For the Class I areas we estimate annual benefits of $3.4 billion beginning in 2014 for visibility improvements. Methodological limitations prevented us from quantifying the visibility benefits of the alternate remedies. The value of visibility benefits in areas where we were unable to monetize benefits could also be substantial.

D. Benefits of Reducing GHG Emissions

When fully implemented in 2014, the proposed Transport Rule would reduce emissions of CO_2 from electrical generating units by about 15 million metric tons annually. Using a "social cost of carbon" (SCC) estimate that accounts for the marginal dollar value (*i.e.*, cost) of climate-related damages resulting from CO_2 emissions, previous analyses including the RIA for the Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Efficiency Standards have found the total benefit of CO_2 reductions is substantial. The monetary value of these avoided damages also grows over time. Readers interested in learning more about the calculation of the SCC metric should refer to the SCC TSD, *Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* [Docket No. EPA–HQ–OAR–2009–0472].

E. Total Monetized Benefits

Table IX–4 presents the estimated monetary value of reductions in the incidence of health and welfare effects. These estimates account for increases in the value of risk reduction over time. As the table indicates, total benefits are driven primarily by the reduction in premature fatalities each year, which account for over 90 percent of total benefits.

Table IX–5 presents the total monetized net benefits for 2014. A listing of the benefit categories that could not be quantified or monetized in our benefit estimates are provided in Table IX–6.

TABLE IX–4—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS

(Billions Of 2006$) [A]

Health effect	Pollutant	Proposed remedy
Premature mortality (Pope *et al.* 2002 PM mortality and Bell *et al.* 2004 ozone mortality estimates)		
3% discount rate	$PM_{2.5}$ & O_3	$110 ($8.8–$340)
7% discount rate	$PM_{2.5}$ & O_3	$100 ($7.9–$300)
Premature mortality (Laden *et al.* 2006 PM mortality and Levy *et al.* 2005 ozone mortality estimates)		
3% discount rate	$PM_{2.5}$ & O_3	$280 ($25–$820)
7% discount rate	$PM_{2.5}$ & O_3	$260 ($22–$310)
Chronic bronchitis	$PM_{2.5}$	$4.3 $0.2–$20)
Non-fatal heart attacks.		
3% discount rate	$PM_{2.5}$	$2.5 ($0.4–$6)
7% discount rate	$PM_{2.5}$	$2.4 ($0.4–$5.9)
Hospital admissions—respiratory	$PM_{2.5}$ & O_3	$0.06 ($0.03–$0.1)
Hospital admissions—cardiovascular	$PM_{2.5}$	$0.2 ($0.1–$0.3)
Emergency room visits for asthma	$PM_{2.5}$ & O_3	$0.005 ($0.002–$0.008)
Acute bronchitis	$PM_{2.5}$	$0.009 (−$0.0004–$0.03)
Lower respiratory symptoms	$PM_{2.5}$	$0.005 ($0.002–$0.009)
Upper respiratory symptoms	$PM_{2.5}$	$0.006 ($0.001–$0.014)
Asthma exacerbation	$PM_{2.5}$	$0.012 ($0.001–$0.046)
Lost work days	$PM_{2.5}$	$0.2 ($0.19–$0.24)
School loss days		$0.01 ($0.004–$0.013)
Minor restricted-activity days	$PM_{2.5}$ & O_3	$0.64 ($0.34–$0.97)
Recreational visibility, Class I areas	$PM_{2.5}$	$3.6
Total benefits based on Pope *et al.* 2002 PM mortality and Bell *et al.* 2004 ozone mortality estimates		
3% discount rate	$PM_{2.5}$ & O_3	$120 ($10–$360)
7% discount rate	$PM_{2.5}$ & O_3	$110 ($9–$330)
Total benefits based on Laden *et al.* 2006 PM mortality and Levy *et al.* 2005 ozone mortality estimates		
3% discount rate	$PM_{2.5}$ & O_3	$290 ($26–$840)
7% discount rate	$PM_{2.5}$ & O_3	$270 ($24–$760)

[A] Estimates rounded to two significant figures.

E. How do the benefits compare to the costs of this proposed rule?

The estimated annual private costs to implement the emission reduction requirements of the proposed rule for the Transport Rule region are $3.7 billion in 2012 and $2.8 billion in 2014 (2006$) for the proposed remedy option, $4.2 billion in 2012 and $2.7 billion in 2014 for the State Budgets/Intrastate Trading remedy option, and $4.3 billion in 2012 and $3.4 billion in 2014 for the direct control remedy option. These costs are the annual incremental electric generation production costs that are expected to occur with the Transport Rule. The EPA uses these costs as compliance cost estimates in developing cost-effectiveness estimates.

In estimating the net benefits of regulation, the appropriate cost measure is "social costs." Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule (thus reflecting the proposed remedy option) are estimated to be approximately $2.0 billion in 2014 assuming a 3 percent discount rate. These costs become $2.2 billion in 2014, if one assumes a 7 percent discount rate. Thus, the net benefit (social benefits minus social costs) as will be shown in Table IX–5 for the proposed remedy option is approximately $120 to 292 billion or $109 to 264 billion (3 percent and 7 percent discount rates) in 2014. Implementation of the rule is expected to provide society with a substantial net gain in social welfare based on economic efficiency criteria.

The annualized regional cost of the proposed rule, as quantified here, is EPA's best assessment of the cost of implementing the proposed option. These costs are generated from rigorous economic modeling of changes in the power sector expected from the proposed rule. This type of analysis using IPM has undergone peer review and been upheld in federal courts. The direct cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. The EPA believes that these costs reflect, as closely as possible, the additional costs of the proposed option to industry. The relatively small cost associated with monitoring emissions, reporting, and recordkeeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to less than $28 million (see section XII.B., Paperwork Reduction Act). However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to this rule, such as the costs associated with the retirement of smaller or less efficient EGUs, employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy, and certain relatively small permitting costs associated with Title V that new program entrants face.

An optimization model was employed that assumes cost minimization. Costs may be understated if the regulated community chooses not to minimize its compliance costs in the same manner to comply with the rules. Although EPA has not quantified these costs, the Agency believes that they are small compared to the quantified costs of the program on the power sector. However, EPA's experience and results of independent evaluation suggests that costs are likely to be lower by some degree (*see* RIA for details). The annualized cost estimates presented are the best and most accurate based upon available information. In a separate analysis, EPA estimates the indirect costs and impacts of higher electricity prices on the entire economy. These impacts are summarized in section X of this preamble and in the RIA for this proposed rule.

TABLE IX–5—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE TRANSPORT RULE IN 2014

[Billions of 2006 dollars]

Description	Proposed remedy
Social costs:	
3 percent discount rate	$2.0.
7 percent discount rate	$2.2.
Social benefits:	
3 percent discount rate	$122 to 294 + B.
7 percent discount rate	$111 to 266 + B.
Health-related benefits:	
3 percent discount rate	$118 to 290.
7 percent discount rate	$107 to 262.
Visibility benefits:	
3 percent discount rate	$3.6.
7 percent discount rate	$3.6.
Annual net benefits (benefits-costs)	
3 percent discount rate	$120 to 292.
7 percent discount rate	$109 to 264.

[a] All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for 2014. Estimates relate to the complete Transport Rule program.

[b] Note that costs are the annual total costs of reducing pollutants including NO_X and SO_2 in the Transport Rule region.

[c] As this table indicates, total benefits are driven primarily by $PM_{2.5}$-related health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits 2014. Benefits in this table are nationwide (with the exception of visibility) and are associated with NO_X and SO_2 reductions for the EGU source category. Ozone benefits represent benefits in the eastern United States. Visibility benefits represent benefits in Class I areas in the southeastern United States.

[d] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table IX–6. We represent the value of unquantified benefits and disbenefits with a "B."

[e] Valuation assumes discounting over the SAB-recommended 20 year segmented lag structure described in chapter 4 of the Regulatory Impact Analysis for the Clean Air Interstate Rule (March 2005). Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000 and OMB, 2003).174

[f] Net benefits are rounded to the nearest $1 billion. Columnar totals may not sum due to rounding.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects. Gaps in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While uncertainties in the underlying scientific and economics literatures (that may result in overestimation or underestimation of benefits) are discussed in detail in the economic analyses and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this rule include the following:

- EPA's inability to quantify potentially significant benefit categories;
- Uncertainties in population growth and baseline incidence rates;
- Uncertainties in projection of emissions inventories and air quality into the future;
- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations including the shape of the C–R function, the size of the effect estimates, and the relative toxicity of the many components of the PM mixture;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the rulemaking in future years under a set of reasonable assumptions. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[115] The benefits estimates generated for this rule are subject to a number of assumptions and uncertainties, which are discussed throughout the RIA document.

As Table IX–4 indicates, total benefits are driven primarily by the reduction in premature mortalities each year. Some key assumptions underlying the primary estimate for the premature mortality category include the following:

(1) EPA assumes inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Plausible biological mechanisms for this effect have been hypothesized for the endpoints included in the primary analysis and the weight of the available epidemiological evidence supports an assumption of causality.

(2) EPA assumes all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because the proportion of certain components in the PM mixture produced via precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

(3) We assume that the health impact function for fine particles is linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both regions that are in attainment with fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.

The EPA recognizes the difficulties, assumptions, and inherent uncertainties in the overall enterprise. The analyses upon which the Transport Rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

There are a number of health and environmental effects that we were unable to quantify or monetize. A complete benefit-cost analysis of the Transport Rule requires consideration of all benefits and costs expected to result from the rule, not just those benefits and costs which could be expressed here in dollar terms. A listing of the benefit categories that were not quantified or monetized in our estimate are provided in Table IX–6.

F. What are the unquantified and unmonetized benefits of the Transport Rule emissions reductions?

Important benefits beyond the human health and welfare benefits resulting from reductions in ambient levels of $PM_{2.5}$ and ozone in the eastern United States are expected to occur from this rule. These other benefits occur both directly from NO_X and SO_2 emissions reductions. These benefits are listed in Table IX–6. Some of the more important examples include: Reductions in NO_X and SO_2 emissions required by the Transport Rule will reduce acidification and, in the case of NO_X, eutrophication of water bodies. Reduced nitrate contamination of drinking water is another possible benefit of the rule. This proposed rule will also reduce acid and particulate deposition that causes damages to cultural monuments, as well as, soiling and other materials damage. To illustrate the important nature of benefit categories we are currently unable to monetize, we discuss four categories of public welfare and environmental impacts related to reductions in emissions required by the Transport Rule: Reduced acid deposition, reduced eutrophication of estuaries, and reduced vegetation impairment from ozone.

1. What are the benefits of reduced deposition of sulfur and nitrogen to aquatic, forest, and coastal ecosystems?

Atmospheric deposition of sulfur and nitrogen, often referred to as acid rain, occurs when emissions of SO_2 and NO_X react in the atmosphere (with water, oxygen, and oxidants) to form various acidic compounds. These acidic compounds fall to earth in either a wet form (rain, snow, and fog) or a dry form (gases and particles). Prevailing winds can transport acidic compounds hundreds of miles, across state borders. Together these emissions are deposited onto terrestrial and aquatic ecosystems across the U.S., contributing to the problems of acidification, nutrient enrichment, and methylmercury production. In addition, NO_X is a precursor to ozone, which can impair vegetation.

a. Acid Deposition and Acidification of Lakes and Streams

The extent of adverse effects of acid deposition on freshwater and forest ecosystems depends largely upon the ecosystem's ability to neutralize the acid. The neutralizing ability [key indicator is termed Acid Neutralizing Capacity (ANC)] depends largely on the watershed's physical characteristics, such as geology, soils, and size. Acidic conditions occur more frequently during rainfall and snowmelt that cause high flows of water and less commonly during low-flow conditions, except where chronic acidity conditions are severe. Biological effects are primarily attributable to a combination of low pH and high inorganic aluminum

[115] In this analysis, we adjust the VSL to account for a different currency year (2006$) and to account for income growth to 2014. After applying these adjustments to the $6.3 million value, the VSL is $8.5 million.

concentrations. Biological effects of episodes include reduced fish condition factor, changes in species composition and declines in aquatic species richness across multiple taxa, ecosystems and regions, as well as fish mortality. Waters that are sensitive to acidification tend to be located in small watersheds that have few alkaline minerals and shallow soils. Conversely, watersheds that contain alkaline minerals, such as limestone, tend to have waters with a high ANC. Areas especially sensitive to acidification include portions of the Northeast (particularly, the Adirondack and Catskill Mountains, portions of New England, and streams in the mid-Appalachian highlands) and southeastern streams. This regulatory action will decrease acid deposition in the transport region and is likely to have positive effects on the health and productivity of aquatic ecosystems in the region.

b. Acid Deposition and Forest Ecosystem Impacts

Acidifying deposition has altered major biogeochemical processes in the U.S. by increasing the nitrogen and sulfur content of soils, accelerating nitrate and sulfate leaching from soil to drainage waters, depleting base cations (especially calcium and magnesium) from soils, and increasing the mobility of aluminum. Inorganic aluminum is toxic to some tree roots. Plants affected by high levels of aluminum from the soil often have reduced root growth, which restricts the ability of the plant to take up water and nutrients, especially calcium (U.S. EPA, 2008f). These direct effects can, in turn, influence the response of these plants to climatic stresses such as droughts and cold temperatures. They can also influence the sensitivity of plants to other stresses, including insect pests and disease (Joslin *et al.*, 1992), leading to increased mortality of canopy trees.

Both coniferous and deciduous forests throughout the eastern U.S. are experiencing gradual losses of base cation nutrients from the soil due to accelerated leaching for acidifying deposition. This change in nutrient availability may reduce the quality of forest nutrition over the long term. Evidence suggests that red spruce and sugar maple in some areas in the eastern U.S. have experienced declining health because of this deposition. For red spruce (*Picea rubens*), dieback or decline has been observed across high elevation landscapes of the northeastern U.S., and to a lesser extent, the southeastern U.S., and acidifying deposition has been implicated as a causal factor (DeHayes *et al.*, 1999).

This regulatory action will decrease acid deposition in the transport region and is likely to have positive effects on the health and productivity of forest systems in the region.

c. Coastal Ecosystems

Since 1990, a large amount of research has been conducted on the impact of nitrogen deposition to coastal waters. Nitrogen is often the limiting nutrient in coastal ecosystems. Increasing the levels of nitrogen in coastal waters can cause significant changes to those ecosystems. In recent decades, human activities have accelerated nitrogen nutrient inputs, causing excessive growth of algae and leading to degraded water quality and associated impairments of estuarine and coastal resources.

Atmospheric deposition of nitrogen is a significant source of nitrogen to many estuaries. The amount of nitrogen entering estuaries due to atmospheric deposition varies widely, depending on the size and location of the estuarine watershed and other sources of nitrogen in the watershed. A recent assessment of 141 estuaries nationwide by the National Oceanic and Atmospheric Administration (NOAA) concluded that 19 estuaries (13 percent) suffered from moderately high or high levels of eutrophication due to excessive inputs of both N and phosphorus, and a majority of these estuaries are located in the coastal area from North Carolina to Massachusetts (NOAA, 2007). For estuaries in the Mid-Atlantic region, the contribution of atmospheric distribution to total N loads is estimated to range between 10 percent and 58 percent (Valigura *et al.*, 2001).

Eutrophication in estuaries is associated with a range of adverse ecological effects. The conceptual framework developed by NOAA emphasizes four main types of eutrophication effects—low dissolved oxygen (DO), harmful algal blooms (HABs), loss of submerged aquatic vegetation (SAV), and low water clarity. Low DO disrupts aquatic habitats, causing stress to fish and shellfish, which, in the short-term, can lead to episodic fish kills and, in the long-term, can damage overall growth in fish and shellfish populations. Low DO also degrades the aesthetic qualities of surface water. In addition to often being toxic to fish and shellfish, and leading to fish kills and aesthetic impairments of estuaries, HABs can, in some instances, also be harmful to human health. SAV provides critical habitat for many aquatic species in estuaries and, in some instances, can also protect shorelines by reducing wave strength; therefore, declines in SAV due to nutrient enrichment are an important source of concern. Low water clarity is the result of accumulations of both algae and sediments in estuarine waters. In addition to contributing to declines in SAV, high levels of turbidity also degrade the aesthetic qualities of the estuarine environment.

Estuaries in the eastern United States are an important source of food production, in particular fish and shellfish production. The estuaries are capable of supporting large stocks of resident commercial species, and they serve as the breeding grounds and interim habitat for several migratory species.

This rule is anticipated to reduce nitrogen deposition in the Transport Rule region. Thus, reductions in the levels of nitrogen deposition will have a positive impact upon current eutrophic conditions in estuaries and coastal areas in the region.

d. Mercury Methylation and Deposition

Mercury is a highly neurotoxic contaminant that enters the food web as a methylated compound, methylmercury (U.S. EPA, 2008d). The contaminant is concentrated in higher trophic levels, including fish eaten by humans. Experimental evidence has established that only inconsequential amounts of methylmercury can be produced in the absence of sulfate. Current evidence indicates that in watersheds where mercury is present, increased SO_X deposition very likely results in methylmercury accumulation in fish (Drevnick *et al.*, 2007; Munthe *et al.,* 2007). The SO_2 ISA (U.S. EPA, 2008) concluded that evidence is sufficient to infer a casual relationship between sulfur deposition and increased mercury methylation in wetlands and aquatic environments.

2. Ozone Vegetation Effects

Ozone causes discernible injury to a wide array of vegetation (U.S. EPA, 2006; Fox and Mickler, 1996). In terms of forest productivity and ecosystem diversity, ozone may be the pollutant with the greatest potential for regional-scale forest impacts (U.S. EPA, 2006). Studies have demonstrated repeatedly that ozone concentrations commonly observed in polluted areas can have substantial impacts on plant function (De Steiguer *et al.*, 1990; Pye, 1988).

Assessing the impact of ground-level ozone on forests in the eastern United States involves understanding the risks to sensitive tree species from ambient ozone concentrations and accounting for the prevalence of those species within the forest. As a way to quantify the risks to particular plants from ground-level

ozone, scientists have developed ozone-exposure/tree-response functions by exposing tree seedlings to different ozone levels and measuring reductions in growth as "biomass loss." Typically, seedlings are used because they are easy to manipulate and measure their growth loss from ozone pollution. The mechanisms of susceptibility to ozone within the leaves of seedlings and mature trees are identical, and the decreases predicted using the seedlings should be related to the decrease in overall plant fitness for mature trees, but the magnitude of the effect may be higher or lower depending on the tree species (Chappelka and Samuelson, 1998). In areas where certain ozone-sensitive species dominate the forest community, the biomass loss from ozone can be significant. Significant biomass loss can be defined as a more than 2 percent annual biomass loss, which would cause long-term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health (Heck, 1997).

Urban ornamentals are an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels. Because ozone causes visible foliar injury, the aesthetic value of ornamentals (such as petunia, geranium, and poinsettia) in urban landscapes would be reduced (U.S. EPA, 2007). Sensitive ornamental species would require more frequent replacement and/or increased maintenance (fertilizer or pesticide application) to maintain the desired appearance because of exposure to ambient ozone (U.S. EPA, 2007). In addition, many businesses rely on healthy-looking vegetation for their livelihoods (e.g., horticulturalists, landscapers, Christmas tree growers, farmers of leafy crops, etc.) and a variety of ornamental species have been listed as sensitive to ozone (Abt Associates, 1995).

3. Other Health or Welfare Disbenefits of the Transport Rule That Have Not Been Quantified

In contrast to the additional benefits of the proposed rule discussed above, it is also possible that this rule will result in disbenefits in some areas of the region. Current levels of nitrogen deposition in these areas may provide passive fertilization for forest and terrestrial ecosystems where nutrients are a limiting factor and for some croplands. The effects of ozone and PM on radiative transfer in the atmosphere can also lead to effects of uncertain magnitude and direction on the penetration of ultraviolet light and climate. Ground level ozone makes up a small percentage of total atmospheric ozone (including the stratospheric layer) that attenuates penetration of ultraviolet-b (UVb) radiation to the ground. The EPA's past evaluation of the information indicates that potential disbenefits would be small, variable, and with too many uncertainties to attempt quantification of relatively small changes in average ozone levels over the course of a year (EPA, 2005a). The EPA's most recent provisional assessment of the currently available information indicates that potential but unquantifiable benefits may also arise from ozone-related attenuation of UVb radiation (EPA, 2005b). Sulfate and nitrate particles also scatter UVb, which can decrease exposure of horizontal surfaces to UVb, but increase exposure of vertical surfaces. In this case as well, both the magnitude and direction of the effect of reductions in sulfate and nitrate particles are too uncertain to quantify (EPA, 2004). Ozone is a greenhouse gas, and sulfates and nitrates can reduce the amount of solar radiation reaching the earth, but EPA believes that we are unable to quantify any net climate-related disbenefit or benefit associated with the combined ozone and PM reductions in this rule.

Additionally, from analyses of the benefits of the Acid Rain Program, EPA has seen that substantial health and environmental benefits that are likely to occur for Canadians because 80 percent of the Canadian population lives within 40 miles of the US-Canada border.

TABLE IX–6—UNQUANTIFIED AND NON-MONETIZED EFFECTS OF THE TRANSPORT RULE

Pollutant/effect	Endpoint
PM: health [a]	Low birth weight.
	Pulmonary function.
	Chronic respiratory diseases other than chronic bronchitis.
	Non-asthma respiratory emergency room visits.
	UVb exposure (+/−) [c].
PM: welfare	Household soiling.
	Visibility in residential and non-class I areas.
	UVb exposure (+/−) [c].
	Global climate impacts [c].
Ozone: health	Chronic respiratory damage.
	Premature aging of the lungs.
	Non-asthma respiratory emergency room visits.
	Increased exposure to UVb (+/−) [c].
Ozone: welfare	Yields for:
	—Commercial forests.
	—Fruits and vegetables, and
	—Other commercial and noncommercial crops.
	Damage to urban ornamental plants.
	Recreational demand from damaged forest aesthetics.
	Ecosystem functions.
	Increased exposure to UVb (+/−) [c].
NO_2: health	Respiratory hospital admissions.
	Respiratory emergency department visits.
	Asthma exacerbation.
	Acute respiratory symptoms.
	Premature mortality.
	Pulmonary function.
NO_2: welfare	Commercial fishing and forestry from acidic deposition.
	Commercial fishing, agriculture and forestry from nutrient deposition.
	Recreation in terrestrial and estuarine ecosystems from nutrient deposition.

TABLE IX–6—UNQUANTIFIED AND NON-MONETIZED EFFECTS OF THE TRANSPORT RULE—Continued

Pollutant/effect	Endpoint
	Other ecosystem services and existence values for currently healthy ecosystems.
SO_2: health	Respiratory hospital admissions.
	Asthma emergency room visits.
	Asthma exacerbation.
	Acute respiratory symptoms.
	Premature mortality.
	Pulmonary function.
SO_2: welfare	Commercial fishing and forestry from acidic deposition.
	Recreation in terrestrial and aquatic ecosystems from acid deposition.
	Increased mercury methylation.

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] Cohort estimates are designed to examine the effects of long term exposures to ambient pollution, but relative risk estimates may also incorporate some effects due to shorter term exposures (*see* Kunzli *et al.* (2001) for a discussion of this issue). While some of the effects of short term exposure are likely to be captured by the cohort estimates, there may be additional premature mortality from short term PM exposure not captured in the cohort estimates included in the primary analysis.

[c] May result in benefits or disbenefits.

X. Economic Impacts

For the affected region, the projected annual private incremental costs of the proposed remedy option to the power industry are $3.7 billion in 2012 and $2.8 billion in 2014. For the State Budgets/Intrastate Trading remedy, projected annual private incremental costs are $4.2 billion in 2012 and $2.7 billion in 2014. Finally, for the direct control remedy, the projected annual private incremental costs are $4.3 billion in 2012 and $3.4 billion in 2014. These costs represent the private compliance cost to the electric generating industry of reducing NO_X and SO_2 emissions to meet the requirements set forth in the rule. Estimates are in 2006 dollars.

In estimating the net benefits of regulation, the appropriate cost measure is "social costs." Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule for the proposed remedy option are estimated to be approximately $2.0 billion in 2014 assuming a 3 percent discount rate. These costs become $2.2 billion in 2014 assuming a 7 percent discount rate. For the State Budgets/Intrastate Trading remedy, social costs are estimated to be approximately $2.5 billion in 2014 assuming a 3 percent discount rate and $2.7 billion in 2014 assuming a 7 percent discount rate. Finally, for the direct control remedy, social costs are estimated to be approximately $2.7 billion in 2014 assuming a 3 percent discount rate and $2.9 billion in 2014 assuming a 7 percent discount rate.

Overall, the economic impacts of the Transport Rule proposal are modest in 2014, particularly in light of the large benefits ($122 to $294 billion annually at a 3 percent discount rate and $111 to $266 billion annually at a 7 percent discount rate) we expect as shown earlier in this preamble (*see* section IX for more details). Ultimately, we believe the electric power industry will pass along most of the costs of the rule to consumers, so that the costs of the rule will largely fall upon the consumers of electricity. For more information on electricity price changes that result from this proposal, please refer to section XII.H (Statement of Energy Effects) later in this preamble.

For this proposed rule, EPA analyzed the costs using the Integrated Planning Model (IPM). The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for SO_2 and NO_X throughout the contiguous United States for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.* Analysis of impacts on affected industries outside of the electric power generating sector are estimated by the Economic Model for Policy Analysis (EMPAX), a dynamic model that can generate price and output changes for output affected by electricity price changes due to air pollution control policies and also estimates of social costs associated with such policies. Documentation for EMPAX can be found in the docket for this rulemaking or at *http://www.epa.gov/ttn/ecas/EMPAX.htm.*

Also note that as explained in section IV.A.3, the baseline used in this analysis assumes no CAIR. If EPA's base case analysis were to assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. As explained in that section, EPA believes that this is the most appropriate baseline to use for purposes of determining whether an upwind state has an impact on a downwind monitoring site in violation of section 110(a)(2)(D).

XI. Incorporating End-Use Energy Efficiency Into the Proposed Transport Rule

A. Background

EPA believes that achievement of energy efficiency improvements in homes, buildings, and industry is an important component of achieving emissions reductions from the power sector while minimizing associated compliance costs. By reducing electricity demand, energy efficiency avoids emissions of all pollutants associated with electricity generation, including emissions of NO_X and SO_2 targeted by this rule. While all remedy options considered—including the proposed remedy (State Budgets/Limited Trading)—will lead to a modest increase in the relative cost-effectiveness of energy efficiency investments by internalizing environmental costs associated with these pollutants, EPA is interested in considering additional means by which energy efficiency can be encouraged through this proposed rule.

1. What is end-use energy efficiency?

End-use energy efficiency (hereafter, "energy efficiency") in the context of this proposed rule refers to activities that reduce the demand for electricity from EGUs in affected states. Energy

efficiency improvements are pursued through the efforts of state agencies, independent program administrators (*e.g.* Vermont Energy Investment Corporation), electric utilities, energy service companies, and other commercial entities. Examples of common energy efficiency projects include re-commissioning of commercial buildings, rebates for energy efficient appliances, and home energy audits.

2. How does energy efficiency contribute to cost-effective reductions of air emissions from EGUs?

EPA recognizes that significant opportunity remains for energy efficiency improvements in businesses, homes, and industry. However, there are several informational and market barriers that limit investment in cost-effective energy efficient practices. Several federal programs authorized under the Act, including ENERGY STAR, are designed to address these barriers.

By reducing the demand for electricity energy efficiency reduces the need for investments in EGU emissions control technologies in order to meet the limits of an established state emissions budget and can often be implemented at a lower cost than traditional control technologies. Section III.E in this preamble further discusses the importance of electricity demand reductions as a component of EPA's broader air quality improvement strategy for the power sector.

EPA is available to assist states in quantifying the reduction in compliance costs of air regulatory programs, including the proposed rule, that can be realized through effective energy efficiency policies and programs.

3. How does the proposed rule support greater investment in energy efficiency?

By requiring reductions in the emissions of NO_X and SO_2 from power plants in affected states, a transport rule will lead to the internalization of costs associated with reducing the environmental effects of these pollutants. Since the economics of energy efficiency investments are directly related to power generation costs, this will improve the relative cost-effectiveness of these investments. Over time, this effect is expected to lead to increases in energy efficiency investments and associated benefits.

4. How have EPA and states previously integrated energy efficiency into air regulatory programs?

Congress, EPA, and states have all recognized the value of incorporating energy efficiency into air regulatory programs. Several allowance-based programs—including the Acid Rain Program, EPA's NO_X Budget Trading program, and the Regional Greenhouse Gas Initiative (an effort of 10 states from the Northeast and Mid-Atlantic regions)—have provided mechanisms for rewarding energy efficiency projects through either the award of emissions allowances, typically through the use of a fixed set-aside pool, or the use of revenues obtained through the auction of emissions allowances. The emissions caps established by these programs are unaffected by this approach, however, compliance costs are reduced (to the extent electricity demand reductions are realized) as are the emissions of non-capped pollutants from affected EGUs. In addition to these allowance-based programs, EPA has also established, through Guidance,[116] a means for recognizing the emissions benefits of energy efficiency in SIPs and has approved their use in individual state plans.

B. Incorporating End-Use Energy Efficiency Into the Transport Rule

As discussed previously, EPA believes that increasing end-use energy efficiency can be an effective approach for reducing compliance costs of the proposed rule, as well as for reducing EGU emissions that are not the target of this rule including mercury, other toxics, and carbon dioxide. While EPA believes the proposed rule will make energy efficiency investments more competitive, the Agency is seeking comments on additional ways in which this rule could further encourage these investments.

1. Options that Could Be Used To Incorporate Energy Efficiency Into Allowance Based Programs

As discussed previously, allowance-based programs (such as the proposed State Budgets/Limited Trading remedy and the alternative State Budgets/Intrastate Trading remedy) of EPA and states have supported energy efficiency projects through the use of auction revenues or the award of allowances. EPA considered these options in developing this proposal but, for the reasons described later, decided not to include either option in this proposal.

2. Why did EPA not propose these options?

The emissions reductions requirements of the proposed rule are implemented through proposed FIPs. This means, among other things, that EPA allocates the emission allowances directly to individual sources. In contrast, when allowance based programs are implemented through SIPs, states may have significant flexibility to determine the methodology used to allocate or auction allowances in their budgets. Under the proposed FIPs, EPA would allocate allowances to sources in a manner consistent with the methodology used to determine each state's budget. EPA believes this approach is appropriate because of the link between the allowance allocation methodology and the significant contribution determinations. EPA requests comment on whether EPA has authority to and whether it would be appropriate for EPA to consider energy efficiency considerations in developing the allowance allocation methodology.

In addition, because the emission reduction requirements are implemented through FIPs, any auction of allowances would be conducted by EPA. As discussed previously in section V.D.5.b, pursuant to the Miscellaneous Receipts Act, any revenues from a federal auction of allowances must go to the U.S. Treasury. This precludes the use of proceeds from such an auction to reward energy efficiency projects.

In addition, and as also discussed previously in sections III.A and III.B.3, EPA anticipates further revisions to the $PM_{2.5}$ and ozone NAAQS and intends to issue subsequent proposals to address the interstate transport requirements of section 110(a)(2)(D)(i)(I) with respect to those new NAAQS. The emissions reductions requirements identified in any such rules could be implemented through SIPs. The SIP process could give states significant flexibility in regards to allocation and auctioning of allowances. This flexibility could be used by states to support energy efficiency projects through the use of auction revenues or the award of allowances.

EPA is seeking comment on the discussion within this section and the use of these and other approaches for encouraging energy efficiency within the proposed rule.

XII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4,

[116] U.S. EPA. 2004. Guidance on State Implementation Plan (SIP) Credits for Emission Reductions From Electric-Sector Energy Efficiency and Renewable Energy Measures. August. *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf.*

1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action.

When estimating the $PM_{2.5}$- and ozone-related human health benefits and compliance costs in Table 1 below, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of the preferred and alternate Transport Rule remedies considered by the Agency. The Regulatory Impacts Analysis (RIA) available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below.

When characterizing uncertainty in the PM-mortality relationship, EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, EPA's 2009 Integrated Science Assessment (ISA) for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. In the RIA accompanying this rule, rather than segmenting out impacts predicted to be associated levels above and below a 'bright line' threshold, EPA includes a "lowest-measured-level (LML)" that illustrates the increasing uncertainty that characterizes impacts attributed to levels of $PM_{2.5}$ below the LML for each study. Figure 5–19 shows the distribution of avoided PM mortality impacts predicted relative to the baseline (*i.e.* pre-Transport Rule) $PM_{2.5}$ levels experienced by the population receiving the $PM_{2.5}$ mortality benefit in 2014 (Figure 5–19). This figure also shows the lowest air quality levels measured in each of the two primary epidemiological studies EPA uses to quantify PM-related mortality. This information allows readers to determine the portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction $PM_{2.5}$-related premature mortality decreases in areas where annual mean $PM_{2.5}$ levels are further below the LML in the two epidemiological studies. In this analysis, we see that about 80% of the estimated benefits accrue among populations exposed to annual mean $PM_{2.5}$ levels above 10ug/m3 (the LML in the Six Cities study) and 97% of the estimated benefits are associated with PM levels above 7.5 mg/m3 (the LML in the American Cancer Society study used for this analysis). While the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Table XII.A–1 shows the results of the cost and benefits analysis for the proposed and alternate remedies.

TABLE XII.A–1—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF VERSIONS OF THE PROPOSED REMEDY OPTION IN 2014 [a]

[Billions of 2006$]

Description	Preferred remedy-State budgets/ limited trading	Direct control	Intrastate trading
Social costs [b]			
3% discount rate	$2.03	$2.68	$2.49.
7% discount rate	$2.23	$2.91	$2.70.
Health-related benefits [c,d]			
3% discount rate	$118 to $288 + B	$117 to $286 + B	$113 to $276 + B.
7% discount rate	$108 to $260 + B	$108 to $262 + B	$104 to $252 + B.
Net benefits (benefits-costs)			
3% discount rate	$116 to $286	$115 to $283	$110 to $273.
7% discount rate	$105 to $258	$105 to $259	$101 to $249.

Notes: (a) All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for the year 2014. For notational purposes, unquantified benefits are indicated with a "B" to represent the sum of additional monetary benefits and disbenefits. Data limitations prevented us from quantifying these endpoints, and as such, these benefits are inherently more uncertain than those benefits that we were able to quantify. A listing of health and welfare effects is provided in RIA Table 1–6. Estimates here are subject to uncertainties discussed further in the body of the document. (b) The social costs are the loss of household utility as measured in Hicksian equivalent variation. (c) The reduction in premature mortalities account for over 90% of total monetized benefits. Benefit estimates are national. Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 5. Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000; OMB, 2003). The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in chapter 5. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). Monetized benefits do not include unquantified benefits, such as other health effects, reduced sulfur deposition or visibility. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. (d) Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in RIA Table 1–4.

B. Paperwork Reduction Act

The information collection requirements in the proposed rule have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them.

The information collection activities in this proposed rule include monitoring and the maintenance of records. The information generated by these activities will be used by EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable EPA or states to identify affected facilities that may not be in compliance with the requirements. Based on reported information, EPA

will decide which units and what records or processes should be inspected. The amendments do not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

The record-keeping and reporting burden to sources resulting from states choosing to participate in a regional cap-and-trade program is approximately $28 million annually. This estimate includes the annualized cost of installing and operating appropriate SO_2 and NO_X emissions monitoring equipment to measure and report the total emissions of these pollutants from affected EGUs (serving generators greater than 25 megawatt electrical). The burden to state and local air agencies includes any necessary SIP revisions, performance of monitoring certification, and fulfilling of audit responsibilities. More information on the ICR analysis is included in the proposed Transport Rule docket. Burden is defined at 5 CFR 1320.3(b).

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201. For the electric power generation industry, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million megawatt-hours (MW-hr) or less in the previous fiscal year.

(2) A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

TABLE XII.C–1—POTENTIALLY REGULATED CATEGORIES AND ENTITIES [a]

Category	NAICS Code [b]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal Government	[c] 221112	Fossil fuel-fired electric utility steam generating units owned by the federal government.
State/Local	[c] 221112	Fossil fuel-fired electric utility steam generating units owned by municipalities.
Tribal Government	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

[a] Include NAICS categories for source categories that own and operate electric generating units only.
[b] North American Industry Classification System.
[c] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of this proposed rule on small entities, EPA is certifying that this action will not have a significant economic impact on a substantial number of small entities. This certification is based on the economic impact of this proposed action to all affected small entities across all industries affected. EPA has assessed the potential impact of this action on small entities and found that approximately 550 of the estimated 4,700 EGUs potentially affected by today's proposal are owned by the 81 potentially affected small entities identified by EPA's analysis. EPA estimates that 30 of the 81 identified small entities will have annualized costs greater than 1 percent of their revenues, and the other 51 are projected to incur costs less than 1 percent of revenues. While there are costs greater than 1 percent of revenues for a number of small entities, EPA is certifying No SISNOSE for several reasons. First, of the 30 entities projected to have costs greater than 1 percent of revenues, around 75 percent of them operate in cost of service regions and would generally be able to pass any increased costs along to rate-payers. This is one of the primary reasons given in the Regulatory Impact Assessment for the Final Clean Air Interstate Rule (EPA–452/R–05–002 March 2005) that supported EPA's "No SISNOSE" certification in the final CAIR FIP rule on April 28, 2006 (71 FR 25366). Furthermore, of the approximately 550 units identified by EPA as being potentially owned by small entities, approximately two-thirds of the units that have higher costs are not expected to make operational changes as a result of this rule (*e.g.*, install control equipment or switch fuels). Their increased costs are largely due to increased cost of the fuel they would be expected to use whether or not they had to comply with the proposed rule. Further, increased fuel costs are often passed through to rate-payers as common practice in many areas of the United States due to fuel adder arrangements instituted by state public utility commissions. In addition, EPA's decision to exclude units smaller than 25 MWe has already significantly reduced the burden on small entities. Hence, EPA has concluded that there is no SISNOSE for this rule.

For more information on the small entity impacts associated with the proposed rule, please refer to the Economic Impact and Small Business Analyses in the public docket. These analyses can be found in the Regulatory Impact Analysis for this proposed rule. Finally, although EPA believes that the proposed rule would not have a significant economic impact on a

substantial number of small entities, EPA plans to take steps to conduct meetings with industry trade associations to discuss regulatory options and ensure that the burdens imposed on small entities are minimal.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. This rule contains a Federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, EPA has prepared under section 202 of the UMRA a written statement which is summarized later.

Consistent with section 205, EPA has identified and considered a reasonable number of regulatory alternatives. In today's action, EPA has included three remedy options that it considered when developing this proposed rule: (1) The proposed remedy of State Budgets/Limited Trading, (2) State Budgets/Intrastate Trading, and (3) Direct Controls. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

EPA examined the potential economic impacts on state and municipality-owned entities associated with this rulemaking based on assumptions of how the affected states will implement control measures to meet their emissions. Although EPA does not conclude that the requirements of the UMRA apply to the Transport Rule, these impacts have been calculated to provide additional understanding of the nature of potential impacts and additional information.

According to EPA's analysis, of the 84 government entities considered in this analysis and the 482 government entities in the Transport Rule region that are included in EPA's modeling, 27 may experience compliance costs in excess of 1 percent of revenues in 2014, based on our assumptions of how the affected states implement control measures to meet their emissions budgets as set forth in this rulemaking.

Government entities projected to experience compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the Transport Rule. However, as noted previously, it is EPA's position that because these government entities can pass on their costs of compliance to rate-payers, they will not be significantly affected. Furthermore, the decision to include only units greater than 25 MW in size exempts 380 government entities that would otherwise be potentially affected by the Transport Rule. For more information on the impacts estimated for this analysis, please refer to the RIA for this proposed rule.

In addition, before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA, a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements. Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA has initiated consultations with governmental entities affected by this rule.

The EPA has determined that this rule contains a Federal mandate that may result in expenditures of $100 million or more in 1 year. EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments and that development of a small government plan under section 203 of the Act is not required. The costs of compliance will be borne predominately by sources in the private sector although a small number of sources owned by state and local governments may also be impacted. The requirements in this action do not distinguish EGUs based on ownership, either for those units that are included within the scope of the rule or for those units that are exempted by the generating capacity cut-off. Therefore, this rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The proposed rule primarily affects private industry, and does not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to the proposed rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA will specifically solicit comment on the proposed rule from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the final rule.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the emissions reductions from the strategies in this rule will further improve air quality and will further improve children's health.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as "significant energy actions." Section 4(b) of Executive Order 13211 defines "significant energy

action" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." This proposed rule is a significant regulatory action under Executive Order 12866, and this proposed rule may have a significant adverse effect on the supply, distribution, or use of energy.

Under the provisions of this proposed rule, EPA projects that approximately 1.2 GW of coal-fired generation may be removed from operation by 2014. In practice, however, the units projected to be uneconomic to maintain may be "mothballed," retired, or kept in service to ensure transmission reliability in certain parts of the grid. These units are predominantly small and infrequently used generating units dispersed throughout the area affected by the rule. Assumptions of higher natural gas prices or electricity demand would create a greater incentive to keep these units operational. The EPA projects that the average retail electricity price could increase nationally by less than 2.5 percent in 2012 and 1.5 percent in 2014. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, delivered coal prices increase by about 7 percent in 2012 and 4 percent in 2014 as a result of higher demand for lower-sulfur coals. The EPA also projects that natural gas prices will increase by less than 1.7 percent in 2012 and 0.5 percent in 2014 and that natural gas use for electricity generation will increase by less than 73 million mcf by 2014. The price increase is also within the range we regularly see in delivered natural gas prices. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 3 million tons in 2012 and 9 million tons in 2014. The EPA does not believe that this rule will have any other impacts that exceed the significance criteria.

The EPA believes that a number of features of the proposed rulemaking serve to reduce its impact on energy supply. First, the trading programs in State Budgets/Limited Trading provide considerable flexibility to the power sector and enable industry to comply with the emission reduction requirements in the most cost-effective manner, thus minimizing overall costs and the ultimate impact on energy supply. Second, the more stringent budgets for SO_2 are set in two phases, providing adequate time for EGUs to install pollution controls. In addition, both the operational flexibility of trading and the ability to bank allowances for future years helps industry plan for and ensure reliability in the electrical system. For more details concerning energy impacts, *see* the RIA for the proposed Transport Rule.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rule would require all sources to meet the applicable monitoring requirements of 40 CFR part 75. Part 75 already incorporates a number of voluntary consensus standards.

Consistent with the Agency's Performance Based Measurement System (PBMS), Part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in Part 75. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to Part 75; however, EPA periodically revises the test procedures set forth in Part 75.

When EPA revises the test procedures set forth in Part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in Part 75, EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under 40 CFR 75.66 before they are used.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority, low-income, and Tribal populations in the United States.

1. Consideration of Environmental Justice Issues in the Rule Development Process

In the rulemaking process, EPA considers whether there are positive or negative impacts of the action that appear to affect low-income, minority, or Tribal communities disproportionately, and, regardless of whether a disproportionate effect exists, whether there is a chance for these communities to meaningfully participate in the rulemaking process. EPA expects that this rule, "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone," will provide significant health and environmental benefits to, among others, people with asthma, people with heart disease, and people living in ozone or fine particle ($PM_{2.5}$) nonattainment areas. This rule also has the potential to affect the cost structure of the utility industry and could lead to regional shifts in electricity generation and/or emissions of various pollutants. Therefore we expect this rule to be of interest to many environmental justice communities. EPA's analysis of the effects of this proposed rule, including information on air quality changes and the resulting health benefits, is presented both in section IX of this preamble and in more detail in the air quality modeling Technical Support Document and the Regulatory Impact Analysis (RIA) for this rule. These documents can be accessed through the rule docket No. EPA–HQ–OAR–2009–0491 and from the main EPA Web page for the rule *http://www.epagov/airtransport.* This section summarizes the legal basis for this rule, and provides background information on how this rule fits into the larger regulatory strategy for controlling

pollution from the power sector. A summary of the emissions, air quality, and health benefit estimates for this rule then follows.

This rule is replacing an earlier rule (the 2005 Clean Air Interstate Rule (CAIR)) that was first vacated and then remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit. CAIR was vacated by the U.S. Court of Appeals for the District of Columbia Circuit in July 2008 in a case known as *North Carolina* v. *EPA.* In December 2008, the vacatur was altered to a remand based on the likely environmental harms of vacating the rule and EPA's stated intent to replace the rule promptly. At the time of the 2008 court ruling, many sources had already begun to install and run emissions control devices or otherwise alter their operations and had successfully begun reducing their emissions. The court decision has led to significant uncertainty among affected sources as to what emissions reductions will be required and among states and communities as to what air quality benefits will be achieved. By proposing this aggressive replacement rule that meets the legal requirements of the CAA as interpreted by the Court in the *North Carolina* decision promptly, EPA is both maximizing the likelihood that the goals of the CAA will be met, and helping communities receive the air quality benefits they need as quickly as possible by minimizing the chance that any emissions reductions achieved under CAIR would be lost.

It is important to note that CAA section 110(a)(2)(d), which addresses transport of criteria pollutants between states and is the authority for this rule, is only one of many provisions of the CAA that provide EPA, states, and local governments with authorities to reduce exposure to ozone and $PM_{2.5}$ in communities. These legal authorities work together to reduce exposure to these pollutants in communities, including environmental justice communities, and provide substantial health benefits to both the general public and sensitive sub-populations.

This proposed rule is one of a group of regulatory actions that EPA will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to ozone and $PM_{2.5}$, as well as to other pollutants, from power plants and other sources. To the extent that EPA has the legal authority to do so while fulfilling its obligations under the CAA and other relevant statutes, we will also coordinate these utility-related air pollution rules with upcoming regulations for the power sector from EPA's Office of Water (OW) and its Office of Resource Conservation and Recovery (ORCR). The primary actions are outlined below and presented in more detail in section III.E of this preamble.

Beyond this action and any additional efforts undertaken in response to comment, other rules that will drive the creation of a clean, efficient and completely modern power sector include: CAA section 112(d) standards (one of which is often referred to as a Maximum Achievable Control Technology (MACT) standard) to reduce emissions of air toxics, including mercury, and particles from coal- and oil-fired power plants; new National Ambient Air Quality Standards (NAAQS) for ozone, $PM_{2.5}$, sulfur dioxide, and nitrogen oxides; potentially one or more additional rules eliminating interstate transport of emissions that contribute significantly to nonattainment and maintenance areas for the new ozone and $PM_{2.5}$ NAAQS as necessary; revisions to the New Source Performance Standards (NSPS) for steam electric generating units; and best available retrofit technology (BART) requirements and other requirements that address visibility and regional haze. Within the planning and investment horizon for compliance with these rules, EPA very likely will be compelled to respond to a pending petition to set standards for the emissions of greenhouse gases (GHGs) from steam electric generating units under the New Source Performance Standard program. Furthermore, as set forth in the recently promulgated reinterpretation of the Johnson Memo, beginning in 2011 new and modified sources of GHG emissions, including EGUs, will be subject to permits under the Prevention of Significant Deterioration program requiring them to adopt Best Available Control Technology for their GHGs. Finally, EPA will pursue energy efficiency improvements in the use of electricity throughout the economy, along with other federal agencies, states and other groups, which will contribute to additional environmental and public health improvements that the Agency wants to provide while lowering the costs of realizing those improvements.

Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from environmental justice communities, among many others. EPA intends to provide multiple opportunities for comment on these actions, including during the comment process for this rule, and encourages environmental justice communities to review and comment on them.

2. Potential Environmental and Public Health Impacts to Vulnerable Populations

There are several considerations to take into account when assessing the effects of this proposed rule on minority, low-income, and tribal populations. These include: Amount of emissions reductions and where they take place (including any potential for areas of increased emissions); the changes in ambient concentrations across the affected area; and the health benefits expected from the rules.

Emissions reductions. This proposed rule will reduce exposure to $PM_{2.5}$ and ozone pollution in most eastern states by reducing interstate transport of these pollutants and their chemical precursors (sulfur dioxide (SO_2) and nitrogen oxides (NO_X)). This rule has the effect of reducing emissions of these pollutants that affect the most-contaminated areas (*i.e.* areas that are not meeting the 1997 and 2006 ozone and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS)). This rule separately identifies both nonattainment areas and maintenance areas (maintenance areas are those that currently meet the NAAQS but that, based on past data, are in danger of exceeding the standards in the future). This approach of requiring emissions reductions to protect maintenance areas as well as nonattainment areas reduces the likelihood that any areas close to the level of the standard will exceed the current health-based standards in the future.

Ozone and $PM_{2.5}$ concentrations in both nonattainment and maintenance areas identified in this rule are the result of both local emissions and long-range transport of pollution. This rule requires upwind states to reduce or eliminate their significant contribution to nonattainment or maintenance problems in downwind states. Even when the significant contributions of upwind states are fully eliminated, additional emissions reductions within the nonattainment area and/or the downwind state will be needed for some areas to attain and maintain the NAAQS.

The proposed remedy option for this rule would use a limited emissions trading mechanism among power plants to achieve significant emissions reductions in states covered by the rule. EPA recognizes that many environmental justice communities have voiced concerns about emissions trading and any resulting potential for any emissions increases in any location.

This proposed rule uses EPA's authority in CAA § 110(a)(2)(d) to require states to eliminate emissions from power plants in their state that contribute significantly to downwind $PM_{2.5}$ or ozone nonattainment or maintenance areas. EPA's proposed mechanism for achieving these emissions reductions is to use a tightly constrained trading program that requires a strict emission ceiling in each state while allowing a limited ability to shift emissions between facilities or states. This approach ensures that emissions in each state that significantly contribute to downwind nonattainment or maintenance areas are controlled, while allowing power companies to adjust generation based on fluctuations in electricity demand, weather, availability of low-emitting power sources (*e.g.* temporary shut-down of a nuclear power plant for maintenance or repairs), or other unanticipated factors affecting the interconnected electricity grid.

Any emissions above the state's allocated level must be offset by emissions reductions from another state in the region below that state's budget or by using extra "banked" allowances from earlier years. All sources must hold enough allowances to cover their emissions; therefore, if they emit more than their allocation they must buy allowances from another source that emitted less than its allocation. $PM_{2.5}$ and ozone pollution from power plants have both local and regional components: Part of the pollution in a given location—even in locations near emissions sources—is due to emissions from nearby sources and part is due to emissions that travel hundreds of miles and mix with emissions from other sources. Therefore, in many instances the exact location of the upwind reductions does not affect the levels of air pollution downwind.

It is important to recognize that the section of the Clean Air Act providing authority for this rule, 110(a)(2)(D), unlike some other provisions, does not dictate levels of control for particular facilities. None of EPA's alternatives within this proposal can ensure there will be no emission increases at any facility. Under the direct control alternative, the emissions rate for each facility is reduced but each facility could emit more by increasing their power output in order to meet electricity reliability or other goals. Under the intrastate trading option, state emissions must stay constant but individual facilities within each state could increase their emissions as long as another facility in the state had decreased theirs. By strictly setting state budgets to eliminate significant contributions to non-attainment and maintenance areas that EPA has identified in this action, by limiting the amount of interstate trading possible and by requiring any emissions above the level of the allocations to be offset by emission decreases elsewhere in the region, the proposed remedy options reduce ambient concentrations where they are most needed.

EPA's emissions modeling data indicate that nationwide SO_2 emissions from electric generating units (EGUs) will be approximately 6.4 million tons (60 percent) lower in 2014 than they were in 2005 (which is the year that the Clean Air Interstate Rule was finalized). Emissions would also decrease when compared to the base case (the base case estimates of SO_2 emissions in 2014 in the absence of this proposed rule or the Clean Air Interstate Rule it is replacing). SO_2 emissions under this proposed rule are projected to be approximately 4.4 million tons (50%) lower than they would have been in 2014 in the base case (*i.e.* without this rule).

EPA's modeling does project that some states not covered by one or more aspects of the program may experience increases of SO_2 emissions (*i.e.*, their emissions are greater in the control case modeling than in the base case modeling). These emission increases are the result of forecasted changes in operation of units outside of the controlled region (due to the interconnected nature of the utility grid or influence of the rule on the market for lower sulfur coal). As shown in Table IV.D.6, Arkansas, Mississippi, North Dakota, South Dakota, and Texas all exhibit 2012 SO_2 emissions increases over the base case of more than 5,000 tons. Texas is projected to have by far the largest increase (136,000 tons), while the other states' increases ranges from 6,000 to 32,000 tons. Further analysis with the simplified air quality assessment tool indicates that these projected increases in the Texas SO_2 emissions would increase Texas's contribution to an amount that would exceed the 0.15 $\mu g/m^3$ threshold for annual $PM_{2.5}$. For this reason, EPA requests comment on whether Texas should be included in the program as a group 2 state. For additional details, *see* section IV.D of this preamble.

With the exception noted above, EPA is not proposing for the SO_2 portion of this rule to cover the states where SO_2 emissions are projected to increase because EPA has not found, at this time, that they contribute significantly to nonattainment or interfere with maintenance of the $PM_{2.5}$ NAAQS in downwind areas. EPA's authority under § 110(a)(2)(d)(i)(I) is limited to addressing any such significant contribution and interference with maintenance. EPA anticipates that additional rulemakings affecting utilities that will be proposed soon, such as the CAA Section 112(d) standards, would apply nationwide and result in significant additional SO_2 reductions.

EPA's emissions modeling data indicates that nationwide ozone season NO_X emissions from EGUs will be approximately 400,000 tons (30%) lower in 2014 than they were in 2005 (before implementation of the Clean Air Interstate Rule). Emissions would also decrease compared to the base case. Ozone season NO_X emissions from EGUs under this proposed rule are projected to be approximately 150,000 tons (15%) lower than they would have been in 2014 in the base case (*i.e.* without this rule). EPA anticipates that additional upcoming actions, and likely additional interstate transport reductions to help states attain the proposed 2010 ozone NAAQS, will result in significant additional NO_X reductions.

EPA anticipates that this proposed action will significantly reduce, but not eliminate, the number of nonattainment and maintenance areas for the 1997 ozone and $PM_{2.5}$ and 2006 $PM_{2.5}$ NAAQS. Table IX–1 lists the changes in number of nonattainment sites. Most of these sites are located in urban areas. A single nonattainment area usually contains multiple monitoring sites; therefore there are more nonattainment sites than nonattainment counties or areas. As discussed in detail in section IV.D of this preamble, where this proposal does not fully quantify all of the significant contribution and interference with maintenance, EPA intends to address these additional requirements quickly. To the extent possible, EPA will supplement this proposed notice with additional information so that we can provide downwind states with all the certainty about upwind emissions reductions they need to address their own local nonattainment concerns. In addition, as stated above, elimination of these nonattainment areas may require both local and regional emissions reductions and this proposed action seeks only to address the regional transport component.

As a result of these SO_2 and NO_X reductions, EPA's air quality modeling indicates that concentrations of fine particles will decline throughout the eastern U.S. and in all the states affected by this rule. These reductions are largest in the area of the Ohio River valley and

neighboring states and extend east through New England, west to Texas, south to Florida, and north through the Great Lakes states. "Border" states immediately outside the transport region are also predicted to see reductions in air concentrations, even though emissions increase in some of these states. This is because concentrations of fine particles in most locations are composed of both local emissions and those transported over hundreds of miles and emissions reductions far away can cause significant improvements in local air quality.

The modeling suggests also that there may be some small increases in $PM_{2.5}$ near locations in the western U.S. where SO_2 emissions are forecast to increase. These increases are small compared to the reductions predicted to take place in the eastern U.S. The increases are due to the regional nature of this rule (*i.e.* these states are not covered because sources in these states have not been found to contribute significantly to downwind nonattainment or maintenance areas) and the national nature of both coal markets and the Acid Rain Program allowance market. They are not the result of any particular type of remedy option (*e.g.* trading). EPA anticipates that future rulemakings, such as CAA section 112(d) standards and anticipated revisions to the 2006 fine particulate standards, are likely to reduce emissions in the areas not covered by this rule.

EPA's air quality modeling also indicates that concentrations of ozone will decline in much of the eastern U.S. These reductions are largest along much of the Gulf Coast and in Florida and in a region encompassing western Wisconsin, Iowa, Kansas, Missouri, Arkansas, and northeastern Oklahoma. These areas with the largest reductions are roughly the area immediately outside the boundaries of the NO_X SIP Call region. States in the SIP Call region were required to make significant reductions in NO_X beginning in 2003 and these emissions reductions are included in the baseline modeling for this proposed Transport Rule and therefore not captured as additional benefits of this rulemaking.

As is common when modeling many NO_X control strategies, the air quality modeling for this proposed rule also suggests there may be a few small, localized areas in the eastern U.S. where there are small increases in ozone concentrations. These generally small increases are a result of reductions in NO_X emissions in these local areas; they do not appear to represent a lack of NO_X emissions reductions or be the result of any specific emission control strategy (*e.g.* any type of trading). Rather, this phenomenon can result from complex atmospheric chemistry reactions taking place among chemical constituents of air pollution in these areas. Due to the complex photochemistry of ozone production, NO_X emissions lead to both the formation and destruction of ozone, depending on the relative quantities of NO_X, volatile organic compounds, and ozone formation catalysts. In the 2014 base case, NO_X emissions from sources in a few locations act to "quench" (*i.e.*, lower) ozone compared to ozone concentrations in surrounding areas. The application of NO_X controls in these areas reduces this quenching effect, thereby increasing ozone to levels generally on par with those of the surrounding area. In this case it is uncertain whether the structure of the model itself is potentially exacerbating the spatial extent or magnitude of any ozone increases which might actually occur as a result of this rule. It should be noted that these same NO_X emissions reductions that might be causing extremely localized ozone increases are certainly causing larger, more widespread improvements in ozone concentrations in downwind areas. Finally, as stated above, it is important to note that EPA intends to promulgate additional rules over the next few years that will further reduce concentrations of ozone and $PM_{2.5}$ and that the federal government and the states can and do use many different legal authorities to limit exposure to ozone.

Health benefits. This rule reduces concentrations of $PM_{2.5}$ and ozone pollution, exposure to which can cause, or contribute to, adverse health effects including premature mortality and many types of heart and lung diseases that affect many minority and low-income individuals, and Tribal communities. $PM_{2.5}$ and ozone are particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure to these pollutants can cause premature death and trigger heart attacks, asthma attacks in those with asthma, chronic and acute bronchitis, emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. High rates of both heart disease and asthma are a cause for concern in many environmental justice communities, making these populations more susceptible to air pollution health impacts. In addition, many individuals in these communities also lack access to high quality health care to treat these illnesses.

We estimate that in 2014 the PM-related annual benefits of the proposed remedy option include approximately 14,000 to 36,000 fewer premature mortalities, 9,200 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 11,000 fewer hospitalizations (for respiratory and cardiovascular disease combined), 10 million fewer days of restricted activity due to respiratory illness and approximately 1.8 million fewer lost work days. We also estimate substantial health improvements for children in the form of fewer cases of upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the eastern U.S.). Based upon modeling for 2014, annual ozone related health benefits are expected to include between 50 and 230 fewer premature mortalities, 690 fewer hospital admissions for respiratory illnesses, 230 fewer emergency room admissions for asthma, 300,000 fewer days with restricted activity levels, and 110,000 fewer days where children are absent from school due to illnesses. When adding the PM and ozone-related mortalities together, we find that the proposed remedy option for this rule will yield between 14,000 and 36,000 fewer premature mortalities. EPA has also estimated the benefits of the alternate remedies in this proposal using a benefit-per-ton estimation approach and found they would provide similar benefits.

It should be noted that, as discussed in the RIA for this action, there are other benefits to the emissions reductions discussed here, such as improved visibility and, indirectly, reduced mercury deposition. Additional benefits of reducing emissions of SO_2 include reduced acidification of lakes and streams, and reduced mercury methylation; additional benefits of NO_X reductions include reduced acidification of lakes and streams and reduced coastal eutrophication. Conversely, it is possible that the modest increases in emissions modeled for this rule in some western areas could result in limited increases of one or more of these effects in these locations.

3. Meaningful Public Participation

As EPA began considering approaches to address the court remand of the 2005 Clean Air Interstate Rule, the agency also began gathering input from a larger range of stakeholders. In the spring of 2009, EPA held a series of listening

sessions to gather information and perspectives from stakeholders prior to the formal start of the rulemaking process. These stakeholders included a number of environmental groups who requested that EPA consider several potential environmental justice issues during development of this rule. In addition, many environmental justice organizations were represented at a November 2009 EPA-Health and Human Services White House Stakeholder Briefing entitled "The Public Health Benefits of Energy Reform" in which EPA discussed our intention to propose this rule in the spring of 2010 and participants had the opportunity to respond. Finally, EPA notified tribes of our intent to propose this rule in the fall of 2009 during a regularly scheduled meeting to update the National Tribal Air Association members of upcoming EPA policies and regulations and to receive input from them on the effects of these efforts in Indian country. These were not opportunities for stakeholders to comment on the specifics of this proposal, as they took place prior to the development of this proposal, but they provided valuable information that EPA used in developing this proposal.

Upon proposal of this action, the Agency will begin an outreach effort with environmental justice communities, the public, the regulated community, state air regulators, and others to (1) describe the Transport Rule proposal, (2) provide information on the 2011 CAA Section 112 (d) and other upcoming EPA rulemakings affecting the power sector, and (3) listen to comments from stakeholders. The intent will be to inform all stakeholders of the industry's obligations and opportunities for the industry to use investments in SO_2 and NO_X reductions to help smooth transition to the CAA Section 112(d) standards compliance in late 2014. EPA intends to continue these efforts over time as more information becomes available in the development of the various rulemakings under development for the power sector.

During the comment period for this proposed rule, EPA intends to reach out specifically to environmental justice communities and organizations to notify them of the opportunity to provide comments on this rule and to solicit their comments on both this rule and the upcoming actions described above and in section III.E. EPA will hold public hearings on this rule; see the information at the very beginning of this preamble for locations, times and dates. Comments can also be submitted in writing or electronically by following the instructions at the beginning of this preamble.

4. Summary

EPA believes that the vast majority of communities and individuals in areas covered by this rule, including numerous low-income, minority, and Tribal communities in both rural areas and inner cities in the East, will see significant improvements in air quality and resulting improvements in health. EPA also recognizes that there is the potential for a number of communities or individuals outside the region covered by this rule to experience slightly worse air quality as an indirect result of emissions reductions required under this proposal. EPA requests comment on the impacts of this proposed action on low income, minority, and Tribal communities. EPA will further analyze environmental justice issues related to the impacts of the rule on those communities based both on additional data that may be developed and on comments on those issues prior to final action on this rule.

List of Subjects

40 CFR Part 51

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 52

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Parts 72

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 78

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 97

Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: July 6, 2010.

Lisa P. Jackson,

Administrator.

For the reasons set forth in the preamble, parts 51, 52, 72, 78, and 97 of chapter I of title 40 of the Code of Federal Regulations are proposed to be amended as follows:

PART 51—[AMENDED]

1. The authority citation for Part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

§ 51.121 [Amended]

2. Section 51.121 is amended by revising paragraph (r)(2) by removing the words "§ 51.123(bb)" and adding, in their place, the words "§ 51.123(bb) with regard to an ozone season that occurs before January 1, 2012".

§ 51.123 [Amended]

3. Section 51.123 is amended by adding a new paragraph (ff) to read as follows:

§ 51.123 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen pursuant to the Clean Air Interstate Rule.

* * * * *

(ff) Notwithstanding any provisions of paragraphs (a) through (ee) of this section, subparts AA through II and AAA through III of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS and the 8-hour ozone NAAQS meeting the requirements of paragraphs (b) through (ee) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, or in any emissions trading program provisions in a State's SIP approved under this section; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

§ 51.124 [Amended]

4. Section 51.124 is amended by adding a new paragraph (s) to read as follows:

§ 51.124 Findings and requirements for submission of State implementation plan revisions relating to emissions of sulfur dioxide pursuant to the Clean Air Interstate Rule.

* * * * *

(s) Notwithstanding any provisions of paragraphs (a) through (r) of this section, subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS meeting the requirements of paragraphs (b) through (r) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, or in any emissions trading program in a State's SIP approved under this section; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

§ 51.125 [Reserved]

5. Section 51.125 is removed and reserved.

PART 52—[AMENDED]

6. The authority citation for Part 52 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—General Provisions

§ 52.35 [Amended]

7. Section 52.35 is amended by adding a new paragraph (f) to read as follows:

§ 52.35 What are the requirements of the Federal Implementation Plans (FIPs) for the Clean Air Interstate Rule (CAIR) relating to emissions of nitrogen oxides?

* * * * *

(f) Notwithstanding any provisions of paragraphs (a) through (d) of this section, subparts AA through II and AAAA through IIII of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) through (d) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

§ 52.36 [Amended]

8. Section 52.36 is amended by adding a new paragraph (e) to read as follows:

§ 52.36 What are the requirements of the Federal Implementation Plans (FIPs) for the Clean Air Interstate Rule (CAIR) relating to emissions of sulfur dioxide?

* * * * *

(e) Notwithstanding any provisions of paragraphs (a) through (c) of this section, subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraphs (a) through (e) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

9. Subpart A is amended by adding §§ 52.37 and 52.38 to read as follows:

§ 52.37 What are the requirements of the Federal Implementation Plans (FIPs) under the Transport Rule (TR) relating to emissions of nitrogen oxides?

(a)(1) The TR NO_X Annual Trading Program provisions of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to annual emissions of nitrogen oxides (NO_X).

(2) The provisions of subpart AAAAA of part 97 of this chapter, regarding the TR NO_X Annual Trading Program, apply to the sources in the following States: Alabama, Connecticut, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

(3) Following promulgation of an approval by the Administrator of a State's SIP as correcting the SIP's deficiency that is the basis for this Federal Implementation Plan, the provisions of paragraph (a)(2) of this section will no longer apply to the sources in the State, unless the Administrator's approval of the SIP is partial or conditional.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of such approval of the State's SIP, the Administrator has already allocated any TR NO_X Annual allowances to sources in the State for any years, the provisions of part 97 of this chapter authorizing the Administrator to complete the allocation of TR NO_X Annual allowances for those years shall continue to apply, unless provided otherwise by such approval of the State's SIP.

(b)(1) The TR NO_X Ozone Season Trading Program provisions of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to emissions of NO_X during the ozone season, defined as May 1 through September 30 of a calendar year.

(2) The provisions of subpart BBBBB of part 97 of this chapter, regarding the TR NO_X Ozone Season Trading Program, apply to sources in each of the following States: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia.

(3) Following promulgation of an approval by the Administrator of a State's SIP as correcting the SIP's deficiency that is the basis for this Federal Implementation Plan, the provisions of paragraph (b)(2) of this section will no longer apply to sources in the State, unless the Administrator's approval of the SIP is partial or conditional.

(4) Notwithstanding the provisions of paragraph (b)(3) of this section, if, at the time of such approval of the State's SIP, the Administrator has already allocated any TR NO_X Ozone Season allowances to sources in the State for any years, the provisions of part 97 of this chapter authorizing the Administrator to complete the allocation of TR NO_X Ozone Season allowances for those years shall continue to apply, unless provided otherwise by such approval of the State's SIP.

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Transport Rule (TR) relating to emissions of sulfur dioxide?

(a) The TR SO_2 Group 1 Trading Program and TR SO_2 Group 2 Trading Program provisions of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to emissions of sulfur dioxide (SO_2).

(b) The provisions of subpart CCCCC of part 97 of this chapter, regarding the TR SO_2 Group 1 Trading Program, apply to sources in each of the following States: Georgia, Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.

(c) The provisions of subpart DDDDD of part 97 of this chapter, regarding the TR SO_2 Group 2 Trading Program, apply to sources in each of the following States: Alabama, Connecticut, Delaware, District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey, and South Carolina.

(d) Following promulgation of an approval by the Administrator of a State's SIP as correcting the SIP's deficiency that is the basis for this Federal Implementation Plan, the provisions of paragraph (b) and (c) of this section, as applicable, will no longer apply to sources in the State, unless the Administrator's approval of the SIP is partial or conditional.

(e) Notwithstanding the provisions of paragraph (d) of this section, if, at the time of such approval of the State's SIP, the Administrator has already allocated any TR SO_2 Group 1 allowances or any TR SO_2 Group 2 allowances (as applicable) to sources in the State for any years, the provisions of part 97 of this chapter authorizing the Administrator to complete the allocation of TR SO_2 Group 1 allowances or TR SO_2 Group 2 allowances (as applicable) for those years shall continue to apply, unless provided otherwise by such approval of the State's SIP.

Subpart I—Delaware

10. Section 52.440 is amended by adding a new paragraph (c) to read as follows:

§ 52.440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

11. Section 52.441 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.441 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart J—District of Columbia

12. Section 52.484 is amended by adding a new paragraph (c) to read as follows:

§ 52.484 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

13. Section 52.485 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.485 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart P—Indiana

14. Section 52.789 is amended by adding a new paragraph (c) to read as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

15. Section 52.790 is amended by designating the introductory text as

paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.790 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart T—Louisiana

16. Section 52.984 is amended by adding a new paragraph (c) to read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

Subpart X—Michigan

17. Section 52.1186 is amended by adding a new paragraph (c) to read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

18. Section 52.1187 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.1187 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart FF—New Jersey

19. Section 52.1584 is amended by adding a new paragraph (c) to read as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

20. Section 52.1185 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.1585 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart RR—Tennessee

21. Section 52.2240 is amended by adding a new paragraph (c) to read as follows:

§ 52.2240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X

allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

22. Section 52.2241 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.2241 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart SS—Texas

23. Section 52.2283 is amended by adding a new paragraph (c) to read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraph (a) of this section relating to NO_X annual emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances allocated for 2012 or any year thereafter.

24. Section 52.2284 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.2284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart YY—Wisconsin

25. Section 52.8587 is amended by adding a new paragraph (c) to read as follows:

§ 52.8587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

26. Section 52.8588 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.8588 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

PART 72—[AMENDED]

27. The authority citation for Part 72 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, *et seq.*

§ 72.2 [Amended]

28. Section 72.2 is amended by removing the definition of "interested person".

PART 78—[AMENDED]

29. The authority citation for Part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, *et seq.*

§ 78.1 [Amended]

30. Section 78.1 is amended by adding paragraphs (b)(13) through (b)(16) to read as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(13) Under subpart AAAAA of part 97 of this chapter,

(i) The decision on allocation of TR NO_X Annual allowances under § 97.411(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR NO_X Annual allowances under § 97.423 of this chapter.

(iii) The decision on the deduction of TR NO_X Annual allowances under §§ 97.424 and 97.425 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.427 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR NO_X Annual allowances based on the information as adjusted under § 97.428 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.435 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR NO_X Annual allowances, and the decision on the deduction of TR NO_X Annual allowances under §§ 97.441 through 97.444.

(14) Under subpart BBBBB of part 97 of this chapter, (i) The decision on allocation of TR NO_X Ozone Season

allowances under § 97.511(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR NO_X Ozone Season allowances under § 97.523 of this chapter.

(iii) The decision on the deduction of TR NO_X Ozone Season allowances under §§ 97.524 and 97.525 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.527 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR NO_X Ozone Season allowances based on the information as adjusted under § 97.528 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.535 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR NO_X Ozone Season allowances, and the decision on the deduction of TR NO_X Ozone Season allowances under §§ 97.541 through 97.544.

(15) Under subpart CCCCC of part 97 of this chapter,

(i) The decision on allocation of TR SO_2 Group 1 allowances under § 97.611(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR SO_2 Group 1 allowances under § 97.623 of this chapter.

(iii) The decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.624 and 97.625 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.627 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR SO_2 Group 1 allowances based on the information as adjusted under § 97.628 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.635 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR SO_2 Group 1 allowances, and the decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.641 through 97.644.

(16) Under subpart DDDDD of part 97 of this chapter,

(i) The decision on allocation of TR SO_2 Group 2 allowances under § 97.711(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR SO_2 Group 1 allowances under § 97.723 of this chapter.

(iii) The decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.724 and 97.725 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.727 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR SO_2 Group 1 allowances based on the information as adjusted under § 97.728 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.735 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR SO_2 Group 2 allowances, and the decision on the deduction of TR SO_2 Group 2 allowances under §§ 97.741 through 97.744.

* * * * *

§ 78.2 [Amended]

31. Section 78.2 is revised to read as follows:

§ 78.2 General.

(a) *Definitions.* (1) The terms used in this subpart with regard to a decision of the Administrator that is appealed under this section shall have the meaning as set forth in the regulations under which the Administrator made such decision and as set forth in paragraph (a)(2) of this section.

(2) *Interested person* means, with regard to a decision of the Administrator, any person who submitted comments, or testified at a public hearing, pursuant to an opportunity for comment provided by the Administrator as part of the process of making such decision, who submitted objections pursuant to an opportunity for objections provided by the Administrator as part of the process of making such decision, or who submitted his or her name to the Administrator to be placed on a list of persons interested in such decision. The Administrator may update the list of interested persons from time to time by requesting additional written indication of continued interest from the persons listed and may delete from the list the name of any person failing to respond as requested.

(b) *Availability of information.* The availability to the public of information provided to, or otherwise obtained by, the Administrator under this subpart shall be governed by part 2 of this chapter.

(c) *Computation of time.* (1) In computing any period of time prescribed or allowed under this part, except as otherwise provided, the day of the event from which the period begins to run shall not be included, and Saturdays, Sundays, and federal holidays shall be included. When the period ends on a Saturday, Sunday, or Federal holiday, the stated period shall be extended to include the next business day.

(2) Where a document is served by first class mail or commercial delivery service, but not by overnight or same-day delivery, 5 days shall be added to the time prescribed or allowed under this part for the filing of a responsive document or for otherwise responding.

§ 78.3 [Amended]

32. Section 78.3 is amended by:

a. In paragraphs (a)(1)(iii), (a)(3)(ii), (a)(4)(ii), (a)(5)(ii), (a)(6)(ii), (a)(7)(ii), (a)(8)(ii), and (a)(9)(ii), adding, after the word "person", the words "with regard to the decision".

b. Adding paragraph (a)(10);

c. In paragraph (b)(3)(i), removing the words "paragraph (a)(1) and (2)" and adding, in their place, the words "paragraph (a)(1), (2), and (10)"; and

d. Adding paragraph (d)(11) to read as follows:

§ 78.3 Petition for administrative review and request or evidentiary hearing.

(a) * * *

(10) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AAAAA, BBBBB, CCCCC, and DDDDD of part 97 of this chapter:

(i) The designated representative for a unit or source, or the authorized account representative for any Allowance Management System account, covered by the decision; or

(ii) Any interested person with regard to the decision.

* * * * *

(d) * * *

(11) Any provision or requirement of subparts AAAAA, BBBBB, CCCCC, or DDDDD of part 97 of this chapter, including the standard requirements under § 97.406, § 97.506, § 97.606, or § 97.706 of this chapter and any emission monitoring or reporting requirements.

§ 78.4 [Amended]

33. Section 78.4 is amended by:

a. Revising paragraph (a) by:

i. Removing the first, second, third, fourth, fifth, and last sentences;

ii. In the sixth and seventh sentences, removing the words "interest in" and adding, in their place, the words "ownership interest with respect to"; and

iii. Redesignating the paragraph as paragraph (a)(1)(iii); and

b. Adding paragraphs (a)(1) introductory text, (a)(1)(i), (a)(1)(ii) and (a)(2) to read as follows:

§ 78.4 Filings.

(a)(1) All original filings made under this part shall be signed by the person making the filing or by an attorney or authorized representative, in accordance with the following requirements:

(i) Any filings on behalf of owners and operators of a affected unit or affected source, TR NO_X Annual unit or TR NO_X Annual source, TR NO_X Ozone Season unit or TR NO_X Ozone Season source, TR SO_2 Group 1 unit or TR SO_2 Group 1 source, TR SO_2 Group 2 unit or TR SO_2 Group 2 source, or a unit for which a TR opt-in application is submitted and not withdrawn shall be signed by the designated representative. Any filing on behalf of persons with an ownership interest with respect to allowances, TR NO_X Annual allowances, TR NO_X Ozone Season allowances, TR SO_2 Group 1 allowances, or TR SO_2 Group 2 allowances in a general account shall be signed by the authorized account representative.

(ii) Any filings on behalf of owners and operators of a NO_X Budget unit or NO_X Budget source shall be signed by the NO_X authorized account representative. Any filing on behalf of persons with an ownership interest with respect to NO_X allowances in a general account shall be signed by the NO_X authorized account representative.

* * * * *

(2) The name, address, e-mail address (if any), telephone number, and facsimile number (if any) of the person making the filing shall be provided with the filing.

* * * * *

PART 97—[AMENDED]

34. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

35. Part 97 is amended by adding subpart AAAAA to read as follows:

Subpart AAAAA TR NO_X Annual Trading Program

Sec.

Subpart AAAAA—TR NO_X Annual Trading Program

§ 97.401 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO_X Annual Trading Program, under section 110 of the Clean Air Act and § 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.402 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR NO_X Annual allowances, the determination by the Administrator of the amount of such TR NO_X Annual allowances to be initially credited to a TR NO_X Annual source or a new unit set-aside.

Allowable NO_X emission rate means, with regard to a unit, the NO_X emission rate limit that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR NO_X Annual allowances under the TR NO_X Annual Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR NO_X Annual allowances and data related to NO_X emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NO_X Annual allowances.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NO_X Annual allowance transfer must be submitted for recordation in a TR NO_X

Annual source's compliance account in order to be available for use in complying with the source's TR NO_X Annual emissions limitation for such control period in accordance with § 97.424.

Alternate designated representative means, for a TR NO_X Annual source and each TR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NO_X Annual Trading Program. If the TR NO_X Annual source is also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.502, § 97.602, or § 97.702 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NO_X Annual allowances held in the general account and, with regard to a TR NO_X Annual source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil-or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.405.

(i) For a unit that is a TR NO_X Annual unit under § 97.404 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR NO_X Annual unit under § 97.404 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the

replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.405, for a unit that is not a TR NO_X Annual unit under § 97.404 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR NO_X Annual unit under § 97.404.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NO_X Annual source under this subpart, in which any TR NO_X Annual allowance allocations for the TR NO_X Annual units at the source are recorded and in which are held any TR NO_X Annual allowances available for use for a control period in complying with the source's TR NO_X Annual emissions limitation in accordance with § 97.424 and the TR NO_X Annual assurance provisions in accordance with § 97.425.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.430 through 97.435. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.406(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR NO_X Annual source and each TR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NO_X Annual Trading Program. If the TR NO_X Annual source is also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.502, § 97.602, or § 97.702 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of NO_X emitted from the TR NO_X Annual units at a TR NO_X Annual source during a control period that exceeds the TR NO_X Annual emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.404(b)(2)(i)(B), 97.404(b)(2)(ii)(B), and 97.404(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any

recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR NO_X Annual unit means a unit that was not a TR NO_X Annual unit when it began operating but that thereafter becomes a TR NO_X Annual unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR NO_X Annual unit or a TR NO_X Annual source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR NO_X Annual source or a TR NO_X Annual unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR NO_X Annual unit at the source or the TR NO_X Annual unit;

(2) Any holder of a leasehold interest in a TR NO_X Annual unit at the source or the TR NO_X Annual unit, provided that, unless expressly provided for in a leasehold agreement, "owner" shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR NO_X Annual unit;

(3) Any purchaser of power from a TR NO_X Annual unit at the source or the TR NO_X Annual unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR NO_X Annual assurance provisions in §§ 97.406(c)(2) and 97.425, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR NO_X Annual units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.406(c)(2)(iii)(A) and not as described in § 97.406(c)(2)(iii)(B), the owner's share of the State NO_X Annual trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.406(c)(2)(iii)(B), the owner's share of the State NO_X Annual trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period, the total tonnage of NO_X emissions during such control period from all of the owner's TR NO_X Annual units in the State;

(2) With regard to a State NO_X Annual trading budget with a one-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Annual allowances allocated for such control period to all of the owner's TR NO_X Annual units in the State, multiplied by the sum of the State NO_X Annual trading budget under § 97.410(a) and the State's one-year variability limit under § 97.410(b) and divided by such State NO_X Annual trading budget;

(3) With regard to a State NO_X Annual trading budget with a three-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Annual allowances allocated for such control period to all of the owner's TR NO_X Annual units in the State, multiplied by the sum of the State NO_X Annual trading budget under § 97.410(a) and the State's three-year variability limit under § 97.410(b) and divided by such State NO_X Annual trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of NO_X emissions and of TR NO_X Annual allowances allocated for a control period, with regard to such unit, used in determining each owner's share

shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's NO_X emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of December 31 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which NO_X mass emissions are reported for a control period for a year, the amount of tonnage of each unit's NO_X emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of NO_X emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be *de minimis*; or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.435; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR NO_X Annual allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NO_X Annual allowances for such control period equal to the lesser of—

(i) The unit's allowable NO_X emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.84 (if the unit is a coal-fired boiler), 0.15 (if the unit is a simple combustion turbine), or 0.66 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's NO_X emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR NO_X Annual allowances, the moving of TR NO_X Annual allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NO_X Annual allowance, the unique identification number assigned to each TR NO_X Annual allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source," "stationary source," or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR NO_X Annual Trading Program pursuant to § 52.37(a) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR NO_X Annual Program.

TR NO_X Annual allowance deduction or deduct TR NO_X Annual allowances means the permanent withdrawal of TR NO_X Annual allowances by the Administrator from a compliance account, *e.g.*, in order to account for compliance with the TR NO_X Annual emissions limitation or assurance provisions.

TR NO_X Annual allowances held or hold TR NO_X Annual allowances means the TR NO_X Annual allowances treated

as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO_X Annual allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO_X Annual allowance transfer in accordance with this subpart.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Annual emissions limitation means, for a TR NO_X Annual source, the tonnage of NO_X emissions authorized in a control period by the TR NO_X Annual allowances available for deduction for the source under § 97.424(a) for such control period.

TR NO_X Annual source means a source that includes one or more TR NO_X Annual units.

TR NO_X Annual unit means a unit that is subject to the TR NO_X Annual Trading Program under § 97.404.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart BBBBB of this part and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart CCCCC of this part and 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart DDDDD of this part and 52.38(c) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.403 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.404 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR NO_X Annual units, and any source that includes one or more such units shall be a TR NO_X Annual source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR NO_X Annual unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR NO_X Annual unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR NO_X Annual unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR NO_X Annual unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Annual unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Annual unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Annual Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Annual Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.405 Retired unit exemption.

(a)(1) Any TR NO_X Annual unit that is permanently retired and is not a TR NO_X Annual opt-in unit shall be exempt from § 97.406(b) and (c)(1), § 97.424, and §§ 97.430 through 97.435.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NO_X Annual unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR NO_X Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.406 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.413 through 97.418.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.430 through 97.435.

(2) The emissions data determined in accordance with §§ 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under §§ 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *NO_X emissions requirements.* (1) TR NO_X Annual emissions limitation. (i) As of the allowance transfer deadline for a control period, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under § 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(ii) If a TR NO_X Annual source emits NO_X during any control period in excess of the TR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under § 97.424(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR NO_X Annual assurance provisions. (i) If the total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such NO_X emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.425(b)(4)(ii), TR NO_X Annual allowances available for deduction for such control period under § 97.425(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.425(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such NO_X emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such NO_X emissions exceeds that owner's assurance level; and

(B) The amount by which total NO_X emissions for all TR NO_X Annual units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR NO_X Annual allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) The total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of NO_X emissions exceeds the sum, for such control period, of the State NO_X Annual trading budget and the State's one-year variability limit under § 97.410(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of NO_X emissions and the total amounts of NO_X emissions from all TR NO_X Annual units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State NO_X Annual trading budget and the State's three-year variability limit under § 97.410(b);

(C) Provided that the amount by which such total amount of NO_X emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period exceeds the State assurance level or if an owner's share of total NO_X emissions from the TR NO_X Annual units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR NO_X Annual allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Annual allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR NO_X Annual unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.430(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.430(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR NO_X Annual allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR NO_X Annual allowance was allocated.

(5) *Allowance Management System requirements.* Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X in accordance with the TR NO_X Annual Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR NO_X Annual allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.430 through 97.435 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time

before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.416 for the designated representative for the source and each TR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 97.416 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Annual Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, including any submissions required for compliance with the TR NO_X Annual assurance provisions. This requirement does not change, create an exemption from, or or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR NO_X Annual Trading Program or exemption under § 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.407 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NO_X Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR NO_X Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR NO_X Annual Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.408 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NO_X Annual Trading Program are set forth in part 78 of this chapter.

§ 97.409 [Reserved]

§ 97.410 State NO_X Annual trading budgets, new-unit set-asides, and variability limits.

(a) The State NO_X Annual trading budgets and new-unit set-asides for allocations of TR NO_X Annual allowances for the control periods in 2012 and thereafter are as follows:

State	NO_X annual trading budget (tons) *	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Alabama	69,169	2,075
Connecticut	2,775	83
Delaware	6,206	186
District of Columbia	170	5
Florida	120,001	3,600
Georgia	73,801	2,214
Illinois	56,040	1,681
Indiana	115,687	3,471
Iowa	46,068	1,382
Kansas	51,321	1,540
Kentucky	74,117	2,224
Louisiana	43,946	1,318
Maryland	17,044	511
Massachusetts	5,960	179
Michigan	64,932	1,948
Minnesota	41,322	1,240
Missouri	57,681	1,730
Nebraska	43,228	1,297
New Jersey	11,826	355
New York	23,341	700
North Carolina	51,800	1,554
Ohio	97,313	2,919
Pennsylvania	113,903	3,417
South Carolina	33,882	1,016
Tennessee	28,362	851
Virginia	29,581	887
West Virginia	51,990	1,560
Wisconsin	44,846	1,345

State	NO_X annual trading budget (tons) *	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Total	1,376,312	41,288

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State NO_X Annual trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Alabama	6,917	3,993
Connecticut	5,000	2,887
Delaware	5,000	2,887
District of Columbia	5,000	2,887
Florida	12,000	6,928
Georgia	7,380	4,261
Illinois	5,604	3,235
Indiana	11,569	6,679
Iowa	5,000	2,887
Kansas	5,132	2,963
Kentucky	7,412	4,279
Louisiana	5,000	2,887
Maryland	5,000	2,887
Massachusetts	5,000	2,887
Michigan	6,493	3,749
Minnesota	5,000	2,887
Missouri	5,768	3,330
Nebraska	5,000	2,887
New Jersey	5,000	2,887
New York	5,000	2,887
North Carolina	5,180	2,991
Ohio	9,731	5,618
Pennsylvania	11,390	6,576
South Carolina	5,000	2,887
Tennessee	5,000	2,887
Virginia	5,000	2,887
West Virginia	5,199	3,002
Wisconsin	5,000	2,887

§ 97.411 Timing requirements for TR NO_X Annual allowance allocations.

(a) *Existing units.* (1) TR NO_X Annual allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR NO_X Annual unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR NO_X Annual unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR NO_X Annual allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR NO_X Annual allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR NO_X Annual allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO_X Annual allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By July 1, 2012 and July 1 of each year thereafter, the Administrator will calculate the TR NO_X Annual allowance allocation for each TR NO_X Annual unit, in accordance with § 97.412, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.412 and §§ 97.406(b)(2) and 97.430 through 97.435.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By September 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR NO_X Annual units.* For each control period in 2012 and thereafter, if the Administrator determines that TR NO_X Annual allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR NO_X Annual unit under § 97.404 as of January 1, 2012 or whose deadline for meeting monitor certification requirements under § 97.430(b)(1) and (2) is after January 1, 2012 or if the Administrator determines that TR NO_X Annual allowances were allocated under paragraph (b) of this section and § 97.412 for the control period to a recipient that is not actually a TR NO_X Annual unit under § 97.404 as of January 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR NO_X Annual allowances under § 97.421.

(2) If the Administrator already recorded such TR NO_X Annual allowances under § 97.421 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.424(b) for such control period, then the Administrator will deduct from the account in which such TR NO_X Annual allowances were recorded an amount of TR NO_X Annual allowances allocated for the same or a prior control period equal to the amount of such already recorded TR NO_X Annual allowances. The authorized account representative shall ensure that there are sufficient TR NO_X Annual allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR NO_X Annual allowances under § 97.421 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.424(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR NO_X Annual allowances.

(4) The Administrator will transfer the TR NO_X Annual allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, if such notice has been promulgated, in the next year.

§ 97.412 TR NO_X Annual allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR NO_X Annual allowances to TR NO_X Annual units in a State that are not listed in appendix A to this subpart, to TR NO_X Annual units that are so listed and whose allocation of NO_X Annual allowances for such control period is covered by § 97.411(c)(1) or (2), and to TR NO_X Annual units that are so listed and, pursuant to § 97.411(a)(2), are not allocated TR NO_X Annual allowances for such control period but operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR NO_X Annual allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.410(a). Each new unit set-aside will be allocated additional TR NO_X Annual allowances in accordance with § 97.411(a)(2) and (c)(4).

(2) The designated representative of such TR NO_X Annual unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR NO_X Annual allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR NO_X Annual unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before May 1 of the first control period for which TR NO_X Annual allowances are sought and after the date on which the TR NO_X Annual unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR NO_X Annual allowances in an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(3) The Administrator will review each TR NO_X Annual allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR NO_X Annual allowances for each control period pursuant to an accepted request as follows:

(i) After May 1 of such control period, the Administrator will determine the sum of the TR NO_X Annual allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR NO_X Annual allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR NO_X Annual allowances requested to each TR NO_X Annual unit covered by an accepted allowance allocation request.

(iii) If the amount of TR NO_X Annual allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR NO_X Annual unit covered by an accepted allowance allocation request the amount of the TR NO_X Annual allowances requested, multiplied by the amount of TR NO_X Annual allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.411(b), each designated representative that submitted an allowance allocation request of the amount of TR NO_X Annual allowances (if any) allocated for such control period to the TR NO_X Annual unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR NO_X Annual allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR

NO_X Annual unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR NO_X Annual allowances for such control period in accordance with § 97.411(a)(2), an amount of TR NO_X Annual allowances equal to the following: The total amount of such remaining unallocated TR NO_X Annual allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.411(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Annual trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.413 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.415, each TR NO_X Annual source, including all TR NO_X Annual units at the source, shall have one and only one designated representative, with regard to all matters under the TR NO_X Annual Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Annual units at the source and shall act in accordance with the certification statement in § 97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.416:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR NO_X Annual unit at the source in all matters pertaining to the TR NO_X Annual Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR NO_X Annual unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.415, each TR NO_X Annual source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Annual units at the source and shall act in accordance with the certification statement in § 97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.416:

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO_X Annual unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.402, and §§ 97.414 through 97.418, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.414 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.418 concerning delegation of authority to make submissions, each submission under the TR NO_X Annual Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NO_X Annual source and TR NO_X Annual unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a TR NO_X Annual source or a TR NO_X Annual unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.418.

§ 97.415 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NO_X Annual source and the TR NO_X Annual units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NO_X Annual source and the TR NO_X Annual units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR NO_X Annual source or a TR NO_X Annual unit is not included in the list of owners and operators in the certificate of representation under § 97.416, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NO_X Annual source or a TR NO_X Annual unit, including the addition of a new

owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.416 amending the list of owners and operators to include the change.

§ 97.416 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NO_X Annual source, and each TR NO_X Annual unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NO_X Annual source and of each TR NO_X Annual unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NO_X Annual unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Annual Trading Program on behalf of the owners and operators of the source and of each TR NO_X Annual unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR NO_X Annual unit, or where a utility or industrial customer purchases power from a TR NO_X Annual unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR NO_X Annual unit at the source; and TR NO_X Annual allowances and proceeds of transactions involving TR NO_X Annual allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR NO_X Annual allowances by contract, TR NO_X Annual allowances and proceeds of transactions involving TR NO_X Annual allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.417 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.416 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.416 is received by the Administrator.

(b) Except as provided in § 97.415(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NO_X Annual Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NO_X Annual allowance transfers.

§ 97.418 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.418 is terminated."

(d) A notice of delegation submitted under paragraph (c) of this section shall

be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.419 [Reserved]

§ 97.420 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.416, the Administrator will establish a compliance account for the TR NO_X Annual source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.*

(i) Any person may apply to open a general account, for the purpose of holding and transferring TR NO_X Annual allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NO_X Annual allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR NO_X Annual allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NO_X Annual allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Annual Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator: (A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO_X Annual allowances held in the general account in all matters pertaining to the TR NO_X Annual Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO_X Annual allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO_X Annual allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO_X Annual allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or

any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR NO_X Annual allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO_X Annual allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO_X Annual allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Annual allowances in the general account, including the addition of a new person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR NO_X Annual allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NO_X Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NO_X Annual allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.420(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated

representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR NO_X Annual allowance transfer under § 97.422 for any TR NO_X Annual allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR NO_X Annual allowance transfers to or from the account for a 12-month period or longer and does not contain any TR NO_X Annual allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted TR NO_X Annual allowance transfer under § 97.422 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR NO_X Annual allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.414(a) and 97.418 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.421 Recordation of TR NO_X Annual allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated for the TR NO_X Annual units at the source in accordance with §§ 97.411(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated for the TR NO_X Annual units at the source in accordance with § 97.411(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By September 1, 2012 and September 1 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated for the TR NO_X Annual units at the source in accordance with § 97.412 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR NO_X Annual allowances for a TR NO_X Annual unit in a compliance account, the Administrator will assign each TR NO_X Annual allowance a unique identification number that will include digits identifying the year of the control period for which the TR NO_X Annual allowance is allocated.

§ 97.422 Submission of TR NO_X Annual allowance transfers.

(a) An authorized account representative seeking recordation of a TR NO_X Annual allowance transfer shall submit the transfer to the Administrator.

(b) A TR NO_X Annual allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR NO_X Annual allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR NO_X Annual allowance identified by serial number in the transfer.

§ 97.423 Recordation of TR NO_X Annual allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NO_X Annual allowance transfer, the Administrator will record a TR NO_X Annual allowance transfer by moving each TR NO_X Annual allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.422.

(b)(1) A TR NO_X Annual allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NO_X Annual allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.424 for the control period immediately before such allowance transfer deadline.

(2) A TR NO_X Annual allowance transfer that is submitted for recordation after the deadline for holding TR NO_X Annual allowances described in § 97.425(b)(5) and that includes any TR NO_X Annual allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.425 for the control period immediately before the year of such deadline.

(c) Where a TR NO_X Annual allowance transfer is not correctly submitted under § 97.422, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR NO_X Annual allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR NO_X Annual allowance transfer that is not correctly submitted under § 97.422, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.424 Compliance with TR NO_X Annual emissions limitation.

(a) *Availability for deduction for compliance.* TR NO_X Annual allowances are available to be deducted for compliance with a source's TR NO_X Annual emissions limitation for a control period in a given year only if the TR NO_X Annual allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.423, of TR NO_X Annual allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR NO_X Annual allowances available under paragraph

(a) of this section in order to determine whether the source meets the TR NO_X Annual emissions limitation for such control period, as follows:

(1) Until the amount of TR NO_X Annual allowances deducted equals the number of tons of total NO_X emissions from all TR NO_X Annual units at the source for such control period; or

(2) If there are insufficient TR NO_X Annual allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NO_X Annual allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR NO_X Annual allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR NO_X Annual allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NO_X Annual source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Annual allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Annual allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Annual allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Annual allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NO_X Annual source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR NO_X Annual allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.425 Compliance with TR NO_X Annual assurance provisions.

(a) *Availability for deduction.* TR NO_X Annual allowances are available to be deducted for compliance with the TR NO_X Annual assurance provisions for a control period in a given year by an owner of one or more TR NO_X Annual units in a State only if the TR NO_X Annual allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance with paragraph (b)(4)(ii) of this section, of one of the owner's TR NO_X Annual sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR NO_X Annual allowances available under paragraph (a) of this section for compliance with the TR NO_X Annual assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of NO_X emissions from all TR NO_X Annual units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.406(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions for each TR NO_X Annual unit and of the amounts described in §§ 97.406(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR NO_X Annual unit and each State for the control period in the year involved are in accordance with § 97.406(c)(2)(iii) and §§ 97.406(b) and 97.430 through 97.435.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By August 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR NO_X Annual sources with total NO_X emissions exceeding the State assurance level for a control period, as described in § 97.406(c)(2)(iii):

(i) By August 15 immediately after the promulgation of such notice, the designated representative of each TR NO_X Annual source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR NO_X Annual unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.402, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR NO_X Annual unit at the source that operates during, but is allocated no TR NO_X Annual allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable NO_X emission rate for such control period.

(ii) By September 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR NO_X Annual units in the State and for the control period in the year involved, each owner's share of the total NO_X emissions from all TR NO_X Annual units in the State, each owner's assurance level, and the amount (if any) of TR NO_X Annual allowances that each owner must hold in accordance with the calculation formula in § 97.406(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability

required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the NO_X emissions for the relevant TR NO_X Annual units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.402, and the calculation formula in § 97.406(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section. By November 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By December 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR NO_X Annual units in a State and as being required to hold TR NO_X Annual allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR NO_X Annual allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of December 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR NO_X Annual allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if December 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After December 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.423, of TR NO_X Annual allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR NO_X Annual allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR NO_X Annual allowances deducted equals the amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR NO_X Annual allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR NO_X Annual allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR NO_X Annual allowances that each owner is required to hold in accordance with § 97.406(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Annual allowances that owners are required to hold in accordance with the calculation formula in § 97.406(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Annual allowances that owners are required to hold in accordance with the calculation formula in § 97.406(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR NO_X Annual allowances that an owner is required to hold for the control period in the year involved with regard to the State involved-

(A) Where the amount of TR NO_X Annual allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR NO_X Annual allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR NO_X Annual allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the

year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR NO_X Annual allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR NO_X Annual allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance account) for the control period in the year involved.

(C) Each TR NO_X Annual allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements under the TR NO_X Annual assurance provisions for a control period in a given year must be a TR NO_X Annual allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR NO_X Annual allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR NO_X Annual allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Annual allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Annual allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Annual allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Annual allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.426 Banking.

(a) A TR NO_X Annual allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR NO_X Annual allowance that is held in a compliance account or a general account will remain in such account unless and until the TR NO_X Annual allowance is deducted or transferred under § 97.411(c), § 97.423, § 97.424, § 97.425, 97.427, 97.428, 97.442, or 97.443.

§ 97.427 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.428 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO_X Annual Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO_X Annual allowances from or transfer TR NO_X Annual allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.429 [Reserved]

§ 97.430 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO_X Annual unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.402 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR NO_X Annual unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.402, and the term "newly affected unit" shall be deemed to mean "newly affected TR NO_X Annual unit". The owner or operator of a unit that is not a TR NO_X Annual unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR NO_X Annual unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR NO_X Annual unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 97.431 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NO_X Annual unit that commences commercial operation before July 1, 2011, January 1, 2012;

(2) For the owner or operator of a TR NO_X Annual unit that commences commercial operation on or after July 1, 2011, the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation;

(3) For the owner or operator of a TR NO_X Annual unit for which construction of a new stack or flue or installation of add-on NO_X emission

controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls;

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.441(c); and

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a TR NO_X Annual opt-in unit, by the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program as provided in § 97.441(h).

(c) *Reporting data.* The owner or operator of a TR NO_X Annual unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR NO_X Annual unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.435.

(2) No owner or operator of a TR NO_X Annual unit shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR NO_X Annual unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR NO_X Annual unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.405 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.431(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR NO_X Annual unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.431 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NO_X Annual unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.430(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.430(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.435 to determine whether the approval applies under the TR NO_X Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NO_X Annual unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.430(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.430(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.430(b).

In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.430(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete

replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 97.430(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.430(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.433.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NO_X Annual Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR NO_X Annual Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period specified in paragraph (d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.432(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(*5*) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such

a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.432 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.431 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.431 for each disapproved monitoring system.

§ 97.433 Notifications concerning monitoring.

The designated representative of a TR NO_X Annual unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.434 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.414(a).

(b) *Monitoring plans.* The owner or operator of a TR NO_X Annual unit shall comply with requirements of § 75.73(c) and (e) of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.431, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the NO_X mass emissions data and heat input data for the TR NO_X Annual unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.430(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.441(c); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a TR NO_X Annual opt-in unit, the calendar quarter corresponding to the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program as provided in § 97.441(h).

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(3) For TR NO_X Annual units that are also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the

unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions.

§ 97.435 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NO_X Annual unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.430 through 97.434 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.402.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.440 General requirements for TR NO_X Annual opt-in units.

(a) A TR NO_X Annual opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR NO_X Annual unit under § 97.404;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR NO_X Annual opt-in unit shall be deemed to be a TR NO_X Annual unit for purposes of applying this subpart, except for §§ 97.405, 97.411, and 97.412.

(c) Solely for purposes of applying the requirements of §§ 97.413 through 97.418 and §§ 97.430 through 97.435, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.442 shall be deemed to be a TR NO_X Annual unit.

(d) Any TR NO_X Annual opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.442, located at the same source as one or more TR NO_X Annual units shall have the same designated representative and alternate designated representative as such TR NO_X Annual units.

§ 97.441 Opt-in process.

A unit meeting the requirements for a TR NO_X Annual opt-in unit in § 97.440(a) may become a TR NO_X Annual opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.442(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR NO_X Annual unit under § 97.404;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.430 through 97.435;

(4) A statement that the unit, if approved to become a TR NO_X Annual unit under paragraph (g) of this section, may withdraw from the TR NO_X Annual Trading Program only in accordance with § 97.442;

(5) A statement that the unit, if approved to become a TR NO_X Annual unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.443;

(6) A complete certificate of representation under § 97.416 consistent with § 97.440, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) Interim review of monitoring plan. The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.430 through 97.435. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) Monitoring and reporting. (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the NO_X emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.430 through 97.435, starting on the date of certification of the necessary monitoring systems under §§ 97.430 through 97.435 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR NO_X Annual Trading Program in accordance with § 97.442.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR NO_X Annual Trading Program under paragraph (h) of this section, during which period monitoring system availability must not

be less than 98 percent under §§ 97.430 through 97.435 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emission rate and the heat input of the unit are monitored and reported in accordance with §§ 97.430 through 97.435 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.430 through 97.435 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR NO_X Annual Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's NO_X emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's NO_X emission rate (in lb/mmBtu) for such control period;

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods during which the unit has add-on NO_X emission controls.

(g) *Review of TR opt-in application.*

(1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR NO_X Annual opt-in unit in § 97.440, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approval will state the unit's baseline heat input and baseline NO_X emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR NO_X Annual opt-in unit in § 97.440, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) *Date of entry into TR NO_X Annual Trading Program.* A unit for which a TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR NO_X Annual opt-in unit, and a TR NO_X Annual unit, effective as of the later of January 1, 2012 or January 1 of the first control period during which such approval is issued.

§ 97.442 Withdrawal of TR NO_X Annual opt-in unit from TR NO_X Annual Trading Program.

A TR NO_X Annual opt-in unit may withdraw from the TR NO_X Annual Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR NO_X Annual opt-in unit from the TR NO_X Annual Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of the unit's entry into the TR NO_X Annual Trading Program under § 97.441(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR NO_X Annual opt-in unit covered by the request to withdraw may withdraw from the TR NO_X Annual Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR NO_X Annual opt-in unit must meet the requirement to hold TR NO_X Annual allowances under §§ 97.424 and 97.425 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR NO_X Annual opt-in unit TR NO_X Annual allowances equal in amount to and allocated for the same or a prior control period as any TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under § 97.444 for any control period after the date on which the withdrawal is to be effective. If there are no other TR NO_X Annual units at the source, the Administrator will close the compliance account, and the owners and operators of the TR NO_X Annual opt-in unit may submit a TR NO_X Annual allowance transfer for any remaining TR NO_X Annual allowances to another Allowance Management System account in accordance with §§ 97.422 and 97.423.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR NO_X Annual allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on December 31 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR NO_X Annual opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR NO_X

Annual Trading Program concerning any control periods for which the unit is a TR NO_X Annual opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR NO_X Annual opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR NO_X Annual Trading Program.* Once a TR NO_X Annual opt-in unit withdraws from the TR NO_X Annual Trading Program, the designated representative may not submit another opt-in application under § 97.441 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.443 Change in regulatory status.

(a) *Notification.* If a TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR NO_X Annual opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, the Administrator will deduct, from the compliance account of the source that includes the TR NO_X Annual opt-in unit that becomes a TR NO_X Annual unit under § 97.404, TR NO_X Annual allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under § 97.444 for any control period starting after the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404; and

(ii) If the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404 is not December 31, the TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under § 97.444 for the control period that includes the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR NO_X Annual opt-in unit that becomes a TR NO_X Annual unit under § 97.404 contains the TR NO_X Annual allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, the TR NO_X Annual opt-in unit will be allocated TR NO_X Annual allowances in accordance with § 97.412.

(ii) If the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404 is not December 31, the following amount of TR NO_X Annual allowances will be allocated to the TR NO_X Annual opt-in unit (as a TR NO_X Annual unit) in accordance with § 97.412 for the control period that includes the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404:

(A) The amount of TR NO_X Annual allowances otherwise allocated to the TR NO_X Annual opt-in unit (as a TR NO_X Annual unit) in accordance with § 97.412 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, divided by the total number of days in the control period; and (C) Rounded to the nearest allowance.

§ 97.444 TR NO_X Annual allowance allocations to TR NO_X Annual opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.441(g), the Administrator will issue TR NO_X Annual allowances and allocate them to the unit for the control period in which the unit enters the TR NO_X Annual Trading Program under § 97.441(h), in accordance with paragraph (b) of this section.

(2) By no later than October 31 of the control period after the control period in which a TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program under § 97.441(h) and October 31 of each year thereafter, the Administrator will issue TR NO_X Annual allowances and allocate them to the TR NO_X Annual opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR NO_X Annual opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR NO_X Annual opt-in unit is to be allocated TR NO_X Annual allowances, the Administrator will issue and allocate TR NO_X Annual allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR NO_X Annual allowance allocation will be the lesser of:

(i) The TR NO_X Annual opt-in unit's baseline heat input determined under § 97.441(g); or

(ii) The TR NO_X Annual opt-in unit's heat input, as determined in accordance with §§ 97.430 through 97.435, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program under § 97.441(h).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating TR NO_X Annual allowance allocations will be the lesser of:

(i) The TR NO_X Annual opt-in unit's baseline NO_X emission rate (in lb/mmBtu) determined under § 97.441(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the TR NO_X Annual opt-in unit at any time during the control period for which TR NO_X Annual allowances are to be allocated.

(3) The Administrator will issue TR NO_X Annual allowances and allocate them to the TR NO_X Annual opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR NO_X Annual opt-in unit, the TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period after the control period in which a TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program under § 97.441(h) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR NO_X Annual opt-in unit, the TR NO_X Annual allowances allocated to the TR NO_X

Annual opt-in unit under paragraph (a)(2) of this section.

36. Part 97 is amended by adding subpart BBBBB to read as follows:

Subpart BBBBB—TR NO_X Ozone Season Trading Program

Subpart BBBBB—TR NO_X Ozone Season Trading Program

§ 97.501 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO_X Ozone Season Trading Program, under section 110 of the Clean Air Act and § 52.37(b) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.502 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR NO_X Ozone Season allowances, the determination by the Administrator of the amount of such TR NO_X Ozone Season allowances to be initially credited to a TR NO_X Ozone Season source or a new unit set-aside.

Allowable NO_X emission rate means, with regard to a unit, the NO_X emission rate limit that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR NO_X Ozone Season allowances under the TR NO_X Ozone Season Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR NO_X Ozone Season allowances and data related to NO_X emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NO_X Ozone Season allowances.

Allowance transfer deadline means, for a control period, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NO_X Ozone Season allowance transfer must be submitted for recordation in a TR NO_X Ozone Season source's compliance account in order to be available for use in complying with the source's TR NO_X Ozone Season emissions limitation for such control period in accordance with § 97.524.

Alternate designated representative means, for a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NO_X Ozone Season Trading Program. If the TR NO_X Ozone Season source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.402, § 97.602, or § 97.702 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NO_X Ozone Season allowances held in the general account and, with regard to a TR NO_X Ozone Season source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.505.

(i) For a unit that is a TR NO_X Ozone Season unit under § 97.504 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR NO_X Ozone Season unit under § 97.504 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.505, for a unit that is not a TR NO_X Ozone Season unit under § 97.504 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR NO_X Ozone Season unit under § 97.504.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source)

after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NO_X Ozone Season source under this subpart, in which any TR NO_X Ozone Season allowance allocations for the TR NO_X Ozone Season units at the source are recorded and in which are held any TR NO_X Ozone Season allowances available for use for a control period in complying with the source's TR NO_X Ozone Season emissions limitation in accordance with § 97.524 and the TR NO_X Ozone Season assurance provisions in accordance with § 97.525.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.530 through 97.535. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting May 1 of a calendar year, except as provided in § 97.506(c)(3), and ending on September 30 of the same year, inclusive.

Designated representative means, for a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NO_X Ozone Season Trading Program. If the TR NO_X Ozone Season source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.402, § 97.602, or § 97.702 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of NO_X emitted from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source during a control period that exceeds the TR NO_X Ozone Season emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.504(b)(2)(i)(B), 97.504(b)(2)(ii)(B), and 97.504(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR NO_X Ozone Season unit means a unit that was not a TR NO_X Ozone Season unit when it began operating but that thereafter becomes a TR NO_X Ozone Season unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR NO_X Ozone Season unit or a TR NO_X Ozone Season source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit;

(2) Any holder of a leasehold interest in a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit, provided that, unless expressly provided for in a leasehold agreement, "owner" shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR NO_X Ozone Season unit;

(3) Any purchaser of power from a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR NO_X Ozone Season assurance provisions in §§ 97.506(c)(2) and 97.525, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR NO_X Ozone Season units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.506(c)(2)(iii)(A) and not as described in § 97.506(c)(2)(iii)(B), the owner's share of the State NO_X Ozone Season trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.506(c)(2)(iii)(B), the owner's share of the State NO_X Ozone Season trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period, the total tonnage of NO_X emissions during such control period from all of the owner's TR NO_X Ozone Season units in the State;

(2) With regard to a State NO_X Ozone Season trading budget with a one-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Ozone Season allowances allocated for such control period to all of the owner's TR NO_X Ozone Season units in the State, multiplied by the sum of the State NO_X Ozone Season trading budget under § 97.510(a) and the State's one-year variability limit under § 97.510(b) and divided by such State NO_X Ozone Season trading budget;

(3) With regard to a State NO_X Ozone Season trading budget with a three-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Ozone Season allowances allocated for such control period to all of the owner's TR NO_X Ozone Season units in the State, multiplied by the sum of the State NO_X Ozone Season trading budget under § 97.510(a) and the State's three-year variability limit under § 97.510(b) and divided by such State NO_X Ozone Season trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of NO_X emissions and of TR NO_X Ozone Season allowances allocated for a control period, with regard to such unit, used in determining each owner's share shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's NO_X emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of September 30 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which NO_X mass emissions are reported for a control period for a year, the amount of tonnage of each unit's NO_X emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of NO_X emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be de minimis; or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.535; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR NO_X Ozone Season allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NO_X Ozone Season allowances for such control period equal to the lesser of—

(i) The unit's allowable NO_X emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.89 (if the unit is a coal-fired boiler), 0.22 (if the unit is a simple combustion turbine), or 0.72 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 3,672 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's NO_X emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR NO_X Ozone Season allowances, the moving of TR NO_X Ozone Season allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NO_X Ozone Season allowance, the unique identification number assigned to each TR NO_X Ozone Season allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source", "stationary source", or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR NO_X Ozone Season Trading Program pursuant to § 52.37(b) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55 (W + 9H)$$

Where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart AAAAA of this part and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR NO_X Ozone Season Program.

TR NO_X Ozone Season allowance deduction or deduct TR NO_X Ozone Season allowances means the permanent withdrawal of TR NO_X Ozone Season allowances by the Administrator from a compliance account, e.g., in order to account for compliance with the TR NO_X Ozone Season emissions limitation or assurance provisions.

TR NO_X Ozone Season allowances held or hold TR NO_X Ozone Season allowances means the TR NO_X Ozone Season allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO_X Ozone Season allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO_X Ozone Season allowance transfer in accordance with this subpart.

TR NO_X Ozone Season emissions limitation means, for a TR NO_X Ozone Season source, the tonnage of NO_X emissions authorized in a control period by the TR NO_X Ozone Season allowances available for deduction for the source under § 97.524(a) for such control period.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR NO_X Ozone Season source means a source that includes one or more TR NO_X Ozone Season units.

TR NO_X Ozone Season unit means a unit that is subject to the TR NO_X Ozone Season Trading Program under § 97.504.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart CCCCC of this part and 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart DDDDD of this part and 52.38(c) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.503 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.504 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR NO_X Ozone Season units, and any source that includes one or more such units shall be a TR NO_X Ozone Season source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR NO_X Ozone Season unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR NO_X Ozone Season unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR NO_X Ozone Season unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR NO_X Ozone Season unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average Ozone Season fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu basis) and an average Ozone Season fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average Ozone Season fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average Ozone Season fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average Ozone Season fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Ozone Season Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other

equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Ozone Season Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.505 Retired unit exemption.

(a)(1) Any TR NO_X Ozone Season unit that is permanently retired and is not a TR NO_X Ozone Season opt-in unit shall be exempt from § 97.506(b) and (c)(1), § 97.524, and §§ 97.530 through 97.535.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NO_X Ozone Season unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR NO_X Ozone Season Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.506 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.513 through 97.518.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.530 through 97.535.

(2) The emissions data determined in accordance with §§ 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under §§ 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *NO_X emissions requirements*—(1) *TR NO_X Ozone Season emissions limitation.* (i) As of the allowance transfer deadline for a control period, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under § 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

(ii) If a TR NO_X Ozone Season source emits NO_X during any control period in excess of the TR NO_X Ozone Season emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under § 97.524(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR NO_X Ozone Season assurance provisions. (i) If the total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such NO_X emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.525(b)(4)(ii), TR NO_X Ozone Season allowances available for deduction for such control period under § 97.525(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.525(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such NO_X emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such NO_X emissions exceeds that owner's assurance level; and

(B) The amount by which total NO_X emissions for all TR NO_X Ozone Season

units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR NO_X Ozone Season allowances required under paragraph (c)(2)(i) of this section, as of midnight of August 1 (if it is a business day), or midnight of the first business day thereafter (if August 1 is not a business day), immediately after such control period.

(iii) The total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of NO_X emissions exceeds the sum, for such control period, of the State NO_X Ozone Season trading budget and the State's one-year variability limit under § 97.510(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of NO_X emissions and the total amounts of NO_X emissions from all TR NO_X Ozone Season units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State NO_X Ozone Season trading budget and the State's three-year variability limit under § 97.510(b);

(C) Provided that the amount by which such total amount of NO_X emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period exceeds the State assurance level or if an owner's share of total NO_X emissions from the TR NO_X Ozone Season units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR NO_X Ozone Season allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Ozone Season allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR NO_X Ozone Season unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of September 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.530(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of September 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.530(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR NO_X Ozone Season allowance was allocated.

(5) *Allowance Management System requirements.* Each TR NO_X Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X in accordance with the TR NO_X Ozone Season Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR NO_X Ozone Season allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Ozone Season allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.530 through 97.535 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.*

(1) Unless otherwise provided, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.516 for the designated representative for the source and each TR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 97.516 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Ozone Season Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall make all submissions required under the TR NO_X Ozone Season Trading Program, including any submissions required for compliance with the TR NO_X Ozone Season assurance provisions. This requirement does not change, create an exemption from, or or otherwise affect the responsible official submission requirements under a title V operating

permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season source or the designated representative of a TR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season units at the source.

(2) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season unit or the designated representative of a TR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR NO_X Ozone Season Trading Program or exemption under § 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Ozone Season source or TR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.507 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NO_X Ozone Season Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR NO_X Ozone Season Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR NO_X Ozone Season Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.508 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NO_X Ozone Season Trading Program are set forth in part 78 of this chapter.

§ 97.509 [Reserved]

§ 97.510 State NO_X Ozone Season trading budgets, new-unit set-asides, and variability limits.

(a) The State NO_X Ozone Season trading budgets and new-unit set-asides for allocations of TR NO_X Ozone Season allowances for the control periods in 2012 and thereafter are as follows:

State	NO_X ozone season trading budget (tons)*	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Alabama	29,738	892
Arkansas	16,660	500
Connecticut	1,315	39
Delaware	2,450	74
District of Columbia	105	3
Florida	56,939	1,708
Georgia	32,144	964
Illinois	23,570	707
Indiana	49,987	1,500
Kansas	21,433	643
Kentucky	30,908	927
Louisiana	21,220	637
Maryland	7,232	217
Michigan	28,253	848
Mississippi	16,530	496
New Jersey	5,269	158
New York	11,090	333
North Carolina	23,539	706
Ohio	40,661	1,220
Oklahoma	37,087	1,113
Pennsylvania	48,271	1,448
South Carolina	15,222	457
Tennessee	11,575	347
Texas	75,574	2,267
Virginia	12,608	378
West Virginia	22,234	667
Total	641,614	19,249

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State NO_X Ozone Season trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Alabama	2,974	1,717
Arkansas	2,100	1,212
Connecticut	2,100	1,212
Delaware	2,100	1,212
District of Columbia	2,100	1,212
Florida	5,694	3,287
Georgia	3,214	1,856
Illinois	2,357	1,361
Indiana	4,999	2,886
Kansas	2,143	1,237
Kentucky	3,091	1,784
Louisiana	2,122	1,225
Maryland	2,100	1,212
Michigan	2,825	1,631
Mississippi	2,100	1,212
New Jersey	2,100	1,212
New York	2,100	1,212
North Carolina	2,354	1,359
Ohio	4,066	2,348
Oklahoma	3,709	2,141
Pennsylvania	4,827	2,787
South Carolina	2,100	1,212
Tennessee	2,100	1,212
Texas	7,557	4,363
Virginia	2,100	1,212
West Virginia	2,223	1,284

§ 97.511 Timing requirements for TR NO_X Ozone Season allowance allocations.

(a) *Existing units.* (1) TR NO_X Ozone Season allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR NO_X Ozone Season unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR NO_X Ozone Season unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR NO_X Ozone Season allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR NO_X Ozone Season allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR NO_X Ozone Season allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO_X Ozone Season allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By April 1, 2012 and April 1 of each year thereafter, the Administrator will calculate the TR NO_X Ozone Season allowance allocation for each TR NO_X Ozone Season unit, in accordance with § 97.512, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.512 and §§ 97.506(b)(2) and 97.530 through 97.535.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By June 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR NO_X Ozone Season units.* For each control period in 2012 and thereafter, if the Administrator determines that TR NO_X Ozone Season allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR NO_X Ozone Season unit under § 97.504 as of May 1, 2012 or whose deadline for meeting monitor certification requirements under § 97.530(b)(1) and (2) is after May 1, 2012 or if the Administrator determines that TR NO_X Ozone Season allowances were allocated under paragraph (b) of this section and § 97.512 for the control period to a recipient that is not actually a TR NO_X Ozone Season unit under § 97.504 as of May 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR NO_X Ozone Season allowances under § 97.521.

(2) If the Administrator already recorded such TR NO_X Ozone Season allowances under § 97.521 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will deduct from the account in which such TR NO_X Ozone Season allowances

were recorded an amount of TR NO_X Ozone Season allowances allocated for the same or a prior control period equal to the amount of such already recorded TR NO_X Ozone Season allowances. The authorized account representative shall ensure that there are sufficient TR NO_X Ozone Season allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR NO_X Ozone Season allowances under § 97.521 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR NO_X Ozone Season allowances.

(4) The Administrator will transfer the TR NO_X Ozone Season allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, if such notice has been promulgated, in the next year.

§ 97.512 TR NO_X Ozone Season allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR NO_X Ozone Season allowances to TR NO_X Ozone Season units in a State that are not listed in appendix A to this subpart, to TR NO_X Ozone Season units that are so listed and whose allocation of NO_X Ozone Season allowances for such control period is covered by § 97.511(c)(1) or (2), and to TR NO_X Ozone Season units that are so listed and, pursuant to § 97.511(a)(2), are not allocated TR NO_X Ozone Season allowances for such control period but that operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR NO_X Ozone Season allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.510(a). Each new unit set-aside will be allocated additional TR NO_X Ozone Season allowances in accordance with § 97.511(a)(2) and (c)(4).

(2) The designated representative of such TR NO_X Ozone Season unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR NO_X Ozone Season allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR NO_X Ozone Season unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before February 1 immediately preceding the first control period for which TR NO_X Ozone Season allowances are sought and after the date on which the TR NO_X Ozone Season unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR NO_X Ozone Season allowances in an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(3) The Administrator will review each TR NO_X Ozone Season allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR NO_X Ozone Season allowances for each control period pursuant to an accepted request as follows:

(i) After February 1 immediately preceding such control period, the Administrator will determine the sum of the TR NO_X Ozone Season allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR NO_X Ozone Season allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR NO_X Ozone Season allowances requested to each TR NO_X Ozone Season unit covered by an accepted allowance allocation request.

(iii) If the amount of TR NO_X Ozone Season allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR NO_X Ozone Season unit covered by an accepted allowance allocation request the amount of the TR NO_X Ozone Season allowances requested, multiplied by the amount of TR NO_X Ozone Season allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.511(b), each designated representative that submitted an allowance allocation request of the amount of TR NO_X Ozone Season allowances (if any) allocated for such control period to the TR NO_X Ozone Season unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR NO_X Ozone Season allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR NO_X Ozone Season unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR NO_X Ozone Season allowances for such control period in accordance with § 97.511(a)(2), an amount of TR NO_X Ozone Season allowances equal to the following: The total amount of such remaining unallocated TR NO_X Ozone Season allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.511(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.513 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.515, each TR NO_X Ozone Season source, including all TR NO_X Ozone Season units at the source, shall have one and only one designated representative, with regard to all matters under the TR NO_X Ozone Season Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR NO_X Ozone Season unit at

the source in all matters pertaining to the TR NO_X Ozone Season Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.515, each TR NO_X Ozone Season source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.502, and §§ 97.514 through 97.518, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.514 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.518 concerning delegation of authority to make submissions, each submission under the TR NO_X Ozone Season Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NO_X Ozone Season source and TR NO_X Ozone Season unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.518.

§ 97.515 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NO_X Ozone Season source and the TR NO_X Ozone Season units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NO_X Ozone Season source and the TR NO_X Ozone Season units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit is not included in the list of owners and operators in the certificate of representation under § 97.516, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.516 amending the list of owners and operators to include the change.

§ 97.516 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NO_X Ozone Season source, and each TR NO_X Ozone Season unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NO_X Ozone Season source and of each TR NO_X Ozone Season unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NO_X Ozone Season unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Ozone Season Trading Program on behalf of the owners and operators of the source and of each TR NO_X Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR NO_X Ozone Season unit, or where a utility or industrial customer purchases power from a TR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR NO_X Ozone Season unit at the source; and TR NO_X Ozone Season allowances and proceeds of transactions involving TR NO_X Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR NO_X Ozone Season allowances by contract, TR NO_X Ozone Season allowances and proceeds of transactions involving TR NO_X Ozone Season allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.517 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.516 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.516 is received by the Administrator.

(b) Except as provided in § 97.515(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NO_X Ozone Season Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NO_X Ozone Season allowance transfers.

§ 97.518 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.518 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.519 [Reserved]

§ 97.520 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.516, the Administrator will establish a compliance account for the TR NO_X Ozone Season source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source

shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring TR NO_X Ozone Season allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR NO_X Ozone Season allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Ozone Season Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account in all matters pertaining to the TR NO_X Ozone Season Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO_X Ozone Season allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new

alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO_X Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Ozone Season allowances in the general account, including the addition of a new person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NO_X Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NO_X Ozone Season allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.520(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR NO_X Ozone Season allowance transfer under § 97.522 for any TR NO_X Ozone Season allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR NO_X Ozone Season allowance transfers to or from the account for a 12-month period or longer and does not contain any TR NO_X Ozone Season allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted TR NO_X Ozone Season allowance transfer under § 97.522 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good

cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR NO_X Ozone Season allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.514(a) and 97.518 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.521 Recordation of TR NO_X Ozone Season allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated for the TR NO_X Ozone Season units at the source in accordance with §§ 97.511(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated for the TR NO_X Ozone Season units at the source in accordance with § 97.511(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated for the TR NO_X Ozone Season units at the source in accordance with § 97.512 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR NO_X Ozone Season allowances for a TR NO_X Ozone Season unit in a compliance account, the Administrator will assign each TR NO_X Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the TR NO_X Ozone Season allowance is allocated.

§ 97.522 Submission of TR NO_X Ozone Season allowance transfers.

(a) An authorized account representative seeking recordation of a TR NO_X Ozone Season allowance transfer shall submit the transfer to the Administrator.

(b) A TR NO_X Ozone Season allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR NO_X Ozone Season allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR NO_X Ozone Season allowance identified by serial number in the transfer.

§ 97.523 Recordation of TR NO_X Ozone Season allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NO_X Ozone Season allowance transfer, the Administrator will record a TR NO_X Ozone Season allowance transfer by moving each TR NO_X Ozone Season allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.522.

(b)(1) A TR NO_X Ozone Season allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NO_X Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.524 for the control period immediately before such allowance transfer deadline.

(2) A TR NO_X Ozone Season allowance transfer that is submitted for recordation after the deadline for holding TR NO_X Ozone Season allowances described in § 97.525(b)(5) and that includes any TR NO_X Ozone Season allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.525 for the control period immediately before the year of such deadline.

(c) Where a TR NO_X Ozone Season allowance transfer is not correctly submitted under § 97.522, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR NO_X Ozone Season allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR NO_X Ozone Season allowance transfer that is not correctly submitted under § 97.522, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.524 Compliance with TR NO_X Ozone Season emissions limitation.

(a) *Availability for deduction for compliance.* TR NO_X Ozone Season allowances are available to be deducted for compliance with a source's TR NO_X Ozone Season emissions limitation for a control period in a given year only if the TR NO_X Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.523, of TR NO_X Ozone Season allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR NO_X Ozone Season allowances available under paragraph (a) of this section in order to determine whether the source meets the TR NO_X Ozone Season emissions limitation for such control period, as follows:

(1) Until the amount of TR NO_X Ozone Season allowances deducted equals the number of tons of total NO_X emissions from all TR NO_X Ozone Season units at the source for such control period; or

(2) If there are insufficient TR NO_X Ozone Season allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NO_X Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR NO_X Ozone Season allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR NO_X Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in

accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NO_X Ozone Season source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Ozone Season allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Ozone Season allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Ozone Season allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Ozone Season allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NO_X Ozone Season source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR NO_X Ozone Season allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.525 Compliance with TR NO_X Ozone Season assurance provisions.

(a) *Availability for deduction.* TR NO_X Ozone Season allowances are available to be deducted for compliance with the TR NO_X Ozone Season assurance provisions for a control period in a given year by an owner of one or more TR NO_X Ozone Season units in a State only if the TR NO_X Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance with paragraph (b)(4)(ii) of this section, of one of the owner's TR NO_X Ozone Season sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR NO_X Ozone Season allowances available under paragraph (a) of this section for compliance with the TR NO_X Ozone Season assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By March 1, 2015 and March 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of NO_X emissions from all TR NO_X Ozone Season units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.506(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions for each TR NO_X Ozone Season unit and of the amounts described in §§ 97.506(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR NO_X Ozone Season unit and each State for the control period in the year involved are in accordance with § 97.506(c)(2)(iii) and §§ 97.506(b) and 97.530 through 97.535.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By May 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR NO_X Ozone Season sources with total NO_X emissions exceeding the State assurance level for a control period, as described in § 97.506(c)(2)(iii):

(i) By May 15 immediately after the promulgation of such notice, the designated representative of each TR NO_X Ozone Season source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR NO_X Ozone Season unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.502, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR NO_X Ozone Season unit at the source that operates during, but is allocated no TR NO_X Ozone Season allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable NO_X emission rate for such control period.

(ii) By June 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR NO_X Ozone Season units in the State and for the control period in the year involved, each owner's share of the total NO_X emissions from all TR NO_X Ozone Season units in the State, each owner's assurance level, and the amount (if any) of TR NO_X Ozone Season allowances that each owner must hold in accordance with the calculation formula in § 97.506(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the NO_X emissions for the relevant TR NO_X Ozone Season units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.502, and the calculation formula in § 97.506(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section.

By August 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By September 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR NO_X Ozone Season units in a State and as being required to hold TR NO_X Ozone Season allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR NO_X Ozone Season allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of September 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR NO_X Ozone Season allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if September 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After September 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.523, of TR NO_X Ozone Season allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR NO_X Ozone Season allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR NO_X Ozone Season allowances deducted equals the amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR NO_X Ozone Season allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR NO_X Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR NO_X Ozone Season allowances that each owner is required to hold in accordance with § 97.506(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Ozone Season allowances that owners are required to hold in accordance with the calculation formula in § 97.506(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Ozone Season allowances that owners are required to hold in accordance with the calculation formula in § 97.506(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR NO_X Ozone Season allowances that an owner is required to hold for the control period in the year involved with regard to the State involved-

(A) Where the amount of TR NO_X Ozone Season allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR NO_X Ozone Season allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR NO_X Ozone Season allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR NO_X Ozone Season allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR NO_X Ozone Season allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance

account) for the control period in the year involved.

(C) Each TR NO_X Ozone Season allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements for compliance with the TR NO_X Ozone Season assurance provisions for a control period in a given year must be a TR NO_X Ozone Season allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR NO_X Ozone Season allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR NO_X Ozone Season allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Ozone Season allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Ozone Season allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Ozone Season allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Ozone Season allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.526 Banking.

(a) A TR NO_X Ozone Season allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR NO_X Ozone Season allowance that is held in a compliance account or a general account will remain in such account unless and until the TR NO_X Ozone Season allowance is deducted or transferred under § 97.511(c), § 97.523, § 97.524, § 97.525, 97.527, 97.528, 97.542, or 97.543.

§ 97.527 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.528 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO_X Ozone Season Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO_X Ozone Season allowances from or transfer TR NO_X Ozone Season allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.529 [Reserved]

§ 97.530 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO_X Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.502 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR NO_X Ozone Season unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.502, and the term "newly affected unit" shall be deemed to mean "newly affected TR NO_X Ozone Season unit". The owner or operator of a unit that is not a TR NO_X Ozone Season unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR NO_X Ozone Season unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR NO_X Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 97.531 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation before July 1, 2011, by May 1, 2012.

(2) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on an annual basis under § 97.534(d), by the later of the following dates:

(i) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) May 1, 2012.

(3) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on a control period basis under § 97.534(d)(2)(ii), by the later of the following dates:

(i) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately after the compliance date under paragraph (b)(3)(i) of this section.

(4) For the owner or operator of a TR NO_X Ozone Season unit for which

construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section and that reports on an annual basis under § 97.534(d), by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls.

(5) For the owner or operator of a TR NO_X Ozone Season unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1) or (3) of this section and that reports on a control period basis under § 97.534(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls; or

(ii) If the compliance date under paragraph (b)(5)(i) of this section is not during a control period, May 1 immediately after the compliance date under paragraph (b)(5)(i) of this section.

(6) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.541(c).

(7) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a TR NO_X Ozone Season opt-in unit, by the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Ozone Season Trading Program as provided in § 97.541(h).

(c) *Reporting data.* The owner or operator of a TR NO_X Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR NO_X Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.535.

(2) No owner or operator of a TR NO_X Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR NO_X Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR NO_X Ozone Season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.505 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.531(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR NO_X Ozone Season unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.531 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NO_X Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.530(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.530(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.535 to determine whether the approval applies under the TR NO_X Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NO_X Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.530(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.530(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.530(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.530(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter systems, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 97.530(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.530(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.533.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NO_X Ozone Season Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR NO_X Ozone Season Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period specified in paragraph (d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.532(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(2) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(4) For a disapproved fuel flowmeter system, the maximum potential fuel

flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(5) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.532 Monitoring system out-of-control periods.

(*a*) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(*b*) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.531 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.531 for each disapproved monitoring system.

§ 97.533 Notifications concerning monitoring.

The designated representative of a TR NO_X Ozone Season unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.534 Recordkeeping and reporting.

(*a*) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.514(a).

(*b*) *Monitoring plans.* The owner or operator of a TR NO_X Ozone Season unit shall comply with requirements of § 75.73(c) and (e) of this chapter.

(*c*) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.531, including the information required under § 75.63 of this chapter.

(*d*) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) If the TR NO_X Ozone Season unit is subject to the Acid Rain Program or a TR NO_X Annual emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for such unit for the entire year and shall report the NO_X mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b), unless that quarter is the third or fourth quarter of 2011 or the first quarter of 2012, in which case reporting shall commence in the quarter covering May 1, 2012 through June 30, 2012;

(2) If the TR NO_X Ozone Season unit is not subject to the Acid Rain Program or a TR NO_X Annual emissions limitation, then the designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit in accordance with paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (including the requirements in § 75.74(c) of this chapter) and report NO_X mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(A) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012;

(B) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date;

(3) Notwithstanding paragraphs (d)(1) and (2) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.541(c); and

(4) Notwithstanding paragraphs (d)(1) and (2) of this section, for a TR NO_X

Ozone Season opt-in unit, the calendar quarter corresponding to the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Ozone Season Trading Program as provided in § 97.541(h).

(5) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(6) For TR NO_X Ozone Season units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 1 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(7) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(8) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(5) of this section.

(*e*) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

§ 97.535 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NO_X Ozone Season unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.530 through 97.534 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.502.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.540 General requirements for TR NO_X Ozone Season opt-in units.

(a) A TR NO_X Ozone Season opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR NO_X Ozone Season unit under § 97.504;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR NO_X Ozone Season opt-in unit shall be deemed to be a TR NO_X Ozone Season unit for purposes of applying this subpart, except for §§ 97.505, 97.511, and 97.512.

(c) Solely for purposes of applying the requirements of §§ 97.513 through 97.518 and §§ 97.530 through 97.535, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.542 shall be deemed to be a TR NO_X Ozone Season unit.

(d) Any TR NO_X Ozone Season opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.542, located at the same source as one or more TR NO_X Ozone Season units shall have the same designated representative and alternate designated representative as such TR NO_X Ozone Season units.

§ 97.541 Opt-in process.

A unit meeting the requirements for a TR NO_X Ozone Season opt-in unit in § 97.540(a) may become a TR NO_X Ozone Season opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt-in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.542(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located,

including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR NO_X Ozone Season unit under § 97.504;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.530 through 97.535;

(4) A statement that the unit, if approved to become a TR NO_X Ozone Season unit under paragraph (g) of this section, may withdraw from the TR NO_X Ozone Season Trading Program only in accordance with § 97.542;

(5) A statement that the unit, if approved to become a TR NO_X Ozone Season unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.543;

(6) A complete certificate of representation under § 97.516 consistent with § 97.540, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) *Interim review of monitoring plan.* The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.530 through 97.535. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) *Monitoring and reporting.* (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the NO_X emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.530 through 97.535, starting on the date of certification of the necessary monitoring systems under §§ 97.530 through 97.535 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR NO_X Ozone Season Trading Program in accordance with § 97.542.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR NO_X Ozone Season Trading Program under paragraph (h) of this section, during which period monitoring system availability must not be less than 98 percent under §§ 97.530 through 97.535 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emissions rate and the heat input of the unit are monitored and reported in accordance with §§ 97.530 through 97.535 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.530 through 97.535 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR NO_X Ozone Season Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's NO_X emission rate (in lb/mmBtu) for such control period;

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods during which the unit has add-on NO_X emission controls.

(g) *Review of TR opt-in application.*

(1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR NO_X Ozone Season opt-in unit in § 97.540, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approve will state the unit's baseline heat input and baseline NO_X emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR NO_X Ozone Season opt-in unit in § 97.540, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) Date of entry into TR NO_X Ozone Season Trading Program. A unit for which a TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR NO_X Ozone Season opt-in unit, and a TR NO_X Ozone Season unit, effective as of the later of May 1, 2012 or May 1 of the first control period during which such approval is issued.

§ 97.542 Withdrawal of TR NO_X Ozone Season opt-in unit from TR NO_X Ozone Season Trading Program.

A TR NO_X Ozone Season opt-in unit may withdraw from the TR NO_X Ozone Season Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR NO_X Ozone Season opt-in unit from the TR NO_X Ozone Season Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of September 30 of a specified calendar year, which date must be at least 4 years after September 30 of the year of the unit's entry into the TR NO_X Ozone Season Trading Program under § 97.541(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR NO_X Ozone Season opt-in unit covered by the request to withdraw may withdraw from the TR NO_X Ozone Season Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR NO_X Ozone Season opt-in unit must meet the requirement to hold TR NO_X Ozone Season allowances under §§ 97.524 and 97.525 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit TR NO_X Ozone Season allowances equal in amount to and allocated for the same or a prior control period as any TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under § 97.544 for any control period after the date on which the withdrawal is to be effective. If there are no other TR NO_X Ozone Season units at the source, the Administrator will close the compliance account, and the owners and operators of the TR NO_X Ozone Season opt-in unit may submit a TR NO_X Ozone Season allowance transfer for any remaining TR NO_X Ozone Season allowances to another Allowance Management System account in accordance §§ 97.522 and 97.523.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR NO_X Ozone Season allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on September 30 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR NO_X Ozone Season opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR NO_X Ozone Season Trading Program concerning any control periods for which the unit is a TR NO_X Ozone Season opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR NO_X Ozone Season opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR NO_X Ozone Season Trading Program.* Once a TR NO_X Ozone Season opt-in unit withdraws from the TR NO_X Ozone Season Trading Program, the designated representative may not submit another opt-in application under § 97.541 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.543 Change in regulatory status.

(a) *Notification.* If a TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR NO_X Ozone Season opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, the Administrator will deduct, from the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit that becomes a TR NO_X Ozone Season unit under § 97.504, TR NO_X Ozone Season allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under § 97.544 for any control period starting after the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504; and

(ii) If the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504 is not September 30, the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under § 97.544 for the control period that includes the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit that becomes a TR NO_X Ozone Season unit under § 97.504 contains the TR NO_X Ozone Season allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, the TR NO_X Ozone Season opt-in unit will be allocated TR NO_X Ozone Season allowances in accordance with § 97.512.

(ii) If the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504 is not September 30, the following amount of TR NO_X Ozone Season allowances will be allocated to the TR NO_X Ozone Season opt-in unit (as a TR NO_X Ozone Season unit) in accordance with § 97.512 for the control period that includes the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504:

(A) The amount of TR NO_X Ozone Season allowances otherwise allocated to the TR NO_X Ozone Season opt-in unit (as a TR NO_X Ozone Season unit) in accordance with § 97.512 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, divided by the total number of days in the control period; and

(C) Rounded to the nearest allowance.

§ 97.544 TR NO_X Ozone Season allowance allocations to TR NO_X Ozone Season opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.541(g), the Administrator will issue TR NO_X Ozone Season allowances and allocate them to the unit for the control period in which the unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h), in accordance with paragraph (b) of this section.

(2) By no later than July 30 of the control period after the control period in which a TR NO_X Ozone Season opt-in unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h) and July 30 of each year thereafter, the Administrator will issue TR NO_X Ozone Season allowances and allocate them to the TR NO_X Ozone Season opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR NO_X Ozone Season opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR NO_X Ozone Season opt-in unit is to be allocated TR NO_X Ozone Season allowances, the Administrator will issue and allocate TR NO_X Ozone Season allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR NO_X Ozone Season allowance allocation will be the lesser of:

(i) The TR NO_X Ozone Season opt-in unit's baseline heat input determined under § 97.541(g); or

(ii) The TR NO_X Ozone Season opt-in unit's heat input, as determined in accordance with §§ 97.530 through 97.535, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR NO_X Ozone Season opt-in unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating TR NO_X Ozone Season allowance allocations will be the lesser of:

(i) The TR NO_X Ozone Season opt-in unit's baseline NO_X emission rate (in lb/mmBtu) determined under § 97.541(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the TR NO_X Ozone Season opt-in unit at any time during the control period for which TR NO_X Ozone Season allowances are to be allocated.

(3) The Administrator will issue TR NO_X Ozone Season allowances and allocate them to the TR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit, the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under paragraph (a)(1) of this section.

(2) By September 1 of the control period after the control period in which a TR NO_X Ozone Season opt-in unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h) and September 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit, the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under paragraph (a)(2) of this section.

37. Part 97 is amended by adding subpart CCCCC to read as follows:

Subpart CCCCC—TR SO_2 Group 1 Trading Program

Sec.

Subpart CCCCC—TR SO_2 Group 1 Trading Program

§ 97.601 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO_2 Group 1 Trading Program, under section 110 of the Clean Air Act and § 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.602 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United

States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR SO_2 Group 1 allowances, the determination by the Administrator of the amount of such TR SO_2 Group 1 allowances to be initially credited to a TR SO_2 Group 1 source or a new unit set-aside.

Allowable SO_2 emission rate means, with regard to a unit, the SO_2 emission rate limit that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR SO_2 Group 1 allowances under the TR SO_2 Group 1 Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR SO_2 Group 1 allowances and data related to SO_2 emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO_2 Group 1 allowances.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 1 allowance transfer must be submitted for recordation in a TR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 1 Annual emissions limitation for such control period in accordance with § 97.624.

Alternate designated representative means, for a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO_2 Group 1 Trading Program. If the TR SO_2 Group 1 source is also subject to the Acid Rain Program, TR NO_X Annual Season Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR SO_2 Group 1 allowances held in the general account and, with regard to a TR SO_2 Group 1 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph

(2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.605.

(i) For a unit that is a TR SO_2 Group 1 unit under § 97.604 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO_2 Group 1 unit under § 97.604 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.605, for a unit that is not a TR SO_2 Group 1 unit under § 97.604 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR SO_2 Group 1 unit under § 97.604.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR SO_2 Group 1 source under this subpart, in which any TR SO_2 Group 1 allowance allocations for the TR SO_2 Group 1 units at the source are recorded and in which are held any TR SO_2 Group 1 allowances available for use for a control period in complying with the source's TR SO_2 Group 1 emissions limitation in accordance with § 97.624 and the TR SO_2 Group 1 assurance provisions in accordance with § 97.625.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.630 through 97.635. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO_2 monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.606(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO_2 Group 1 Trading Program. If the TR SO_2 Group 1 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of SO_2 emitted from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source during a control period that exceeds the TR SO_2 Group 1 emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.604(b)(2)(i)(B), 97.604(b)(2)(ii)(B), and 97.604(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR SO_2 Group 1 unit means a unit that was not a TR SO_2 Group 1 unit when it began operating but that thereafter becomes a TR SO_2 Group 1 unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR SO_2 Group 1 unit or a TR SO_2 Group 1 source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit;

(2) Any holder of a leasehold interest in a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit, provided that, unless expressly provided for in a leasehold agreement, "owner" shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR SO_2 Group 1 unit;

(3) Any purchaser of power from a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR SO_2 Group 1 assurance provisions in §§ 97.606(c)(2) and 97.625, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR SO_2 Group 1 units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.606(c)(2)(iii)(A) and not as described in § 97.606(c)(2)(iii)(B), the owner's share of the State SO_2 Group 1 trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.606(c)(2)(iii)(B), the owner's share of the State SO_2 Group 1 trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period, the total tonnage of SO_2 emissions during such control period from all of the owner's TR SO_2 Group 1 units in the State;

(2) With regard to a State SO_2 Group 1 trading budget with a one-year variability limit for a control period, the

amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 1 allowances allocated for such control period to all of the owner's TR SO_2 Group 1 units in the State, multiplied by the sum of the State SO_2 Group 1 trading budget under § 97.610(a) and the State's one-year variability limit under § 97.610(b) and divided by such State SO_2 Group 1 trading budget;

(3) With regard to a State SO_2 Group 1 trading budget with a three-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 1 allowances allocated for such control period to all of the owner's TR SO_2 Group 1 units in the State, multiplied by the sum of the State SO_2 Group 1 trading budget under § 97.610(a) and the State's three-year variability limit under § 97.610(b) and divided by such State SO_2 Group 1 trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of SO_2 emissions and of TR SO_2 Group 1 allowances allocated for a control period, with regard to such unit, used in determining each owner's share shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's SO_2 emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of December 31 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which SO_2 mass emissions are reported for a control period for a year, the amount of tonnage of each unit's SO_2 emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of SO_2 emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be *de minimis;* or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.635; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR SO_2 Group 1 allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO_2 Group 1 allowances for such control period equal to the lesser of—

(i) The unit's allowable SO_2 emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.84 (if the unit is a coal-fired boiler), 0.15 (if the unit is a simple combustion turbine), or 0.66 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's SO_2 emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR SO_2 Group 1 allowances, the moving of TR SO_2 Group 1 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR SO_2 Group 1 allowance, the unique identification number assigned to each TR SO_2 Group 1 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source", "stationary source", or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR SO_2 Group 1 Trading Program pursuant to § 52.38(b) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,
W = weight % of moisture in the form of energy, and
H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart AAAAA and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart BBBBB of this part and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 1 allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of SO_2 during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR SO_2 Group 1 Trading Program.

TR SO_2 Group 1 allowance deduction or deduct TR SO_2 Group 1 allowances means the permanent withdrawal of TR SO_2 Group 1 allowances by the Administrator from a compliance account, *e.g.,* in order to account for compliance with the TR SO_2 Group 1 emissions limitation or assurance provisions.

TR SO_2 Group 1 allowances held or hold TR SO_2 Group 1 allowances means the TR SO_2 Group 1 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR SO_2 Group 1 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR SO_2 Group 1 allowance transfer in accordance with this subpart.

TR SO_2 Group 1 emissions limitation means, for a TR SO_2 Group 1 source, the tonnage of SO_2 emissions authorized in a control period by the TR SO_2 Group 1 allowances available for deduction for the source under § 97.624(a) for such control period.

TR SO_2 Group 1 source means a source that includes one or more TR SO_2 Group 1 units.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 1 unit means a unit that is subject to the TR SO_2 Group 1 Trading Program under § 97.604.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.603 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.604 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR SO_2 Group 1 units, and any source that includes one or more such units shall be a TR SO_2 Group 1 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO_2 Group 1 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO_2 Group 1 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR SO_2 Group 1 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR SO_2 Group 1 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 1 Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 1 Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.605 Retired unit exemption.

(a)(1) Any TR SO_2 Group 1 unit that is permanently retired and is not a TR SO_2 Group 1 opt-in unit shall be exempt from § 97.606(b) and (c)(1), § 97.624, and §§ 97.630 through 97.635.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO_2 Group 1 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.606 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.613 through 97.618.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.630 through 97.635.

(2) The emissions data determined in accordance with §§ 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under §§ 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *SO_2 emissions requirements*—(1) *TR SO_2 Group 1 emissions limitation.* (i) As of the allowance transfer deadline for

a control period, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under § 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(ii) If a TR SO_2 Group 1 source emits SO_2 during any control period in excess of the TR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under § 97.624(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) *TR SO_2 Group 1 assurance provisions.* (i) If the total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such SO_2 emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.625(b)(4)(ii), TR SO_2 Group 1 allowances available for deduction for such control period under § 97.625(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.625(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such SO_2 emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such SO_2 emissions exceeds that owner's assurance level; and

(B) The amount by which total SO_2 emissions for all TR SO_2 Group 1 units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR SO_2 Group 1 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) The total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of SO_2 emissions exceeds the sum, for such control period, of the State SO_2 Group 1 trading budget and the State's one-year variability limit under § 97.610(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of SO_2 emissions and the total amounts of SO_2 emissions from all TR SO_2 Group 1 units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State SO_2 Group 1 trading budget and the State's three-year variability limit under § 97.610(b);

(C) Provided that the amount by which such total amount of SO_2 emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period exceeds the State assurance level or if an owner's share of total SO_2 emissions from the TR SO_2 Group 1 units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR SO_2 Group 1 allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO_2 Group 1 allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR SO_2 Group 1 unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR SO_2 Group 1 allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR SO_2 Group 1 allowance was allocated.

(5) *Allowance Management System requirements.* Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 in accordance with the TR SO_2 Group 1 Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR SO_2 Group 1 allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 1 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under §§ 75.10, 75.11, and 75.16 of this chapter), an excepted monitoring system (under appendix D to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.630 through 97.635 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor

permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.616 for the designated representative for the source and each TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 1 Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR SO_2 Group 1 Trading Program, including any submissions required for compliance with the TR SO_2 Group 1 assurance provisions. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(2) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR SO_2 Group 1 Trading Program or exemption under § 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.607 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 1 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 1 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR SO_2 Group 1 Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.608 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO_2 Group 1 Trading Program are set forth in part 78 of this chapter.

§ 97.609 [Reserved]

§ 97.610 State SO_2 Group 1 trading budgets, new-unit set-asides, and variability limits.

(a) The State SO_2 Group 1 trading budgets and new-unit set-asides for allocations of TR SO_2 Group 1 allowances for the control periods in 2012 and thereafter are as follows:

State	SO_2 Group 1 trading budget (tons) *		New-unit set-aside (tons)	
	For 2012–2013	For 2014 and thereafter	For 2012–2013	For 2014 and thereafter
Georgia	233,260	85,717	6,998	2,572
Illinois	208,957	151,530	6,269	4,546
Indiana	400,378	201,412	12,011	6,042
Iowa	94,052	86,088	2,822	2,583
Kentucky	219,549	113,844	6,586	3,415
Michigan	251,337	155,675	7,540	4,670
Missouri	203,689	158,764	6,111	4,763
New York	66,542	42,041	1,996	1,261
North Carolina	111,485	81,859	3,345	2,456
Ohio	464,964	178,307	13,949	5,349
Pennsylvania	388,612	141,693	11,658	4,251
Tennessee	100,007	100,007	3,000	3,000
Virginia	72,595	40,785	2,178	1,224
West Virginia	205,422	119,016	6,163	3,570
Wisconsin	96,439	66,683	2,893	2,000
Total	3,117,288	1,723,421	93,519	51,703

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State SO_2 Group 1 trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Georgia	8,572	4,949
Illinois	15,153	8,749
Indiana	20,141	11,629
Iowa	8,609	4,970
Kentucky	11,384	6,573
Michigan	15,568	8,988
Missouri	15,876	9,166
New York	4,204	2,427
North Carolina	8,186	4,726
Ohio	17,831	10,295
Pennsylvania	14,169	8,181
Tennessee	10,001	5,774
Virginia	4,079	2,355
West Virginia	11,902	6,871
Wisconsin	6,668	3,850

§ 97.611 Timing requirements for TR SO_2 Group 1 allowance allocations.

(a) *Existing units.* (1) TR SO_2 Group 1 allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR SO_2 Group 1 unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR SO_2 Group 1 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR SO_2 Group 1 allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR SO_2 Group 1 allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR SO_2 Group 1 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO_2 Group 1 allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By July 1, 2012 and July 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 1 allowance allocation for each TR SO_2 Group 1 unit, in accordance with § 97.612, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.612 and §§ 97.606(b)(2) and 97.630 through 97.635.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By September 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR SO_2 Group 1 units.* For each control period in 2012 and thereafter, if the Administrator determines that TR SO_2 Group 1 allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR SO_2 Group 1 unit under § 97.604 as of January 1, 2012 or whose deadline for meeting monitor certification requirements under § 97.630(b)(1) and (2) is after January 1, 2012 or if the Administrator determines that TR SO_2 Group 1 allowances were allocated under paragraph (b) of this section and § 97.612 for the control period to a recipient that is not actually a TR SO_2 Group 1 unit under § 97.604 as of January 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR SO_2 Group 1 allowances under § 97.621.

(2) If the Administrator already recorded such TR SO_2 Group 1 allowances under § 97.621 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.624(b) for such control period, then the Administrator will deduct from the account in which such TR SO_2 Group 1 allowances were recorded an amount of TR SO_2 Group 1 allowances allocated for the same or a prior control period equal to the amount of such already recorded TR SO_2 Group 1 allowances. The authorized account representative shall ensure that there are sufficient TR SO_2 Group 1 allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR SO_2 Group 1 allowances under § 97.621 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.624(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO_2 Group 1 allowances.

(4) The Administrator will transfer the TR SO_2 Group 1 allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, if such notice has been promulgated, in the next year.

§ 97.612 TR SO_2 Group 1 allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR SO_2 Group 1 allowances to TR SO_2 Group 1 units in a State that are not listed in appendix A to this subpart, to TR SO_2 Group 1 units that are so listed and whose allocation of SO_2 Group 1 allowances for such control period is covered by § 97.611(c)(1) or (2), and to TR SO_2 Group 1 units that are so listed and, pursuant to § 97.611(a)(2), are not allocated TR SO_2 Group 1 allowances for such control period but that operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR SO_2 Group 1 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.610(a). Each new unit set-aside will be allocated additional TR SO_2 Group 1 allowances in accordance with § 97.611(a)(2) and (c)(4).

(2) The designated representative of such TR SO_2 Group 1 unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR SO_2 Group 1 allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR SO_2 Group 1 unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before May 1 of the first control period for which TR SO_2 Group 1 allowances are sought and after the date on which the TR SO_2 Group 1 unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR SO_2 Group 1 allowances in an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(3) The Administrator will review each TR SO_2 Group 1 allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR SO_2 Group 1 allowances for each control period pursuant to an accepted request as follows:

(i) After May 1 of such control period, the Administrator will determine the sum of the TR SO_2 Group 1 allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR SO_2 Group 1 allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR SO_2 Group 1 allowances requested to each TR SO_2 Group 1 unit covered by an accepted allowance allocation request.

(iii) If the amount of TR SO_2 Group 1 allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR SO_2 Group 1 unit covered by an accepted allowance allocation request the amount of the TR SO_2 Group 1 allowances requested, multiplied by the amount of TR SO_2 Group 1 allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.611(b), each designated representative that submitted an allowance allocation request of the amount of TR SO_2 Group 1 allowances (if any) allocated for such control period to the TR SO_2 Group 1 unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR SO_2 Group 1 allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR SO_2 Group 1 unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR SO_2 Group 1 allowances for such control period in accordance with § 97.611(a)(2), an amount of TR SO_2 Group 1 allowances equal to the following: The total amount of such remaining unallocated TR SO_2 Group 1 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.611(a) for such control period, divided by the remainder of the amount of tons in the applicable State SO_2 Group 1 trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.613 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.615, each TR SO_2 Group 1 source, including all TR SO_2 Group 1 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO_2 Group 1 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 1 units at the source and shall act in accordance with the certification statement in § 97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.616:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO_2 Group 1 unit at the source in all matters pertaining to the TR SO_2 Group 1 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.615, each TR SO_2 Group 1 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 1 units at the source and shall act in accordance with the certification statement in § 97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.616,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action,

inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit. (c) Except in this section, § 97.602, and §§ 97.614 through 97.618, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.614 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.618 concerning delegation of authority to make submissions, each submission under the TR SO_2 Group 1 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO_2 Group 1 source and TR SO_2 Group 1 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.618.

§ 97.615 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO_2 Group 1 source and the TR SO_2 Group 1 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO_2 Group 1 source and the TR SO_2 Group 1 units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit is not included in the list of owners and operators in the certificate of representation under § 97.616, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.616 amending the list of owners and operators to include the change.

§ 97.616 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR SO_2 Group 1 source, and each TR SO_2 Group 1 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR SO_2 Group 1 source and of each TR SO_2 Group 1 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR SO_2 Group 1 unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 1 Trading Program on behalf of the owners and operators of the source and of each TR SO_2 Group 1 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR SO_2 Group 1 unit, or where a utility or industrial customer purchases power from a TR SO_2 Group 1 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR SO_2 Group 1 unit at the source; and TR SO_2 Group 1 allowances and proceeds of transactions involving TR SO_2 Group 1 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR SO_2 Group 1 allowances by contract, TR SO_2 Group 1 allowances and proceeds of transactions involving TR SO_2 Group 1 allowances will be deemed to be held or

distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.617 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.616 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.616 is received by the Administrator.

(b) Except as provided in § 97.615(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 1 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO_2 Group 1 allowance transfers.

§ 97.618 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.618 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.619 [Reserved]

§ 97.620 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.616, the Administrator will establish a compliance account for the TR SO_2 Group 1 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO_2 Group 1 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to

represent their ownership interest with respect to the TR SO_2 Group 1 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 1 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account in all matters pertaining to the TR SO_2 Group 1 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account. (ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR SO_2 Group 1 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR SO_2 Group 1 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to SO_2 Group 1 allowances in the general account, including the addition of a new person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any

representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 1 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO_2 Group 1 allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.620(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR SO_2 Group 1 allowance transfer under § 97.622 for any TR SO_2 Group 1 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR SO_2 Group 1 allowance transfers to or from the account for a 12-month period or longer and does not contain any TR SO_2 Group 1 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted TR SO_2 Group 1 allowance transfer under § 97.622 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR SO_2 Group 1 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.614(a) and 97.618 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.621 Recordation of TR SO_2 Group 1 allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated for the TR SO_2 Group 1 units at the source in accordance with §§ 97.611(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated for the TR SO_2 Group 1 units at the source in accordance with § 97.611(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By September 1, 2012 and September 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated for the TR SO_2 Group 1 units at the source in accordance with § 97.612 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR SO_2 Group 1 allowances for a TR

SO_2 Group 1 unit in a compliance account, the Administrator will assign each TR SO_2 Group 1 allowance a unique identification number that will include digits identifying the year of the control period for which the TR SO_2 Group 1 allowance is allocated.

§ 97.622 Submission of TR SO_2 Group 1 allowance transfers.

(a) An authorized account representative seeking recordation of a TR SO_2 Group 1 allowance transfer shall submit the transfer to the Administrator.

(b) A TR SO_2 Group 1 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR SO_2 Group 1 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR SO_2 Group 1 allowance identified by serial number in the transfer.

§ 97.623 Recordation of TR SO_2 Group 1 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR SO_2 Group 1 allowance transfer, the Administrator will record a TR SO_2 Group 1 allowance transfer by moving each TR SO_2 Group 1 allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.622.

(b)(1) A TR SO_2 Group 1 allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR SO_2 Group 1 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.624 for the control period immediately before such allowance transfer deadline.

(2) A TR SO_2 Group 1 allowance transfer that is submitted for recordation after the deadline for holding TR SO_2 Group 1 allowances described in § 97.625(b)(5) and that includes any TR SO_2 Group 1 allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.625 for the control period immediately before the year of such deadline.

(c) Where a TR SO_2 Group 1 allowance transfer is not correctly submitted under § 97.622, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR SO_2 Group 1 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR SO_2 Group 1 allowance transfer that is not correctly submitted under § 97.622, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.624 Compliance with TR SO_2 Group 1 emissions limitation.

(a) *Availability for deduction for compliance.* TR SO_2 Group 1 allowances are available to be deducted for compliance with a source's TR SO_2 Group 1 emissions limitation for a control period in a given year only if the TR SO_2 Group 1 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.623, of TR SO_2 Group 1 allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR SO_2 Group 1 allowances available under paragraph (a) of this section in order to determine whether the source meets the TR SO_2 Group 1 emissions limitation for such control period, as follows:

(1) Until the amount of TR SO_2 Group 1 allowances deducted equals the number of tons of total SO_2 emissions from all TR SO_2 Group 1 units at the source for such control period; or

(2) If there are insufficient TR SO_2 Group 1 allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR SO_2 Group 1 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR SO_2 Group 1 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR SO_2 Group 1 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR SO_2 Group 1 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 1 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 1 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 1 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 1 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR SO_2 Group 1 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR SO_2 Group 1 allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.625 Compliance with TR SO_2 Group 1 assurance provisions.

(a) *Availability for deduction.* TR SO_2 Group 1 allowances are available to be deducted for compliance with the TR SO_2 Group 1 assurance provisions for a control period in a given year by an owner of one or more TR SO_2 Group 1 units in a State only if the TR SO_2 Group 1 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance

with paragraph (b)(4)(ii) of this section, of one of the owner's TR SO_2 Group 1 sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR SO_2 Group 1 allowances available under paragraph (a) of this section for compliance with the TR SO_2 Group 1 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of SO_2 emissions from all TR SO_2 Group 1 units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.606(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO_2 emissions for each TR SO_2 Group 1 unit and of the amounts described in §§ 97.606(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR SO_2 Group 1 unit and each State for the control period in the year involved are in accordance with § 97.606(c)(2)(iii) and §§ 97.606(b) and 97.630 through 97.635.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By August 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR SO_2 Group 1 sources with total SO_2 emissions exceeding the State assurance level for a control period, as described in § 97.606(c)(2)(iii):

(i) By August 15 immediately after the promulgation of such notice, the designated representative of each TR SO_2 Group 1 source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR SO_2 Group 1 unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.602, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR SO_2 Group 1 unit at the source that operates during, but is allocated no TR SO_2 Group 1 allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable SO_2 emission rate for such control period.

(ii) By September 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR SO_2 Group 1 units in the State and for the control period in the year involved, each owner's share of the total SO_2 emissions from all TR SO_2 Group 1 units in the State, each owner's assurance level, and the amount (if any) of TR SO_2 Group 1 allowances that each owner must hold in accordance with the calculation formula in § 97.606(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the SO_2 emissions for the relevant TR SO_2 Group 1 units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.602, and the calculation formula in § 97.606(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section. By November 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By December 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR SO_2 Group 1 units in a State and as being required to hold TR SO_2 Group 1 allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR SO_2 Group 1 allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of December 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR SO_2 Group 1 allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if December 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After December 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.623, of TR SO_2 Group 1 allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR SO_2 Group 1 allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR SO_2 Group 1 allowances deducted equals the

amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR SO_2 Group 1 allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR SO_2 Group 1 allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR SO_2 Group 1 allowances that each owner is required to hold in accordance with § 97.606(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 1 allowances that owners are required to hold in accordance with the calculation formula in § 97.606(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 1 allowances that owners are required to hold in accordance with the calculation formula in § 97.606(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR SO_2 Group 1 allowances that an owner is required to hold for the control period in the year involved with regard to the State involved—

(A) Where the amount of TR SO_2 Group 1 allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR SO_2 Group 1 allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR SO_2 Group 1 allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR SO_2 Group 1 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR SO_2 Group 1 allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance account) for the control period in the year involved.

(C) Each TR SO_2 Group 1 allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements under the TR SO_2 Group 1 assurance provisions for a control period in a given year must be a TR SO_2 Group 1 allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR SO_2 Group 1 allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR SO_2 Group 1 allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 1 allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 1 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 1 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 1 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.626 Banking.

(a) A TR SO_2 Group 1 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR SO_2 Group 1 allowance that is held in a compliance account or a general account will remain in such

account unless and until the TR SO_2 Group 1 allowance is deducted or transferred under § 97.611(c), § 97.623, § 97.624, § 97.625, 97.627, 97.628, 97.642, or 97.643.

§ 97.627 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.628 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO_2 Group 1 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR SO_2 Group 1 allowances from or transfer TR SO_2 Group 1 allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.629 [Reserved]

§ 97.630 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO_2 Group 1 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.602 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR SO_2 Group 1 unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.602, and the term "newly affected unit" shall be deemed to mean "newly affected TR SO_2 Group 1 unit." The owner or operator of a unit that is not a TR SO_2 Group 1 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO_2 Group 1 unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR SO_2 Group 1 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 97.631 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO_2 Group 1 unit that commences commercial operation before July 1, 2011, by January 1, 2012.

(2) For the owner or operator of a TR SO_2 Group 1 unit that commences commercial operation on or after July 1, 2011, by the later of the following dates:

(i) January 1, 2012; or

(ii) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a TR SO_2 Group 1 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO_2 emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.641(c).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a TR SO_2 Group 1 opt-in unit, by the date on which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program as provided in § 97.641(h).

(c) *Reporting data.* The owner or operator of a TR SO_2 Group 1 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR SO_2 Group 1 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.635.

(2) No owner or operator of a TR SO_2 Group 1 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR SO_2 Group 1 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR SO_2 Group 1 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.605 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same

pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.631(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR SO_2 Group 1 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.631 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO_2 Group 1 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.630(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.630(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO_2 Group 1 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 97.630(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.630(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.630(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.630(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 97.630(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.630(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.633.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO_2 Group 1 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR SO_2 Group 1 Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day

review period specified in paragraph (d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.632(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.632 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.631 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.631 for each disapproved monitoring system.

§ 97.633 Notifications concerning monitoring.

The designated representative of a TR SO_2 Group 1 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.634 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 97.614(a).

(b) *Monitoring plans.* The owner or operator of a TR SO_2 Group 1 unit shall comply with requirements of § 75.62 of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.631, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for the TR SO_2 Group 1 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.630(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall

commence in the quarter covering January 1, 2012 through March 31, 2012;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.641(c); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a TR SO_2 Group 1 opt-in unit, the calendar quarter corresponding to the date on which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program as provided in § 97.641(h).

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For TR SO_2 Group 1 units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 97.635 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO_2 Group 1 unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.630 through 97.634 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.602.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.640 General requirements for TR SO_2 Group 1 opt-in units.

(a) A TR SO_2 Group 1 opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR SO_2 Group 1 unit under § 97.604;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR SO_2 Group 1 opt-in unit shall be deemed to be a TR SO_2 Group 1 unit for purposes of applying this subpart, except for §§ 97.605, 97.611, and 97.612.

(c) Solely for purposes of applying the requirements of §§ 97.613 through 97.618 and §§ 97.630 through 97.635, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.642 shall be deemed to be a TR SO_2 Group 1 unit.

(d) Any TR SO_2 Group 1 opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.642, located at the same source as one or more TR SO_2 Group 1 units shall have the same designated representative and alternate designated representative as such TR SO_2 Group 1 units.

§ 97.641 Opt-in process.

A unit meeting the requirements for a TR SO_2 Group 1 opt-in unit in § 97.640(a) may become a TR SO_2 Group 1 opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt-in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.642(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located,

including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR SO_2 Group 1 unit under § 97.604;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.630 through 97.635;

(4) A statement that the unit, if approved to become a TR SO_2 Group 1 unit under paragraph (g) of this section, may withdraw from the TR SO_2 Group 1 Trading Program only in accordance with § 97.642;

(5) A statement that the unit, if approved to become a TR SO_2 Group 1 unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.643;

(6) A complete certificate of representation under § 97.616 consistent with § 97.640, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) *Interim review of monitoring plan.* The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO_2 emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.630 through 97.635. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) *Monitoring and reporting.* (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the SO_2 emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.630 through 97.635, starting on the date of certification of the necessary monitoring systems under §§ 97.630 through 97.635 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR SO_2 Group 1 Trading Program in accordance with § 97.642.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR SO_2 Group 1 Trading Program under paragraph (h) of this section, during which period monitoring system availability must not be less than 98 percent under §§ 97.630 through 97.635 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the SO_2 emission rate and the heat input of the unit are monitored and reported in accordance with §§ 97.630 through 97.635 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.630 through 97.635 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR SO_2 Group 1 Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline SO_2 emission rate.* The unit's baseline SO_2 emission rate shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's SO_2 emission rate (in lb/mmBtu) for such control period;

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods during which the unit has add-on SO_2 emission controls.

(g) *Review of TR opt-in application.*

(1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR SO_2 Group 1 opt-in unit in § 97.640, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approve will state the unit's baseline heat input and baseline SO_2 emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR SO_2 Group 1 opt-in unit in § 97.640, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) *Date of entry into TR SO_2 Group 1 Trading Program.* A unit for which a

TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR SO_2 Group 1 opt-in unit, and a TR SO_2 Group 1 unit, effective as of the later of January 1, 2012, or January 1 of the first control period during which such approval is issued.

§ 97.642 Withdrawal of TR SO_2 Group 1 opt-in unit from TR SO_2 Group 1 Trading Program.

A TR SO_2 Group 1 opt-in unit may withdraw from the TR SO_2 Group 1 Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR SO_2 Group 1 opt-in unit from the TR SO_2 Group 1 Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of the unit's entry into the TR SO_2 Group 1 Trading Program under § 97.641(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR SO_2 Group 1 opt-in unit covered by the request to withdraw may withdraw from the TR SO_2 Group 1 Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR SO_2 Group 1 opt-in unit must meet the requirement to hold TR SO_2 Group 1 allowances under §§ 97.624 and 97.625 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit TR SO_2 Group 1 allowances equal in amount to and allocated for the same or a prior control period as any TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under § 97.644 for any control period after the date on which the withdrawal is to be effective. If there are no other TR SO_2 Group 1 units at the source, the Administrator will close the compliance account, and the owners and operators of the TR SO_2 Group 1 opt-in unit may submit a TR SO_2 Group 1 allowance transfer for any remaining TR SO_2 Group 1 allowances to another Allowance Management System account in accordance with §§ 97.622 and 97.623.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR SO_2 Group 1 allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on December 31 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR SO_2 Group 1 opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR SO_2 Group 1 Trading Program concerning any control periods for which the unit is a TR SO_2 Group 1 opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR SO_2 Group 1 opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR SO_2 Group 1 Trading Program.* Once a TR SO_2 Group 1 opt-in unit withdraws from the TR SO_2 Group 1 Trading Program, the designated representative may not submit another opt-in application under § 97.641 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.643 Change in regulatory status.

(a) *Notification.* If a TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR SO_2 Group 1 opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, the Administrator will deduct, from the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit that becomes a TR SO_2 Group 1 unit under § 97.604, TR SO_2 Group 1 allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under § 97.644 for any control period starting after the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604; and

(ii) If the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604 is not December 31, the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under § 97.644 for the control period that includes the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit that becomes a TR SO_2 Group 1 unit under § 97.604 contains the TR SO_2 Group 1 allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, the TR SO_2 Group 1 opt-in unit will be allocated TR SO_2 Group 1 allowances in accordance with § 97.612.

(ii) If the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604 is not December 31, the following amount of TR SO_2 Group 1 allowances will be allocated to the TR SO_2 Group 1 opt-in unit (as a TR SO_2 Group 1 unit) in accordance with § 97.612 for the control period that includes the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604:

(A) The amount of TR SO_2 Group 1 allowances otherwise allocated to the TR SO_2 Group 1 opt-in unit (as a TR SO_2 Group 1 unit) in accordance with § 97.612 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, divided by the total number of days in the control period; and

(C) Rounded to the nearest allowance.

§ 97.644 TR SO_2 Group 1 allowance allocations to TR SO_2 Group 1 opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.641(g), the Administrator will issue TR SO_2 Group 1 allowances and allocate them to the unit for the control period in which the unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h), in accordance with paragraph (b) of this section.

(2) By no later than October 31 of the control period after the control period in which a TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h) and October 31 of each year thereafter, the Administrator will issue TR SO_2 Group 1 allowances and allocate them to the TR SO_2 Group 1 opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR SO_2 Group 1 opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR SO_2 Group 1 opt-in unit is to be allocated TR SO_2 Group 1 allowances, the Administrator will issue and allocate TR SO_2 Group 1 allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR SO_2 Group 1 allowance allocation will be the lesser of:

(i) The TR SO_2 Group 1 opt-in unit's baseline heat input determined under § 97.641(g); or

(ii) The TR SO_2 Group 1 opt-in unit's heat input, as determined in accordance with §§ 97.630 through 97.635, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h).

(2) The SO_2 emission rate (in lb/mmBtu) used for calculating TR SO_2 Group 1 allowance allocations will be the lesser of:

(i) The TR SO_2 Group 1 opt-in unit's baseline SO_2 emission rate (in lb/mmBtu) determined under § 97.641(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO_2 emissions limitation applicable to the TR SO_2 Group 1 opt-in unit at any time during the control period for which TR SO_2 Group 1 allowances are to be allocated.

(3) The Administrator will issue TR SO_2 Group 1 allowances and allocate them to the TR SO_2 Group 1 opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the SO_2 emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit, the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period after the control period in which a TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit, the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under paragraph (a)(2) of this section.

38. Part 97 is amended by adding subpart DDDDD to read as follows:

Subpart DDDDD—TR SO_2 Group 2 Trading Program

Sec.

Subpart DDDDD—TR SO_2 Group 2 Trading Program

§ 97.701 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO_2 Group 2 Trading Program, under section 110 of the Clean Air Act and § 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.702 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR SO_2 Group 2 allowances, the determination by the Administrator of the amount of such TR SO_2 Group 2 allowances to be initially credited to a TR SO_2 Group 2 source or a new unit set-aside.

Allowable SO_2 emission rate means, with regard to a unit, the SO_2 emission rate limit that is applicable to the unit

and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR SO_2 Group 2 allowances under the TR SO_2 Group 2 Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR SO_2 Group 2 allowances and data related to SO_2 emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO_2 Group 2 allowances.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 2 allowance transfer must be submitted for recordation in a TR SO_2 Group 2 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 2 Annual emissions limitation for such control period in accordance with § 97.724.

Alternate designated representative means, for a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO_2 Group 2 Trading Program. If the TR SO_2 Group 2 source is also subject to the Acid Rain Program, TR NO_X Annual Season Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR SO_2 Group 2 allowances held in the general account and, with regard to a TR SO_2 Group 2 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated

duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 97.705.

(i) For a unit that is a TR SO_2 Group 2 unit under § 97.704 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO_2 Group 2 unit under § 97.704 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.705, for a unit that is not a TR SO_2 Group 2 unit under § 97.704 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR SO_2 Group 2 unit under § 97.704.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR SO_2 Group 2 source under this subpart, in which any TR SO_2 Group 2 allowance allocations for the TR SO_2 Group 2 units at the source are recorded and in which are held any TR SO_2 Group 2 allowances available for use for a control period in complying with the source's TR SO_2 Group 2 emissions limitation in accordance with § 97.724 and the TR SO_2 Group 2 assurance provisions in accordance with § 97.725.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.730 through 97.735. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO_2 monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.706(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO_2 Group 2 Trading Program. If the TR SO_2 Group 2 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of SO_2 emitted from the TR SO_2 Group 2 units at a TR SO_2 Group 2 source during a control period that exceeds the TR SO_2 Group 2 emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.704(b)(2)(i)(B), 97.704(b)(2)(ii)(B), and 97.704(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR SO_2 Group 2 unit means a unit that was not a TR SO_2 Group 2 unit when it began operating but that thereafter becomes a TR SO_2 Group 2 unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR SO_2 Group 2 unit or a TR SO_2 Group 2 source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit;

(2) Any holder of a leasehold interest in a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit, provided that, unless expressly provided for in a leasehold agreement, "owner" shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR SO_2 Group 2 unit;

(3) Any purchaser of power from a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR SO_2 Group 2 assurance provisions in §§ 97.706(c)(2) and 97.725, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR SO_2 Group 2 units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.706(c)(2)(iii)(A) and not as described in § 97.706(c)(2)(iii)(B), the owner's share of the State SO_2 Group 2 trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.706(c)(2)(iii)(B), the owner's share of the State SO_2 Group 2 trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period, the total tonnage of SO_2 emissions during such control period from all of the owner's TR SO_2 Group 2 units in the State;

(2) With regard to a State SO_2 Group 2 trading budget with a one-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 2 allowances allocated for such control period to all of the owner's TR SO_2 Group 2 units in the State, multiplied by the sum of the State SO_2 Group 2 trading budget under § 97.710(a) and the State's one-year variability limit under § 97.710(b) and divided by such State SO_2 Group 2 trading budget;

(3) With regard to a State SO_2 Group 2 trading budget with a three-year

variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 2 allowances allocated for such control period to all of the owner's TR SO_2 Group 2 units in the State, multiplied by the sum of the State SO_2 Group 2 trading budget under § 97.710(a) and the State's three-year variability limit under § 97.710(b) and divided by such State SO_2 Group 2 trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of SO_2 emissions and of TR SO_2 Group 2 allowances allocated for a control period, with regard to such unit, used in determining each owner's share shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's SO_2 emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of December 31 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which SO_2 mass emissions are reported for a control period for a year, the amount of tonnage of each unit's SO_2 emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of SO_2 emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be *de minimis;* or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.735; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR SO_2 Group 2 allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO_2 Group 2 allowances for such control period equal to the lesser of—

(i) The unit's allowable SO_2 emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.84 (if the unit is a coal-fired boiler), 0.15 (if the unit is a simple combustion turbine), or 0.66 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's SO_2 emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR SO_2 Group 2 allowances, the moving of TR SO_2 Group 2 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR SO_2 Group 2 allowance, the unique identification number assigned to each TR SO_2 Group 2 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source", "stationary source", or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR SO_2 Group 2 Trading Program pursuant to § 52.38(c) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55 (W + 9H)$$

Where

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in

accordance with subpart AAAAA and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart BBBBB of this part and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 2 allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of SO_2 during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR SO_2 Group 2 Trading Program.

TR SO_2 Group 2 allowance deduction or *deduct TR SO_2 Group 2 allowances* means the permanent withdrawal of TR SO_2 Group 2 allowances by the Administrator from a compliance account, *e.g.,* in order to account for compliance with the TR SO_2 Group 2 emissions limitation or assurance provisions.

TR SO_2 Group 2 allowances held or *hold TR SO_2 Group 2 allowances* means the TR SO_2 Group 2 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR SO_2 Group 2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR SO_2 Group 2 allowance transfer in accordance with this subpart.

TR SO_2 Group 2 emissions limitation means, for a TR SO_2 Group 2 source, the tonnage of SO_2 emissions authorized in a control period by the TR SO_2 Group 2 allowances available for deduction for the source under § 97.724(a) for such control period.

TR SO_2 Group 2 source means a source that includes one or more TR SO_2 Group 2 units.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.38(c) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 unit means a unit that is subject to the TR SO_2 Group 2 Trading Program under § 97.704.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.703 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.704 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR SO_2 Group 2 units, and any source that includes one or more such units shall be a TR SO_2 Group 2 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO_2 Group 2 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO_2 Group 2 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR SO_2 Group 2 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR SO_2 Group 2 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu

basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 2 Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 2 Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.705 Retired unit exemption.

(a)(1) Any TR SO_2 Group 2 unit that is permanently retired and is not a TR SO_2 Group 2 opt-in unit shall be exempt from § 97.706(b) and (c)(1), § 97.724, and §§ 97.730 through 97.735.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO_2 Group 2 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.706 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.713 through 97.718.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.730 through 97.735.

(2) The emissions data determined in accordance with §§ 97.730 through 97.735 shall be used to calculate allocations of TR SO_2 Group 2 allowances under §§ 97.711(a)(2) and (b) and 97.712 and to determine compliance with the TR SO_2 Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.730 through 97.735 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *SO_2 emissions requirements.* (1) TR SO_2 Group 2 emissions limitation. (i) As of the allowance transfer deadline for a control period, the owners and operators of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 2 allowances available for deduction for such control period under § 97.724(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 2 units at the source.

(ii) If a TR SO_2 Group 2 source emits SO_2 during any control period in excess of the TR SO_2 Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall hold the TR SO_2 Group 2 allowances required for deduction under § 97.724(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) *TR SO_2 Group 2 assurance provisions.* (i) If the total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such SO_2 emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.725(b)(4)(ii), TR SO_2 Group 2 allowances available for deduction for such control period under § 97.725(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.725(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such SO_2 emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such SO_2 emissions exceeds that owner's assurance level; and

(B) The amount by which total SO_2 emissions for all TR SO_2 Group 2 units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR SO_2 Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) The total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of SO_2 emissions exceeds the sum, for such control period, of the State SO_2 Group 2 trading budget and the State's one-year variability limit under § 97.710(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of SO_2 emissions and the total amounts of SO_2 emissions from all TR SO_2 Group 2 units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State SO_2 Group 2 trading budget and the State's three-year variability limit under § 97.710(b);

(C) Provided that the amount by which such total amount of SO_2 emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period exceeds the State assurance level or if an owner's share of total SO_2 emissions from the TR SO_2 Group 2 units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR SO_2 Group 2 allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO_2 Group 2 allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR SO_2 Group 2 unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.730(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.730(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR SO_2 Group 2 allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR SO_2 Group 2 allowance was allocated.

(5) *Allowance Management System requirements.* Each TR SO_2 Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR SO_2 Group 2 allowance is a limited authorization to emit one ton of SO_2 in accordance with the TR SO_2 Group 2 Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR SO_2 Group 2 allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under §§ 75.10, 75.11, and 75.16 of this chapter), an excepted monitoring system (under appendix D to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.730 through 97.735 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a

period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.716 for the designated representative for the source and each TR SO_2 Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 97.716 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 2 Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall make all submissions required under the TR SO_2 Group 2 Trading Program, including any submissions required for compliance with the TR SO_2 Group 2 assurance provisions. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR SO_2 Group 2 Trading Program that applies to a TR SO_2 Group 2 source or the designated representative of a TR SO_2 Group 2 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 2 units at the source.

(2) Any provision of the TR SO_2 Group 2 Trading Program that applies to a TR SO_2 Group 2 unit or the designated representative of a TR SO_2 Group 2 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR SO_2 Group 2 Trading Program or exemption under § 97.705 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 2 source or TR SO_2 Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.707 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR SO_2 Group 2 Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.708 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO_2 Group 2 Trading Program are set forth in part 78 of this chapter.

§ 97.709 [Reserved]

§ 97.710 State SO_2 Group 2 trading budgets, new-unit set-asides, and variability limits.

(a) The State SO_2 Group 2 trading budgets and new-unit set-asides for allocations of TR SO_2 Group 2 allowances for the control periods in 2012 and thereafter are as follows:

State	SO_2 group 2 trading budget (tons) *	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Alabama	161,871	4,856
Connecticut	3,059	92
Delaware	7,784	234
District of Columbia	337	10
Florida	161,739	4,852
Kansas	57,275	1,718
Louisiana	90,477	2,714
Maryland	39,665	1,190
Massachusetts	7,902	237
Minnesota	47,101	1,413
Nebraska	71,598	2,148
New Jersey	11,291	339
South Carolina	116,483	3,494
Total	776,582	23,297

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State SO_2 Group 2 trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Alabama	16,187	9,346
Connecticut	1,700	981
Delaware	1,700	981
District of Columbia	1,700	981
Florida	16,174	9,338
Kansas	5,728	3,307
Louisiana	9,048	5,224
Maryland	3,967	2,290
Massachusetts	1,700	981
Minnesota	4,710	2,719
Nebraska	7,160	4,134
New Jersey	1,700	981
South Carolina	11,648	6,725

§ 97.711 Timing requirements for TR SO_2 Group 2 allowance allocations.

(a) *Existing units.* (1) TR SO_2 Group 2 allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR SO_2 Group 2 unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR SO_2 Group 2 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR SO_2 Group 2 allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR SO_2 Group 2 allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR SO_2 Group 2 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO_2 Group 2 allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By July 1, 2012, and July 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 2 allowance allocation for each TR SO_2 Group 2 unit, in accordance with § 97.712, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.712 and §§ 97.706(b)(2) and 97.730 through 97.735.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By September 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR SO_2 Group 2 units.* For each control period in 2012 and thereafter, if the Administrator determines that TR SO_2 Group 2 allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR SO_2 Group 2 unit under § 97.704 as of January 1, 2012, or whose deadline for meeting monitor certification requirements under § 97.730(b)(1) and (2) is after January 1, 2012, or if the Administrator determines that TR SO_2 Group 2 allowances were allocated under paragraph (b) of this section and § 97.712 for the control period to a recipient that is not actually a TR SO_2 Group 2 unit under § 97.704 as of January 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR SO_2 Group 2 allowances under § 97.721.

(2) If the Administrator already recorded such TR SO_2 Group 2 allowances under § 97.721 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.724(b) for such control period, then the Administrator will deduct from the account in which such TR SO_2 Group 2 allowances were recorded an amount of TR SO_2 Group 2 allowances allocated for the same or a prior control period equal to the amount of such already recorded TR SO_2 Group 2 allowances. The authorized account representative shall ensure that there are sufficient TR SO_2 Group 2 allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR SO_2 Group 2 allowances under § 97.721 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.724(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO_2 Group 2 allowances.

(4) The Administrator will transfer the TR SO_2 Group 2 allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, such notice has been promulgated, in the next year.

§ 97.712 TR SO_2 Group 2 allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR SO_2 Group 2 allowances to TR SO_2 Group 2 units in a State that are not listed in appendix A to this subpart, to TR SO_2 Group 2 units that are so listed and whose allocation of SO_2 Group 2 allowances for such control period is covered by § 97.711(c)(1) or (2), and to TR SO_2 Group 2 units that are so listed and, pursuant to § 97.711(a)(2), are not allocated TR SO_2 Group 2 allowances for such control period but that operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR SO_2 Group 2 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.710(a). Each new unit set-aside will be allocated additional TR SO_2 Group 2 allowances in accordance with § 97.711(a)(2) and (c)(4).

(2) The designated representative of such TR SO_2 Group 2 unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR SO_2 Group 2 allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR SO_2 Group 2 unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before May 1 of the first control period for which TR SO_2 Group 2 allowances are sought and after the date on which the TR SO_2 Group 2 unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR SO_2 Group 2 allowances in an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(3) The Administrator will review each TR SO_2 Group 2 allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR SO_2 Group 2 allowances for each control period pursuant to an accepted request as follows:

(i) After May 1 of such control period, the Administrator will determine the sum of the TR SO_2 Group 2 allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR SO_2 Group 2 allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR SO_2 Group 2 allowances requested to each TR SO_2 Group 2 unit covered by an accepted allowance allocation request.

(iii) If the amount of TR SO_2 Group 2 allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR SO_2 Group 2 unit covered by an accepted allowance allocation request the amount of the TR SO_2 Group 2 allowances requested, multiplied by the amount of TR SO_2 Group 2 allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.711(b), each designated representative that submitted an allowance allocation request of the amount of TR SO_2 Group 2 allowances (if any) allocated for such control period to the TR SO_2 Group 2 unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR SO_2 Group 2 allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR SO_2 Group 2 unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR SO_2 Group 2 allowances for such control period in accordance with § 97.711(a)(2), an amount of TR SO_2 Group 2 allowances equal to the following: The total amount of such remaining unallocated TR SO_2 Group 2 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.711(a) for such control period, divided by the remainder of the amount of tons in the applicable State SO_2 Group 2 trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.713 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.715, each TR SO_2 Group 2 source, including all TR SO_2 Group 2 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO_2 Group 2 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 2 units at the source and shall act in accordance with the certification statement in § 97.716(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.716:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO_2 Group 2 unit at the source in all matters pertaining to the TR SO_2 Group 2 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.715, each TR SO_2 Group 2 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 2 units at the source and shall act in accordance with the certification statement in § 97.716(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.716,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action,

inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.702, and §§ 97.714 through 97.718, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.714 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.718 concerning delegation of authority to make submissions, each submission under the TR SO_2 Group 2 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO_2 Group 2 source and TR SO_2 Group 2 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.718.

§ 97.715 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO_2 Group 2 source and the TR SO_2 Group 2 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO_2 Group 2 source and the TR SO_2 Group 2 units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit is not included in the list of owners and operators in the certificate of representation under § 97.716, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.716 amending the list of owners and operators to include the change.

§ 97.716 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR SO_2 Group 2 source, and each TR SO_2 Group 2 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR SO_2 Group 2 source and of each TR SO_2 Group 2 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR SO_2 Group 2 unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 2 Trading Program on behalf of the owners and operators of the source and of each TR SO_2 Group 2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR SO_2 Group 2 unit, or where a utility or industrial customer purchases power from a TR SO_2 Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR SO_2 Group 2 unit at the source; and TR SO_2 Group 2 allowances and proceeds of transactions involving TR SO_2 Group 2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR SO_2 Group 2 allowances by contract, TR SO_2 Group 2 allowances and proceeds of transactions involving TR SO_2 Group 2

allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.717 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.716 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.716 is received by the Administrator.

(b) Except as provided in § 97.715(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 2 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO_2 Group 2 allowance transfers.

§ 97.718 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.718(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.718(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.718 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.719 [Reserved]

§ 97.720 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.716, the Administrator will establish a compliance account for the TR SO_2 Group 2 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO_2 Group 2 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to

represent their ownership interest with respect to the TR SO_2 Group 2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account in all matters pertaining to the TR SO_2 Group 2 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR SO_2 Group 2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR SO_2 Group 2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to SO_2 Group 2 allowances in the general account, including the addition of a new person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any

representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO_2 Group 2 allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.720(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR SO_2 Group 2 allowance transfer under § 97.722 for any TR SO_2 Group 2 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR SO_2 Group 2 allowance transfers to or from the account for a 12-month period or longer and does not contain any TR SO_2 Group 2 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted TR SO_2 Group 2 allowance transfer under § 97.722 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR SO_2 Group 2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.714(a) and 97.718 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.721 Recordation of TR SO_2 Group 2 allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated for the TR SO_2 Group 2 units at the source in accordance with §§ 97.711(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated for the TR SO_2 Group 2 units at the source in accordance with § 97.711(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By September 1, 2012 and September 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated for the TR SO_2 Group 2 units at the source in accordance with § 97.712 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR SO_2 Group 2 allowances for a TR SO_2 Group 2 unit in a compliance

account, the Administrator will assign each TR SO_2 Group 2 allowance a unique identification number that will include digits identifying the year of the control period for which the TR SO_2 Group 2 allowance is allocated.

§ 97.722 Submission of TR SO_2 Group 2 allowance transfers.

(a) An authorized account representative seeking recordation of a TR SO_2 Group 2 allowance transfer shall submit the transfer to the Administrator.

(b) A TR SO_2 Group 2 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR SO_2 Group 2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR SO_2 Group 2 allowance identified by serial number in the transfer.

§ 97.723 Recordation of TR SO_2 Group 2 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR SO_2 Group 2 allowance transfer, the Administrator will record a TR SO_2 Group 2 allowance transfer by moving each TR SO_2 Group 2 allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.722.

(b)(1) A TR SO_2 Group 2 allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR SO_2 Group 2 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.724 for the control period immediately before such allowance transfer deadline.

(2) A TR SO_2 Group 2 allowance transfer that is submitted for recordation after the deadline for holding TR SO_2 Group 2 allowances described in § 97.725(b)(5) and that includes any TR SO_2 Group 2 allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.725 for the control period immediately before the year of such deadline.

(c) Where a TR SO_2 Group 2 allowance transfer is not correctly submitted under § 97.722, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR SO_2 Group 2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR SO_2 Group 2 allowance transfer that is not correctly submitted under § 97.722, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.724 Compliance with TR SO_2 Group 2 emissions limitation.

(a) *Availability for deduction for compliance.* TR SO_2 Group 2 allowances are available to be deducted for compliance with a source's TR SO_2 Group 2 emissions limitation for a control period in a given year only if the TR SO_2 Group 2 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.723, of TR SO_2 Group 2 allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR SO_2 Group 2 allowances available under paragraph (a) of this section in order to determine whether the source meets the TR SO_2 Group 2 emissions limitation for such control period, as follows:

(1) Until the amount of TR SO_2 Group 2 allowances deducted equals the number of tons of total SO_2 emissions from all TR SO_2 Group 2 units at the source for such control period; or

(2) If there are insufficient TR SO_2 Group 2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR SO_2 Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR* SO_2 *Group 2 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR SO_2 Group 2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR SO_2 Group 2 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 2 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 2 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 2 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 2 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR SO_2 Group 2 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR SO_2 Group 2 allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.725 Compliance with TR SO_2 Group 2 assurance provisions.

(a) *Availability for deduction.* TR SO_2 Group 2 allowances are available to be deducted for compliance with the TR SO_2 Group 2 assurance provisions for a control period in a given year by an owner of one or more TR SO_2 Group 2 units in a State only if the TR SO_2 Group 2 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance with paragraph (b)(4)(ii) of this section,

of one of the owner's TR SO_2 Group 2 sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR SO_2 Group 2 allowances available under paragraph (a) of this section for compliance with the TR SO_2 Group 2 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of SO_2 emissions from all TR SO_2 Group 2 units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.706(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO_2 emissions for each TR SO_2 Group 2 unit and of the amounts described in §§ 97.706(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR SO_2 Group 2 unit and each State for the control period in the year involved are in accordance with § 97.706(c)(2)(iii) and §§ 97.706(b) and 97.730 through 97.735.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By August 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR SO_2 Group 2 sources with total SO_2 emissions exceeding the State assurance level for a control period, as described in § 97.706(c)(2)(iii):

(i) By August 15 immediately after the promulgation of such notice, the designated representative of each TR SO_2 Group 2 source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR SO_2 Group 2 unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.702, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR SO_2 Group 2 unit at the source that operates during, but is allocated no TR SO_2 Group 2 allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable SO_2 emission rate for such control period.

(ii) By September 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR SO_2 Group 2 units in the State and for the control period in the year involved, each owner's share of the total SO_2 emissions from all TR SO_2 Group 2 units in the State, each owner's assurance level, and the amount (if any) of TR SO_2 Group 2 allowances that each owner must hold in accordance with the calculation formula in § 97.706(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the SO_2 emissions for the relevant TR SO_2 Group 2 units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.702, and the calculation formula in § 97.706(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section. By November 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By December 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR SO_2 Group 2 units in a State and as being required to hold TR SO_2 Group 2 allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR SO_2 Group 2 allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of December 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR SO_2 Group 2 allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if December 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After December 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.723, of TR SO_2 Group 2 allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR SO_2 Group 2 allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR SO_2 Group 2 allowances deducted equals the

amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR SO_2 Group 2 allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR SO_2 Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR SO_2 Group 2 allowances that each owner is required to hold in accordance with § 97.706(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 2 allowances that owners are required to hold in accordance with the calculation formula in § 97.706(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 2 allowances that owners are required to hold in accordance with the calculation formula in § 97.706(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR SO_2 Group 2 allowances that an owner is required to hold for the control period in the year involved with regard to the State involved—

(A) Where the amount of TR SO_2 Group 2 allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR SO_2 Group 2 allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR SO_2 Group 2 allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR SO_2 Group 2 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR SO_2 Group 2 allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance account) for the control period in the year involved.

(C) Each TR SO_2 Group 2 allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements under the TR SO_2 Group 2 assurance provisions for a control period in a given year must be a TR SO_2 Group 2 allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR SO_2 Group 2 allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR SO_2 Group 2 allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 2 allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 2 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 2 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 2 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.726 Banking.

(a) A TR SO_2 Group 2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR SO_2 Group 2 allowance that is held in a compliance account or a general account will remain in such

account unless and until the TR SO_2 Group 2 allowance is deducted or transferred under § 97.711(c), § 97.723, § 97.724, § 97.725, 97.727, 97.728, 97.742, or 97.743.

§ 97.727 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.728 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO_2 Group 2 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR SO_2 Group 2 allowances from or transfer TR SO_2 Group 2 allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.729 [Reserved]

§ 97.730 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO_2 Group 2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.702 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR SO_2 Group 2 unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.702, and the term "newly affected unit" shall be deemed to mean "newly affected TR SO_2 Group 2 unit". The owner or operator of a unit that is not a TR SO_2 Group 2 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO_2 Group 2 unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR SO_2 Group 2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 97.731 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO_2 Group 2 unit that commences commercial operation before July 1, 2011, by January 1, 2012.

(2) For the owner or operator of a TR SO_2 Group 2 unit that commences commercial operation on or after July 1, 2011, by the later of the following dates:

(i) January 1, 2012; or

(ii) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a TR SO_2 Group 2 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO_2 emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.741(c).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a TR SO_2 Group 2 opt-in unit, by the date on which the TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program as provided in § 97.741(h).

(c) Reporting data. The owner or operator of a TR SO_2 Group 2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a TR SO_2 Group 2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.735.

(2) No owner or operator of a TR SO_2 Group 2 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR SO_2 Group 2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR SO_2 Group 2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.705 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same

pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.731(d)(3)(i).

(e) Long-term cold storage. The owner or operator of a TR SO_2 Group 2 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.731 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO_2 Group 2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.730(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.730(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO_2 Group 2 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 97.730(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.730(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.730(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.730(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 97.730(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.730(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.733.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO_2 Group 2 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR SO_2 Group 2 Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period specified in paragraph

(d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.732(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.732 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.731 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.731 for each disapproved monitoring system.

§ 97.733 Notifications concerning monitoring.

The designated representative of a TR SO_2 Group 2 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.734 Recordkeeping and reporting.

(a) General provisions. The designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 97.714(a).

(b) Monitoring plans. The owner or operator of a TR SO_2 Group 2 unit shall comply with requirements of § 75.62 of this chapter.

(c) Certification applications. The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.731, including the information required under § 75.63 of this chapter.

(d) Quarterly reports. The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for the TR SO_2 Group 2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.730(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall

commence in the quarter covering January 1, 2012 through March 31, 2012;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.741(c); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a TR SO_2 Group 2 opt-in unit, the calendar quarter corresponding to the date on which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 2 Trading Program as provided in § 97.71(h).

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For TR SO_2 Group 2 units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 97.735 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO_2 Group 2 unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.730 through 97.734 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.702.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.740 General requirements for TR SO_2 Group 2 opt-in units.

(a) A TR SO_2 Group 2 opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR SO_2 Group 2 unit under § 97.704;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR SO_2 Group 2 opt-in unit shall be deemed to be a TR SO_2 Group 2 unit for purposes of applying this subpart, except for §§ 97.705, 97.711, and 97.712.

(c) Solely for purposes of applying the requirements of §§ 97.713 through 97.718 and §§ 97.730 through 97.735, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.742 shall be deemed to be a TR SO_2 Group 2 unit.

(d) Any TR SO_2 Group 2 opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.742, located at the same source as one or more TR SO_2 Group 2 units shall have the same designated representative and alternate designated representative as such TR SO_2 Group 2 units.

§ 97.741 Opt-in process.

A unit meeting the requirements for a TR SO_2 Group 2 opt-in unit in § 97.740(a) may become a TR SO_2 Group 2 opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt-in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.742(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located,

including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR SO_2 Group 2 unit under § 97.704;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.730 through 97.735;

(4) A statement that the unit, if approved to become a TR SO_2 Group 2 unit under paragraph (g) of this section, may withdraw from the TR SO_2 Group 2 Trading Program only in accordance with § 97.742;

(5) A statement that the unit, if approved to become a TR SO_2 Group 2 unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.743;

(6) A complete certificate of representation under § 97.716 consistent with § 97.740, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) *Interim review of monitoring plan.* The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO_2 emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.730 through 97.735. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) *Monitoring and reporting.* (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the SO_2 emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.730 through 97.735, starting on the date of certification of the necessary monitoring systems under §§ 97.730 through 97.735 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR SO_2 Group 2 Trading Program in accordance with § 97.742.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR SO_2 Group 2 Trading Program under paragraph (h) of this section, during which period monitoring system availability must not be less than 98 percent under §§ 97.730 through 97.735 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the SO_2 emission rate and the heat input of the unit are monitored and reported in accordance with §§ 97.730 through 97.735 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.730 through 97.735 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR SO_2 Group 2 Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline SO_2 emission rate.* The unit's baseline SO_2 emission rate shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's SO_2 emission rate (in lb/mmBtu) for such control period;

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods during which the unit has add-on SO_2 emission controls.

(g) *Review of TR opt-in application.*

(1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR SO_2 Group 2 opt-in unit in § 97.640, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approval will state the unit's baseline heat input and baseline SO_2 emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR SO_2 Group 2 opt-in unit in § 97.740, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) *Date of entry into TR SO_2 Group 2 Trading Program.* A unit for which a

TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR SO_2 Group 2 opt-in unit, and a TR SO_2 Group 2 unit, effective as of the later of January 1, 2012 or January 1 of the first control period during which such approval is issued.

§ 97.742 Withdrawal of TR SO_2 Group 2 opt-in unit from TR SO_2 Group 2 Trading Program.

A TR SO_2 Group 2 opt-in unit may withdraw from the TR SO_2 Group 2 Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR SO_2 Group 2 opt-in unit from the TR SO_2 Group 2 Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of the unit's entry into the TR SO_2 Group 2 Trading Program under § 97.741(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR SO_2 Group 2 opt-in unit covered by the request to withdraw may withdraw from the TR SO_2 Group 2 Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR SO_2 Group 2 opt-in unit must meet the requirement to hold TR SO_2 Group 2 allowances under §§ 97.724 and 97.725 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit TR SO_2 Group 2 allowances equal in amount to and allocated for the same or a prior control period as any TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under § 97.744 for any control period after the date on which the withdrawal is to be effective. If there are no other TR SO_2 Group 2 units at the source, the Administrator will close the compliance account, and the owners and operators of the TR SO_2 Group 2 opt-in unit may submit a TR SO_2 Group 2 allowance transfer for any remaining TR SO_2 Group 2 allowances to another Allowance Management System account in accordance with §§ 97.722 and 97.723.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR SO_2 Group 2 allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on December 31 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR SO_2 Group 2 opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR SO_2 Group 2 Trading Program concerning any control periods for which the unit is a TR SO_2 Group 2 opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR SO_2 Group 2 opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR SO_2 Group 2 Trading Program.* Once a TR SO_2 Group 2 opt-in unit withdraws from the TR SO_2 Group 2 Trading Program, the designated representative may not submit another opt-in application under § 97.741 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.743 Change in regulatory status.

(a) *Notification.* If a TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR SO_2 Group 2 opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.604, the Administrator will deduct, from the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit that becomes a TR SO_2 Group 2 unit under § 97.704, TR SO_2 Group 2 allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under § 97.744 for any control period starting after the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704; and

(ii) If the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704 is not December 31, the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under § 97.744 for the control period that includes the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit that becomes a TR SO_2 Group 2 unit under § 97.704 contains the TR SO_2 Group 2 allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, the TR SO_2 Group 2 opt-in unit will be allocated TR SO_2 Group 2 allowances in accordance with § 97.712.

(ii) If the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704 is not December 31, the following amount of TR SO_2 Group 2 allowances will be allocated to the TR SO_2 Group 2 opt-in unit (as a TR SO_2 Group 2 unit) in accordance with § 97.712 for the control period that includes the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704:

(A) The amount of TR SO_2 Group 2 allowances otherwise allocated to the TR SO_2 Group 2 opt-in unit (as a TR SO_2 Group 2 unit) in accordance with § 97.712 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, divided by the total number of days in the control period; and

(C) Rounded to the nearest allowance.

§ 97.744 TR SO_2 Group 2 allowance allocations to TR SO_2 Group 2 opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.741(g), the Administrator will issue TR SO_2 Group 2 allowances and allocate them to the unit for the control period in which the unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h), in accordance with paragraph (b) of this section.

(2) By no later than October 31 of the control period after the control period in which a TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h) and October 31 of each year thereafter, the Administrator will issue TR SO_2 Group 2 allowances and allocate them to the TR SO_2 Group 2 opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR SO_2 Group 2 opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR SO_2 Group 2 opt-in unit is to be allocated TR SO_2 Group 2 allowances, the Administrator will issue and allocate TR SO_2 Group 2 allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR SO_2 Group 2 allowance allocation will be the lesser of:

(i) The TR SO_2 Group 2 opt-in unit's baseline heat input determined under § 97.741(g); or

(ii) The TR SO_2 Group 2 opt-in unit's heat input, as determined in accordance with §§ 97.730 through 97.735, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h).

(2) The SO_2 emission rate (in lb/mmBtu) used for calculating TR SO_2 Group 2 allowance allocations will be the lesser of:

(i) The TR SO_2 Group 2 opt-in unit's baseline SO_2 emission rate (in lb/mmBtu) determined under § 97.741(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO_2 emissions limitation applicable to the TR SO_2 Group 2 opt-in unit at any time during the control period for which TR SO_2 Group 2 allowances are to be allocated.

(3) The Administrator will issue TR SO_2 Group 2 allowances and allocate them to the TR SO_2 Group 2 opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the SO_2 emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit, the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period after the control period in which a TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit, the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under paragraph (a)(2) of this section.

[FR Doc. 2010–17007 Filed 7–30–10; 8:45 am]

BILLING CODE 6560–50–P

Dated: July 26, 2010.

Gary Kassof,

Bridge Program Manager, First Coast Guard District.

[FR Doc. 2010–19290 Filed 8–4–10; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52 and 81

[EPA–R04–OAR–2010–0134–201027; FRL–9184–9]

Approval and Promulgation of Implementation Plans and Designation of Areas for Air Quality Planning Purposes; Kentucky; Redesignation of the Kentucky Portion of the Cincinnati-Hamilton 1997 8-Hour Ozone Nonattainment Area to Attainment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is taking final action to approve a request submitted on January 29, 2010, from the Commonwealth of Kentucky, through the Kentucky Energy and Environment Cabinet, Division for Air Quality (DAQ), to redesignate the Kentucky portion of the tri-state Cincinnati-Hamilton 8-hour ozone nonattainment area (hereafter referred to as "the Cincinnati-Hamilton Area") to attainment for the 1997 8-hour ozone national ambient air quality standards (NAAQS). The Cincinnati-Hamilton Area is comprised of Boone, Campbell and Kenton Counties in Kentucky (hereafter also referred to as "Northern Kentucky"); Butler, Clermont, Clinton, Hamilton and Warren Counties in Ohio; and a portion of Dearborn County in Indiana. EPA's approval of the redesignation request is based on the determination that Northern Kentucky has met the criteria for redesignation to attainment set forth in the Clean Air Act (CAA), including the determination that the Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS. Additionally, EPA is approving a revision to the Kentucky State Implementation Plan (SIP) including the 1997 8-hour ozone maintenance plan for Northern Kentucky that contains the new 2015 and 2020 motor vehicle emission budgets (MVEBs) for nitrogen oxides (NO_X) and volatile organic compounds (VOC) for Northern Kentucky. This action also approves the emissions inventory submitted with the maintenance plan. EPA has previously approved, in a separate rulemaking, similar redesignation requests submitted by the States of Ohio and Indiana for their portions of this 1997 8-hour ozone area.

DATES: *Effective Date:* This rule will be effective August 5, 2010.

ADDRESSES: EPA has established a docket for this action under Docket Identification No. EPA–R04–OAR–2010–0134. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *i.e.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday, 8:30 to 4:30, excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Jane Spann, Regulatory Development Section, Air Planning Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street, SW., Atlanta, Georgia 30303–8960. Jane Spann may be reached by phone at (404) 562–9029 or via electronic mail at *spann.jane@epa.gov*.

SUPPLEMENTARY INFORMATION:

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I. What Is the Background for the Actions?

On January 29, 2010, the Commonwealth of Kentucky, through DAQ, submitted a request to redesignate Northern Kentucky (as a portion of the Cincinnati-Hamilton Area) to attainment for the 1997 8-hour ozone NAAQS, and for EPA approval of the Kentucky SIP revision containing a maintenance plan for Northern Kentucky. In an action published on May 12, 2010 (75 FR 26685), EPA proposed to approve the redesignation of Northern Kentucky to attainment. EPA also proposed approval as a SIP revision of Kentucky's plan for maintaining the 1997 8-hour NAAQS, including the emissions inventory submitted pursuant to CAA section 172(c)(3); and the NO_X and VOC MVEBs for Northern Kentucky contained in the maintenance plan. The background for these rulemakings is set forth in detail in EPA's May 12, 2010 proposal.

The MVEBs included in the maintenance plan are as follows:

TABLE 1—NORTHERN KENTUCKY VOC AND NO_X MVEBS

[Summer season tons per day (tpd)]

Year	2015	2020
NO_X	14.40	13.27
VOC	9.76	10.07

In its May 12, 2010, proposed action, EPA stated that the adequacy public comment period on these MVEBs (as contained in Kentucky's submittal) began on February 3, 2010, and closed on March 5, 2010. No comments were received during this public comment period, and therefore, EPA deems the new MVEBs for Northern Kentucky adequate for the purposes of transportation conformity. In a separate action, EPA previously found adequate and approved the MVEB's for the Ohio and Indiana portions of the Cincinnati-Hamilton Area (75 FR 26118, May 11, 2010).

As we stated in the May 12, 2010, proposal, this redesignation addresses Northern Kentucky's status solely with respect to the 1997 8-hour ozone NAAQS, for which designations were finalized on April 30, 2004 (69 FR 23857). In 2008, EPA issued a revised 8-hour ozone NAAQS, which is currently under reconsideration. Today's rulemaking concerns only the 1997 8-hour ozone NAAQS, and does not address or affect the 2008 or any subsequently revised and promulgated ozone NAAQS.

In this final rulemaking, EPA is noting a correction for the site identification numbers listed in EPA's May 12, 2010 (75 FR 26685), proposed approval. Specifically, the air quality monitor site identification number (ID) listed in Table 2 (Annual 4th Max High and Design Value Concentration for 8-Hour Ozone for the Cincinnati-Hamilton OH-KY-IN Area (parts per million)) of EPA's May 12, 2010 proposed rulemaking, column 3 labeled "Monitor" were incorrect for the Boone and Campbell County, Kentucky entries. The site monitor IDs should read: Boone

County—KY 338 & Lower River Road *21–015–0003* and Campbell County—Highland Heights *21–037–3002*. Please see below for the corrected table.

TABLE 2—ANNUAL 4TH MAX HIGH AND DESIGN VALUE CONCENTRATION FOR 8-HOUR OZONE FOR THE CINCINNATI-HAMILTON OH-KY-IN AREA

[Parts per million]

State*/county	Monitor	2007 4th high (ppm)	2008 4th high (ppm)	2009 4th high (ppm)	2007–2009 average (ppm)
Ohio:					
Butler	Hamilton, 39–017–0004	0.091	0.071	0.073	0.078
	Middletown, 39–017–1004	0.091	0.079	0.076	0.082
Clermont	Batavia 39–025–0022	0.086	0.071	0.069	0.075
Clinton	Wilmington, 39–027–1022	0.082	0.076	0.070	0.076
Hamilton	Grooms Rd., Cincinnati, 39–061–0006	0.089	0.086	0.072	0.082
	Cleves, 39–061–0010	0.086	0.077	0.065	0.076
	250 Wm. Howard Taft, Cincinnati, 39–061–0040	0.086	0.080	0.074	0.080
Warren	Lebanon, 39–165–0007	0.088	0.082	0.077	0.082
Kentucky:					
Boone	KY 338 & Lower River Road, *21–015–0003*	0.078	0.064	0.064	0.068
Campbell	Highland Heights, *21–037–3002*	0.086	0.075	0.068	0.076
Kenton	Covington, 21–117–0007	0.085	0.073	0.074	0.077

II. What Actions Is EPA Taking?

In today's rulemaking, EPA is finalizing several related actions. EPA is approving: (1) Kentucky's redesignation request to change the legal designation of the Northern Kentucky portion of the Cincinnati-Hamilton Area from nonattainment to attainment for the 1997 8-hour ozone NAAQS; (2) Kentucky's 1997 8-hour ozone maintenance plan for Northern Kentucky, including MVEB's (such approval being one of the CAA criteria for redesignation to attainment status); and (3) Kentucky's emissions inventory which was submitted pursuant to CAA section 172(c)(3). The maintenance plan is designed to help keep the Cincinnati-Hamilton Area in attainment for the 1997 8-hour ozone NAAQS through 2020. EPA's approval of the redesignation request is based on EPA's determination that Northern Kentucky meets the criteria for redesignation set forth in CAA, sections 107(d)(3)(E) and 175A, including EPA's determination that the Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS. EPA's analyses of Kentucky's redesignation request, emissions inventory, and maintenance plan are described in detail in the May 12, 2010 proposed rule (75 FR 26685).

Consistent with the CAA, the maintenance plan that EPA is approving also includes 2015 and 2020 MVEBs for NO_X and VOC for Northern Kentucky. In this action, EPA is approving these NO_X and VOC MVEBs for the purposes of transportation conformity. For regional emission analysis years that involve the year 2015, and any year between 2015 and 2020, the new 2015 MVEBs are the applicable budgets (for the purpose of conducting transportation conformity analyses). For regional emission analysis years that involve the year 2020 and beyond, the applicable budgets, for the purpose of conducting transportation conformity analyses, are the new 2020 MVEBs.

III. Why Is EPA Taking These Actions?

EPA has determined that the Cincinnati-Hamilton Area has attained the 1997 8-hour ozone NAAQS and has also determined that all other criteria for the redesignation of Northern Kentucky (as part of the Cincinnati-Hamilton Area) from nonattainment to attainment of the 1997 8-hour ozone NAAQS have been met. See section 107(d)(3)(E) of the CAA. EPA is also taking final action to approve the maintenance plan for Northern Kentucky as meeting the requirements of sections 175A and 107(d)(3)(E) of the CAA, and the emissions inventory as meeting the requirements of section 172(c)(3) of the CAA. Furthermore, EPA is approving the new NO_X and VOC MVEBs for the years 2015 and 2020 as contained in Kentucky's maintenance plan for Northern Kentucky because these MVEBs are consistent with maintenance for the Cincinnati-Hamilton Area. In the May 12, 2010, proposal to redesignate Northern Kentucky, EPA described the applicable criteria for redesignation to attainment and its analysis of how those criteria have been met. The bases and rationale for EPA's findings and actions are set forth in the proposed rulemaking, and in the responses to comments and other discussion in this final rulemaking.

IV. What Are the Effects of These Actions?

Approval of the redesignation request changes the legal designation of Boone, Campbell and Kenton Counties in Kentucky (the Kentucky portion of the Cincinnati-Hamilton Area) from nonattainment to attainment for the 1997 8-hour ozone NAAQS. 40 CFR part 81. EPA is also approving as a revision to the Kentucky SIP, Kentucky's plan for maintaining the 1997 8-hour ozone NAAQS in the Cincinnati-Hamilton Area through 2020. The maintenance plan includes contingency measures to remedy possible future violations of the 1997 8-hour ozone NAAQS, and establishes NO_X and VOC MVEBs for the years 2015 and 2020 for Northern Kentucky. Additionally, this action approves the emissions inventory for Northern Kentucky pursuant to section 172(c)(3) of the CAA.[1]

V. Response to Comments

EPA received one set of comments from the Allegheny County Health Department on EPA's proposal. The comment received addresses minor arithmetic errors in tabulating totals in some maintenance plan emissions inventories. EPA's response to the comment is provided below.

Comment: The Commenter, the Allegheny County Health Department states: "In Table 3 of the proposed approval **Federal Register** the nonroad total for 2018 VOC should be 7.43 tons

[1] On May 11, 2010, EPA took final action to approve Ohio's and Indiana's redesignation requests for their respective portions of the Cincinnati-Hamilton Area, including approval of the associated emissions inventories, maintenance plans and MVEB's (75 FR 26118).

per day (tpd) not 7.68 tpd and the 2018 VOC total for all sources should be 40.10 tpd when the nonroad total is corrected."

Response: EPA acknowledges the Commentor's correction for the total nonroad VOC and also notes that there were additional typographical errors in the proposed rule with regard to some of the totaled emission categories. See Table 3 and 4 below for the corrected VOC and NO_X emissions totals. The corrected numbers are underlined. None of these corrections changes the downward trend of total Northern Kentucky VOC and NO_X emissions from 2008 to 2020, and in some cases the revisions reflect lower emissions totals than were indicated in EPA's proposed rule. With these corrections, as in EPA's original proposal, Kentucky's plan for Northern Kentucky continues to demonstrate maintenance for the initial maintenance period with a total of 3.89 tpd reduction in VOC emissions, and 14.48 tpd reduction in NO_X emissions from the 2008 baseline to the 2020 outyear.

TABLE 3—NORTHERN KENTUCKY VOC EMISSIONS (tpd)

	2008	2011	2015	2018	2020
Point					
Boone	2.81	2.90	3.04	3.14	3.20
Campbell	0.28	0.29	0.30	0.31	0.31
Kenton	1.17	1.23	1.31	1.38	1.42
Point Total	*4.26*	4.42	4.65	*4.83*	4.93
Area					
Boone	8.41	8.45	8.50	8.50	8.50
Campbell	4.34	4.28	4.20	4.20	4.20
Kenton	7.88	7.79	7.66	7.66	7.66
Area Total	20.63	20.52	20.36	20.36	20.36
Nonroad					
Boone	5.07	4.84	4.55	4.44	4.36
Campbell	1.51	1.41	1.29	1.25	1.22
Kenton	1.95	1.87	1.76	1.74	1.73
Nonroad Total	8.53	8.12	7.60	*7.43*	7.31
Mobile*					
Boone	4.00	3.63	3.17	3.04	2.96
Campbell	2.29	2.04	1.74	1.62	1.55
Kenton	3.85	3.39	2.85	2.67	2.56
Mobile Total	10.14	9.06	*7.76*	*7.33*	7.07
Northern Kentucky Total	*43.56*	42.12	*40.37*	*39.95*	39.67

* Calculated using MOBILE6.2.

TABLE 4—NORTHERN KENTUCKY NO_X EMISSIONS (tpd)

	2008	2011	2015	2018	2020
Point					
Boone	23.27	24.04	25.08	25.91	26.47
Campbell	0.02	0.02	0.02	0.03	0.03
Kenton	0.03	0.03	0.03	0.03	0.03
Point Total	23.32	24.09	25.13	25.97	26.53
Area					
Boone	5.02	5.02	5.03	5.03	5.03
Campbell	1.32	1.31	1.30	1.30	1.30
Kenton	4.06	4.04	4.02	4.02	4.02
Area Total	10.40	10.37	10.35	10.35	10.35
Nonroad					
Boone	11.02	10.47	9.77	9.60	9.48
Campbell	5.34	5.00	4.57	4.43	4.34

TABLE 4—NORTHERN KENTUCKY NO_X EMISSIONS (tpd)—Continued

	2008	2011	2015	2018	2020
Kenton	7.33	6.81	6.15	5.91	5.75
Nonroad Total	23.69	22.28	20.49	19.94	19.57
Mobile*					
Boone	8.53	6.64	4.63	3.90	3.45
Campbell	4.88	3.74	2.54	2.09	1.81
Kenton	8.37	6.33	4.23	3.47	3.01
Mobile Total	21.78	16.71	11.40	9.46	8.27
Northern Kentucky Total	79.19	73.45	67.37	65.72	*64.72*

* Calculated using MOBILE6.2.

EPA has determined that the Commonwealth's redesignation request meets all of the CAA redesignation criteria for the 1997 8-hour ozone NAAQS. EPA's May 12, 2010, proposed rulemaking, as supplemented by today's notice, specifically addresses each of the criteria and provides detailed analysis of how they are met.

VI. Final Action

After evaluating Kentucky's redesignation request and comments received, EPA is taking final action to approve the redesignation and change the legal designation of Boone, Campbell and Kenton Counties in Kentucky (as part of the Cincinnati-Hamilton Area) from nonattainment to attainment for the 1997 8-hour ozone NAAQS. EPA has already taken final action to approve the redesignation requests, emission inventories and maintenance plans for the Ohio and Indiana portions of this Area in a separate but coordinated action. See 75 FR 26118. Through this action, EPA is also approving into the Kentucky SIP, the 1997 8-hour ozone maintenance plan for Northern Kentucky, which includes the new NOx MVEBs of 14.40 tpd for 2015, and 13.27 tpd for 2020; and new VOC MVEBs of 9.76 tpd for 2015, and 10.07 tpd for 2020. Additionally, EPA is approving the emissions inventory for Northern Kentucky pursuant to section 172(c)(3) of the CAA. Finally, EPA is finding the new Northern Kentucky MVEBs are adequate for the purposes of transportation conformity. Within 24 months from the effective date of EPA's adequacy finding for the MVEBs, the transportation partners will need to demonstrate conformity to the new NOx and VOC MVEBs pursuant to 40 CFR 93.104(e).

In accordance with 5 U.S.C. 553(d), EPA finds there is good cause for this action to become effective immediately upon publication. This is because a delayed effective date is unnecessary due to the nature of a redesignation to attainment, which relieves the area from certain CAA requirements that would otherwise apply to it. The immediate effective date for this action is authorized under both 5 U.S.C. 553(d)(1), which after publication it provides that rulemaking actions may become effective less than 30 days after publication if the rule "grants or recognizes an exemption or relieves a restriction," and section 553(d)(3), which allows an effective date less than 30 days after publication "as otherwise provided by the agency for good cause found and published with the rule." The purpose of the 30-day waiting period prescribed in section 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. Today's rule, however, does not create any new regulatory requirements such that affected parties would need time to prepare before the rule takes effect. Rather, today's rule relieves the Commonwealth of various requirements for the Northern Kentucky Area. For these reasons, EPA finds good cause under 5 U.S.C. 553(d)(3) for this action to become effective on the date of publication of this action.

VII. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country

located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by October 4, 2010. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (*See* section 307(b)(2)).

List of Subjects

40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Nitrogen dioxide, Ozone, Intergovernmental relations, and Volatile organic compounds.

40 CFR Part 81

Environmental protection and Air pollution control.

Dated: July 26, 2010.

A. Stanley Meiburg,

Acting Regional Administrator, Region 4.

■ Accordingly, 40 CFR parts 52 and 81 are amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart S—Kentucky

■ 2. Section 52.920(e) is amended by adding a new entry at the end of the table for "Northern Kentucky 8-Hour Ozone Maintenance Plan" to read as follows:

§ 52.920 Identification of plan.

* * * * *

(e) * * *

EPA–APPROVED KENTUCKY NON-REGULATORY PROVISIONS

Name of non-regulatory SIP provision	Applicable geographic or nonattainment area	State submittal date/effective date	EPA approval date	Explanations
*	*	*	*	*
Northern Kentucky 8-Hour Ozone Maintenance plan.	Boone, Campbell and Kenton Counties in Kentucky.	1/29/2010	8/5/2010 [Insert citation of publication].	For the 1997 8-hour ozone NAAQS.

PART 81—[AMENDED]

■ 3. The authority citation for part 81 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 4. In § 81.318, the table entitled "Kentucky-Ozone (8-Hour Standard)" is amended under "Cincinnati-Hamilton, OH-KY-IN" by revising the entries for "Boone County," "Campbell County," and "Kenton County" to read as follows:

§ 81.318 Kentucky.

* * * * *

KENTUCKY-OZONE

[8-Hour Standard]

Designated	Designation [a]		Category/classification	
	Date [1]	Type	Date [1]	Type
Cincinnati-Hamilton, OH-KY-IN:				
Boone County	This action is effective 08/05/10	Attainment		
Campbell County	This action is effective 08/05/10	Attainment		
Kenton County	This action is effective 08/05/10	Attainment		
*	*	*	*	*

[a] Includes Indian Country located in each county or area, except as otherwise specified.
[1] This date is June 15, 2004, unless otherwise noted.

* * * * *

[FR Doc. 2010–19170 Filed 8–4–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 271 and 272

[EPA–R06–2009–0570; FRL–9172–6]

Louisiana: Final Authorization of State-Initiated Changes and Incorporation by Reference of Approved State Hazardous Waste Management Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: During a review of Louisiana's regulations, the EPA identified a variety of State-initiated changes to its hazardous waste program under the Resource Conservation and Recovery Act (RCRA). We have determined that these changes are minor and satisfy all requirements needed to qualify for Final authorization and are authorizing the State-initiated changes through this direct Final action. In addition, this document corrects technical errors made in various **Federal Register** authorization documents for Louisiana.

The Solid Waste Disposal Act, as amended, commonly referred to as the Resource Conservation and Recovery Act (RCRA), allows the Environmental Protection Agency (EPA) to authorize States to operate their hazardous waste management programs in lieu of the Federal program. The EPA uses the regulations entitled "Approved State Hazardous Waste Management Programs" to provide notice of the authorization status of State programs and to incorporate by reference those provisions of the State statutes and regulations that will be subject to the EPA's inspection and enforcement. The rule codifies in the regulations the prior approval of Louisiana's hazardous waste management program and incorporates by reference authorized provisions of the State's statutes and regulations.

DATES: This regulation is effective October 4, 2010, unless the EPA receives adverse written comment on this regulation by the close of business September 7, 2010. If the EPA receives such comments, it will publish a timely withdrawal of this direct final rule in the **Federal Register** informing the public that this rule will not take effect. The Director of the Federal Register approves this incorporation by reference as of October 4, 2010 in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

ADDRESSES: Submit your comments by one of the following methods:

1. *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the on-line instructions for submitting comments.

2. *E-mail: patterson.alima@epa.gov* or *banks.julia@epa.gov.*

3. *Mail:* Alima Patterson, Region 6, Regional Authorization Coordinator, or Julia Banks, Codification Coordinator, State/Tribal Oversight Section (6PD–O), Multimedia Planning and Permitting Division, EPA Region 6, 1445 Ross Avenue, Dallas, Texas 75202–2733.

4. *Hand Delivery or Courier:* Deliver your comments to Alima Patterson, Region 6, Regional Authorization Coordinator, or Julia Banks, Codification Coordinator, State/Tribal Oversight Section (6PD–O), Multimedia Planning and Permitting Division, EPA Region 6, 1445 Ross Avenue, Dallas, Texas 75202–2733.

Instructions: Direct your comments to Docket ID No. EPA–R06–RCRA–2009–0570. EPA's policy is that all comments received will be included in the public docket without change, including personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov,* or e-mail. The Federal *http://www.regulations.gov* Web site is an "anonymous access" system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to the EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties, and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. (For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www.spa.gov/epahome/dockets.htm).*

You can view and copy the documents that form the basis for this codification and associated publicly available materials from 8:30 a.m. to 4 p.m. Monday through Friday at the following location: EPA Region 6, 1445 Ross Avenue, Dallas, Texas, 75202–2733, phone number (214) 665–8533 or (214) 665–8178. Interested persons wanting to examine these documents should make an appointment with the office at least two weeks in advance.

FOR FURTHER INFORMATION CONTACT: Alima Patterson, Region 6 Regional Authorization Coordinator, or Julia Banks, Codification Coordinator, State/Tribal Oversight Section (6PD–O), Multimedia Planning and Permitting Division, (214) 665–8533 or (214) 665–8178, EPA Region 6, 1445 Ross Avenue, Dallas, Texas 75202–2733, and e-mail address *patterson.alima@epa.gov* or *banks.julia@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Authorization of State-Initiated Changes

A. Why are revisions to State programs necessary?

States which have received Final authorization from the EPA under RCRA section 3006(b), 42 U.S.C. 6926(b), must maintain a hazardous waste program that is equivalent to, consistent with, and no less stringent than the Federal hazardous waste program. As the Federal program changes, the States must change their programs and ask the EPA to authorize the changes. Changes to State hazardous waste programs may be necessary when Federal or State statutory or regulatory authority is modified or when certain other changes occur. Most commonly, States must change their programs because of changes to the EPA's regulations in 40 Code of Federal Regulations (CFR) parts 124, 260 through 268, 270, 273 and 279. States can also initiate their own changes to their hazardous waste program and these changes must then be authorized.

B. What decisions have we made in this rule?

We conclude that Louisiana's revisions to its authorized program meet all of the statutory and regulatory requirements established by RCRA. We found that the State-initiated changes make Louisiana's rules more clear or conform more closely to the Federal equivalents and are so minor in nature that a formal application is unnecessary. Therefore, we grant Louisiana final authorization to operate its hazardous

Appendix C

Ambient Data, Meteorology, and Monitor Site Descriptions

From: Apache [apache@wwwagwx.ca.uky.edu]
Sent: Tuesday, March 09, 2010 1:46 PM
To: Weaver, Susan (EEC)
Subject: Weather Data Request

This data provided by the University of Kentucky Agricultural Weather Center (Phone (859)257-3000 ext.245) World Wide Web URL: http://wwwagwx.ca.uky.edu/

Covington Monthly Climate Data(01-2007 to 12-2009)

		AIR TEMPERATURE						NO. OF DAYS		-- SOD 4" TEMP
		AVERAGE			EXTREME		AVG DEPART	MAX	MIN	AVERAGE
YEAR	MONTH	MAX	MIN	AVG	MAX	MIN	FROM NORM	>=90	<=32	MAX MIN
2007	Jan	42	29	35	65	12	+3	0	20	43 40
2007	Feb	32	16	24	53	-2	-12	0	24	33 32
2007	Mar	60	41	51	82	17	+6	0	13	48 45
2007	Apr	61	43	52	85	23	-4	0	6	54 51
2007	May	80	56	68	89	39	+4	0	0	68 63
2007	Jun	86	63	75	94	51	+3	10	0	75 70
2007	Jul	86	64	75	91	53	-1	5	0	77 73
2007	Aug	94	70	82	101	60	+7	26	0	78 75
2007	Sep	86	61	73	97	47	+4	12	0	73 69
2007	Oct	71	52	62	91	30	+5	2	2	65 61
2007	Nov	52	36	44	69	18	-2	0	11	51 48
2007	Dec	42	30	36	67	14	-1	0	20	45 42
2008	Jan	37	23	30	67	2	-2	0	24	40 36
2008	Feb	38	26	32	63	4	-4	0	23	41 37
2008	Mar	49	33	41	71	6	-4	0	17	45 41
2008	Apr	64	45	55	81	31	-1	0	1	56 52
2008	May	71	51	61	85	37	-3	0	0	59 59
2008	Jun	84	62	73	90	51	+1	5	0	75 70
2008	Jul	85	64	75	92	47	-1	6	0	78 73
2008	Aug	85	64	75	93	54	-0	8	0	79

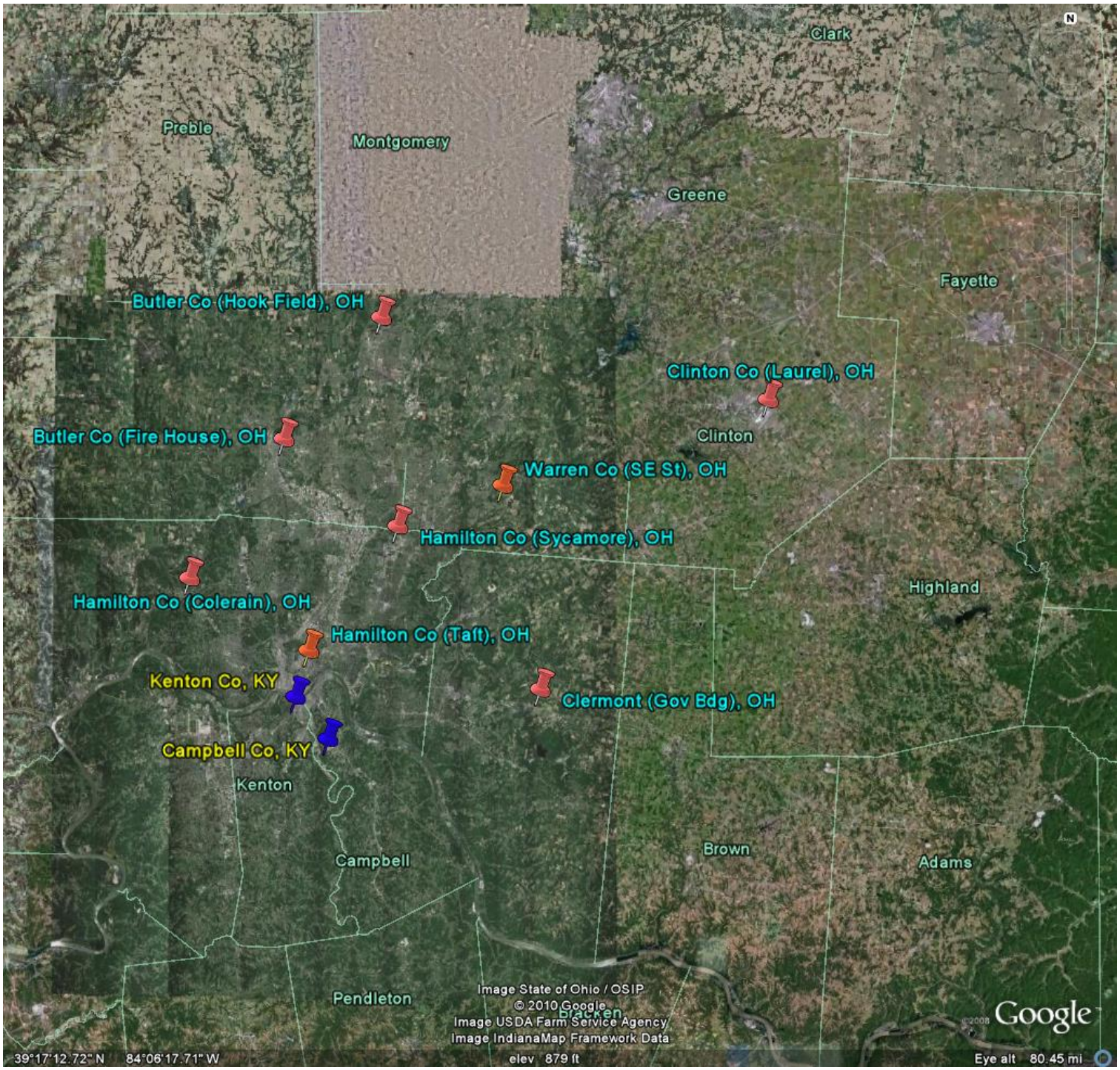
73										
2008	Sep	82	60	71	95	50	+2	6	0	75
70										
2008	Oct	67	45	56	84	25	-1	0	2	63
58										
2008	Nov	51	34	43	74	12	-3	0	15	48
45										
2008	Dec	40	26	33	70	3	-4	0	24	41
38										
2009	Jan	33	20	26	59	-6	-6	0	28	36
34										
2009	Feb	44	28	36	63	-5	-0	0	18	38
36										
2009	Mar	57	38	47	77	9	+2	0	9	48
45										
2009	Apr	64	45	55	85	30	-1	0	4	56
52										
2009	May	74	56	65	85	41	+1	0	0	65
63										
2009	Jun	82	63	73	91	48	+1	3	0	77
72										
2009	Jul	79	62	70	85	53	-6	0	0	75
71										
2009	Aug	82	63	72	91	50	-3	1	0	75
72										
2009	Sep	77	60	68	85	49	-1	0	0	71
69										
2009	Oct	61	44	53	80	28	-4	0	2	59
56										
2009	Nov	56	40	48	71	27	+2	0	3	51
49										
2009	Dec	39	27	33	59	15	-4	0	23	40
38										

---------- PRECIPITATION ----------

YEAR	MONTH	TOTAL	DEPARTURE FROM NORMAL	CUMULATIVE TOTAL	CUMULATIVE DEPARTURE	GREATEST 24 HOUR TOTAL	% RAIN DAYS	NO. DAYS >=.01
2007	Jan	3.84	+1.25	3.84	+1.25	1.01	32	10
2007	Feb	3.38	+0.69	7.22	+1.94	1.05	32	9
2007	Mar	3.14	-1.10	10.36	+0.84	0.88	39	12
2007	Apr	3.17	-0.58	13.53	+0.26	0.62	37	11
2007	May	0.91	-3.37	14.44	-3.11	0.58	16	5
2007	Jun	1.86	-1.98	16.30	-5.09	0.71	23	7
2007	Jul	1.92	-2.32	18.22	-7.41	0.61	32	10
2007	Aug	0.53	-2.82	18.75	-10.23	0.23	19	6
2007	Sep	2.47	-0.41	21.22	-10.64	1.80	13	4
2007	Oct	7.07	+4.21	28.29	-6.43	2.59	19	6

2007	Nov	2.73	-0.73	31.02	-7.16	1.50	27	8
2007	Dec	5.63	+2.48	36.65	-4.68	1.20	48	15
2008	Jan	2.11	-0.48	38.76	-5.16	0.74	32	10
2008	Feb	5.15	+2.46	43.91	-2.70	1.20	54	15
2008	Mar	9.52	+5.28	53.43	+2.58	2.39	39	12
2008	Apr	2.75	-1.00	56.18	+1.58	1.66	30	9
2008	May	6.32	+2.04	62.50	+3.62	0.99	42	13
2008	Jun	5.21	+1.37	67.71	+4.99	1.93	33	10
2008	Jul	3.16	-1.08	70.87	+3.91	0.93	26	8
2008	Aug	1.78	-1.57	72.65	+2.34	0.93	13	4
2008	Sep	1.22	-1.66	73.87	+0.68	0.79	13	4
2008	Oct	1.63	-1.23	75.50	-0.55	0.84	10	3
2008	Nov	1.71	-1.75	77.21	-2.30	0.69	23	7
2008	Dec	4.51	+1.36	81.72	-0.94	1.82	55	17
2009	Jan	2.87	+0.28	84.59	-0.66	1.01	35	11
2009	Feb	2.37	-0.32	86.96	-0.98	1.04	25	7
2009	Mar	1.58	-2.66	88.54	-3.64	0.40	19	6
2009	Apr	3.70	-0.05	92.24	-3.69	0.61	43	13
2009	May	3.79	-0.49	96.03	-4.18	0.70	45	14
2009	Jun	7.69	+3.85	103.72	-0.33	2.45	43	13
2009	Jul	5.81	+1.57	109.53	+1.24	1.12	48	15
2009	Aug	1.78	-1.57	111.31	-0.33	1.15	10	3
2009	Sep	4.92	+2.04	116.23	+1.71	0.88	40	12
2009	Oct	5.42	+2.56	121.65	+4.27	1.40	39	12
2009	Nov	0.91	-2.55	122.56	+1.72	0.36	13	4
2009	Dec	2.76	-0.39	125.32	+1.33	0.68	39	12

Appendix C: Locations of ambient monitors in the Cincinnati-Hamilton, OH-IN-KY area



Source Map: Google Earth

Latitudes-Longitudes provided by USEPA/AQS AMP380 Site Description Report.

Blue pins are the Kentucky monitors.

Red pins are the Ohio monitors.

Dearborn County, Indiana does not have a monitoring location.

County	State	Site Name	Monitor ID	Latitude	Longitude
Campbell	KY	NKU	21-037-3002	39.021806	-84.474453
Kenton	KY	University College	21-117-0007	39.072500	-84.525000
Butler	OH	Fire House	39-017-0004	39.383333	-84.544167
Butler	OH	Hook Field	39-017-1004	39.530000	-84.392500
Clermont	OH	Gov Bldg	39-025-0022	39.082319	-84.144193
Clinton	OH	Laurel Ctr	39-027-1002	39.430000	-83.788611
Hamilton	OH	Sycamore	39-061-0006	39.278499	-84.365974
Hamilton	OH	Colerain	39-061-0010	39.214931	-84.690723
Hamilton	OH	Taft	39-061-0040	39.128611	-84.504167
Warren	OH	SE St	39-165-0007	39.427797	-84.202208
Source: USEPA/AQS AMP 380 Site Description Report 2010					

UNITES STATES ENVIRONMENTAL PROTECTION AGENCY

User ID: NOQ

QUICKLOOK CRITERIA PARAMETERS

Report Request ID: 720853

Report Code: AMP450

Feb. 19, 2010

GEOGRAPHIC SELECTIONS

Tribal State	County	Site	Parameter	POC	City	AQCR	UAR	CBSA	CSA	EPA Region	Method	Duration	Begin Date	End Date
21				1										

PROTOCOL SELECTIONS

Parameter Classification	Parameter	Method	Duration
CRITERIA	88101		

SELECTED OPTIONS

Option Type	Option Value
EVENTS PROCESSING	EXCLUDE REGIONALLY CONCURRED EVENTS
MERGE PDF FILES	YES

SORT ORDER

Order	Column
1	PARAMETER_CODE
2	STATE_CODE
3	COUNTY_CODE
4	SITE_ID
5	POC
6	DATES
7	EDT_ID

GLOBAL DATES

Start Date	End Date
2000	2009

Feb. 19, 2010

EXCEPTIONAL DATA TYPES

EDT	DESCRIPTION
0	NO EVENTS
1	EVENTS EXCLUDED
2	EVENTS INCLUDED
3	EXCEPTIONAL EVENTS EXCLUDED
4	NATURAL EVENTS EXCLUDED
5	EVENTS WITH CONCURRENCE EXCLUDED
6	EXCEPTIONAL EVENTS WITH CONCURRENCE EXCLUDED
7	NATURAL EVENTS WITH CONCURRENCE EXCLUDED

Note: The * indicates that the mean does
not satisfy summary criteria.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2000	118	53	44.3	41.5	40.2	39.8	41.5	18.23*		0
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2001	118	54	36.8	30.2	28.2	26.6	30.2	15.08	Y	5
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2002	118	57	34.5	25.9	24.5	24.1	25.9	14.29	Y	0
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2003	118	58	42.2	32.7	22.3	21.4	32.7	14.21	Y	0
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2004	118	58	32.0	29.5	25.9	23.0	29.5	13.40	Y	0
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2005	118	55	34.4	31.0	27.2	26.6	31.0	14.95*		5
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2006	118	61	30.2	25.7	24.5	24.1	25.7	13.75		5
21-013-0002	1	0584	Middlesborough (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2007	118	59	40.7	29.5	28.2	27.5	29.5	15.24		5
21-013-0002	1	0584	Middlesborough	Bell	MIDDLESBORO	2008	118	59	30.3	24.4	23.1	23.1	24.4	12.53	Y	0

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PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
			h (corporate name for Middlesboro)		AIRPORT, 34TH & DORCHESTER											
21-013-0002	1	0584	Middlesboroug h (corporate name for Middlesboro)	Bell	MIDDLESBORO AIRPORT, 34TH & DORCHESTER	2009	118	59	29.5	23.1	19.8	18.7	23.1	10.40		0
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2000	118	112	37.2	34.1	34.0	32.6	34.0	15.66		5
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2001	118	115	54.4	38.5	37.7	37.0	37.7	15.27	Y	5
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2002	118	116	46.8	44.2	39.4	39.2	39.4	15.54	Y	0
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2003	118	110	37.7	37.4	33.8	30.7	33.8	13.93	Y	0
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2004	118	120	30.7	30.4	30.3	26.7	30.3	13.29	Y	0
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2005	118	119	39.0	38.1	36.1	35.5	36.1	16.01		5
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2006	118	115	48.6	28.9	28.6	28.0	28.6	13.76		0
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2007	118	117	40.4	39.0	38.5	35.2	38.5	14.34		5
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH	2008	118	121	27.8	25.8	24.3	23.8	24.3	12.06	Y	0

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PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					DEPT											
21-019-0017	1	0584	Ashland	Boyd	2924 HOLT ST, FIVCO HEALTH DEPT	2009	118	118	26.8	24.6	23.5	21.7	23.5	10.94		0
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2000	118	106	39.2	35.8	35.2	35.0	35.2	16.43		5
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2001	118	114	41.6	38.3	32.8	31.5	32.8	15.55	Y	5
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2002	118	116	53.2	45.0	34.1	32.8	34.1	14.69	Y	0
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2003	118	115	40.7	38.9	34.8	31.2	34.8	14.37	Y	0
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2004	118	116	33.8	31.9	28.9	28.8	28.9	13.62	Y	0
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2005	118	114	42.4	41.2	39.0	35.1	39.0	16.32*		5
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2006	118	117	39.0	34.3	33.5	30.9	33.5	14.14		5
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2007	118	118	46.8	37.7	35.1	34.0	35.1	15.14		5
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2008	118	121	29.3	25.9	25.4	24.8	25.4	12.84	Y	0
21-029-0006	1	0584	Shepherdsville	Bullitt	2ND & CARPENTER STS	2009	145	115	25.7	23.5	23.1	22.7	23.1	11.88		0
21-037-0003	1	0584	Fort Thomas	Campbell	700 ALEXANDRIA PK, WATER PLT, FT THOMAS	2000	118	118	34.4	34.0	33.0	31.1	33.0	15.09		5
21-037-0003	1	0584	Fort Thomas	Campbell	700 ALEXANDRIA PK, WATER	2001	118	99	35.8	35.3	31.3	30.5	31.3	13.44	Y	5

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PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					PLT, FT THOMAS											
21-037-0003	1	0584	Fort Thomas	Campbell	700 ALEXANDRIA PK, WATER PLT, FT THOMAS	2002	118	99	42.5	42.3	38.9	37.7	42.3	14.81*	Y	0
21-037-0003	1	0584	Fort Thomas	Campbell	700 ALEXANDRIA PK, WATER PLT, FT THOMAS	2003	118	112	32.6	29.7	28.1	27.8	28.1	13.42	Y	0
21-037-0003	1	0584	Fort Thomas	Campbell	700 ALEXANDRIA PK, WATER PLT, FT THOMAS	2004	118	119	37.2	30.7	27.5	26.9	27.5	12.77	Y	0
21-037-0003	1	0584	Fort Thomas	Campbell	700 ALEXANDRIA PK, WATER PLT, FT THOMAS	2005	118	117	48.5	39.0	38.0	36.0	38.0	14.84		5
21-037-0003	1	0584	Fort Thomas	Campbell	700 ALEXANDRIA PK, WATER PLT, FT THOMAS	2006	118	18	25.2	19.8	17.0	16.8	25.2	11.54*		0
21-037-3002	1	0584	Highland Heights	Campbell	524A John Hill Road	2007	118	50	34.0	33.5	26.3	26.0	34.0	14.36*		5
21-037-3002	1	0584	Highland Heights	Campbell	524A John Hill Road	2008	118	119	30.5	27.3	26.1	24.4	26.1	11.83	Y	0
21-037-3002	1	0584	Highland Heights	Campbell	524A John Hill Road	2009	145	112	24.5	22.7	22.5	21.4	22.5	11.43		0

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Feb. 19, 2010

PM2.5 - Local Conditions (88101) | Kentucky | Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2000	118	107	29.5	28.9	28.8	27.8	28.8	13.75*		5
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2001	118	116	47.3	30.5	28.9	28.8	28.9	12.36	Y	5
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2002	118	115	39.3	37.0	29.8	27.9	29.8	12.44	Y	0
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2003	118	111	31.3	29.7	26.7	26.3	26.7	11.41	Y	0
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2004	118	122	28.6	24.6	24.5	24.1	24.5	11.08	Y	0
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2005	118	117	39.8	39.6	37.2	36.4	37.2	13.55		5
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2006	118	112	43.2	26.3	25.5	24.9	25.5	11.49*		0
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2007	118	116	36.7	31.8	30.9	30.8	30.9	12.81		5
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2008	118	121	25.2	24.5	22.6	21.2	22.6	10.25	Y	0
21-043-0500	1	0584	Not in a city	Carter	CAMP WEBB GRAYSON LAKE	2009	145	120	22.2	19.5	16.9	15.5	16.9	8.77		0
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2000	118	104	40.4	39.7	38.3	34.7	38.3	15.45*		5
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2001	118	111	33.4	27.6	27.2	26.5	27.2	13.51	Y	0
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2002	118	107	35.0	32.0	29.3	25.8	29.3	13.09*	Y	0

Note: The * indicates that the mean does not satisfy summary criteria.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2003	118	103	39.0	38.3	36.8	34.5	36.8	13.86*	Y	0
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2004	118	106	32.7	28.5	26.2	25.1	26.2	11.83*	Y	0
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2005	118	119	44.9	41.0	35.0	34.2	35.0	14.04		5
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2006	118	115	36.8	30.9	30.3	27.1	30.3	12.63		0
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2007	118	116	43.6	39.5	35.5	35.5	35.5	13.99		5
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2008	118	117	28.4	27.9	27.2	26.7	27.2	11.90	Y	0
21-047-0006	1	0584	Not in a city	Christian	10800 PILOT ROCK ROAD, WILLIAMSON RES.	2009	145	103	28.6	28.5	24.0	21.3	24.0	10.71*		0
21-059-0005	1	0584	Owensboro	Daviess	WYNDALL SHPG CTR US 60 & PLSNT VALLEY RD	2005	118	110	38.9	38.6	36.7	36.6	36.7	15.09		5
21-059-0005	1	0584	Owensboro	Daviess	WYNDALL SHPG	2006	118	114	42.7	38.2	30.0	28.8	30.0	13.05		0

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not satisfy summary criteria.

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					CTR US 60 & PLSNT VALLEY RD											
21-059-0005	1	0584	Owensboro	Daviess	WYNDALL SHPG CTR US 60 & PLSNT VALLEY RD	2007	118	110	40.8	38.5	34.9	34.3	34.9	14.17		5
21-059-0005	1	0584	Owensboro	Daviess	WYNDALL SHPG CTR US 60 & PLSNT VALLEY RD	2008	118	115	28.9	24.6	24.4	23.4	24.4	11.99	Y	0
21-059-0005	1	0584	Owensboro	Daviess	WYNDALL SHPG CTR US 60 & PLSNT VALLEY RD	2009	145	114	34.0	28.3	25.4	24.2	25.4	11.89		0
21-059-0014	1	0584	Owensboro	Daviess	KY WESLEYAN COLLEGE, 3000 FREDERICA ST	2000	118	79	40.7	39.5	39.5	37.2	39.5	17.17*		5
21-059-0014	1	0584	Owensboro	Daviess	KY WESLEYAN COLLEGE, 3000 FREDERICA ST	2001	118	113	44.2	41.2	31.5	30.4	31.5	15.18	Y	0
21-059-0014	1	0584	Owensboro	Daviess	KY WESLEYAN COLLEGE, 3000 FREDERICA ST	2002	118	111	49.3	34.6	29.5	28.7	29.5	14.64	N	5
21-059-0014	1	0584	Owensboro	Daviess	KY WESLEYAN COLLEGE, 3000 FREDERICA ST	2003	118	98	45.5	36.5	34.8	34.4	36.5	14.62*	Y	0
21-059-0014	1	0584	Owensboro	Daviess	KY WESLEYAN COLLEGE, 3000 FREDERICA ST	2004	118	116	32.6	27.4	27.0	25.6	27.0	12.47	Y	0
21-061-0501	1	0584	Not in a city	Edmonson	MAMMOTH CAVE NP - ALFRED COOK ROAD	2004	118	117	33.2	26.8	24.2	23.9	24.2	11.58	Y	0

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24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-061-0501	1	0584	Not in a city	Edmonson	MAMMOTH CAVE NP - ALFRED COOK ROAD	2005	118	119	34.4	33.8	33.6	32.8	33.6	13.63		5
21-061-0501	1	0584	Not in a city	Edmonson	MAMMOTH CAVE NP - ALFRED COOK ROAD	2006	118	15	17.1	13.5	12.5	10.0	17.1	8.75*		0
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2000	118	112	38.6	38.5	36.8	31.9	36.8	16.22		5
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2001	118	119	48.6	39.1	35.8	34.3	35.8	15.71	Y	5
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2002	118	115	56.0	53.3	41.6	33.2	41.6	15.08	Y	0
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2003	118	109	28.9	28.6	28.3	28.0	28.3	13.79	Y	0
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2004	118	114	33.0	30.3	29.1	28.6	29.1	13.45	Y	0
21-067-0012	1	0584	Lexington-Fayette	Fayette	650 NEWTOWN PIKE, FAYETTE	2005	118	119	44.1	40.8	35.6	34.7	35.6	15.51		5

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24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
			(corporate name for Lexington)		CO HEALTH DEPT											
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2006	118	119	36.6	34.1	30.4	29.0	30.4	13.67		5
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2007	118	117	51.7	35.1	33.7	29.5	33.7	14.39		5
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2008	118	119	26.0	23.6	23.5	23.0	23.5	12.09	Y	5
21-067-0012	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	650 NEWTOWN PIKE, FAYETTE CO HEALTH DEPT	2009	145	117	23.7	22.0	21.4	21.3	21.4	11.17		0
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2000	118	107	39.5	38.4	38.1	33.0	38.1	16.96*		5
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2001	118	112	49.0	38.1	32.6	31.5	32.6	16.20	Y	5

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24-HOUR

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21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2002	118	115	51.9	49.9	41.0	34.1	41.0	15.56	Y	0
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2003	118	104	43.6	30.0	29.1	28.6	29.1	15.03*	Y	0
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2004	118	121	32.5	30.7	29.2	29.0	29.2	14.32	Y	0
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2005	118	116	41.0	38.2	35.4	35.1	35.4	16.05		5
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2006	118	114	42.8	36.4	32.2	30.6	32.2	13.86		5
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2007	118	108	33.6	33.1	32.0	30.2	32.0	14.12		5
21-067-0014	1	0584	Lexington-Fayette (corporate	Fayette	533 S LIMESTONE	2008	118	116	28.8	24.6	22.7	22.4	22.7	12.10	Y	5

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PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
			name for Lexington)													
21-067-0014	1	0584	Lexington-Fayette (corporate name for Lexington)	Fayette	533 S LIMESTONE	2009	118	112	21.2	20.2	20.0	19.7	20.0	11.15		0
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2000	118	114	37.0	36.3	34.2	31.0	34.2	15.13		5
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2001	118	105	53.1	50.6	35.6	30.1	35.6	13.85	Y	5
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2002	118	111	47.2	46.2	35.0	32.9	35.0	13.85	Y	0
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2003	118	116	36.4	31.2	30.3	28.5	30.3	13.07	Y	0
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2004	118	115	28.9	27.6	26.9	26.1	26.9	12.54	Y	0
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2005	118	118	49.1	45.7	38.0	35.5	38.0	14.59		5
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2006	118	118	37.1	30.2	28.1	26.9	28.1	12.43		0
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2007	118	120	43.9	37.0	35.3	30.0	35.3	13.54		5
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2008	118	119	27.8	24.5	23.2	22.7	23.2	11.45	Y	0
21-073-0006	1	0584	Frankfort	Franklin	803 SCHENKEL LANE	2009	145	120	22.7	22.0	19.6	18.5	19.6	10.47		0
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2000	118	86	39.4	35.0	32.9	32.6	35.0	15.61*		5
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN	2001	118	115	37.7	36.3	30.7	29.6	30.7	14.61	Y	5

Note: The * indicates that the mean does not satisfy summary criteria.

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					LEGION PARK											
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2002	118	115	48.8	37.1	32.2	32.1	32.2	13.98	Y	0
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2003	118	104	39.9	34.5	32.4	26.7	32.4	13.39	Y	0
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2004	118	117	30.6	29.7	27.8	25.3	27.8	12.24	Y	0
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2005	118	118	39.6	39.5	35.1	33.2	35.1	14.50		5
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2006	118	119	37.1	33.3	31.8	29.0	31.8	13.23		0
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2007	118	118	48.7	38.6	38.4	34.9	38.4	14.36		5
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2008	118	110	25.9	25.4	25.2	24.6	25.2	12.22	Y	0
21-093-0006	1	0584	Elizabethtown	Hardin	801 N MILES ST, AMERICAN LEGION PARK	2009	145	116	25.3	23.2	22.3	20.6	22.3	10.97		0
21-101-0006	1	0584	Henderson	Henderson	BEND GATE SCH BEND GATE RD.	2000	118	100	38.5	38.3	34.4	25.6	34.4	14.99		5
21-101-0006	1	0584	Henderson	Henderson	BEND GATE SCH BEND GATE RD.	2001	118	107	38.0	36.6	30.0	28.8	30.0	14.21	Y	0
21-101-0006	1	0584	Henderson	Henderson	BEND GATE SCH BEND GATE RD.	2002	118	119	49.9	45.8	41.4	35.8	41.4	14.18	Y	0
21-101-0006	1	0584	Henderson	Henderson	BEND GATE SCH	2003	118	29	29.0	25.7	25.4	21.5	29.0	13.18*	Y	0

Note: The * indicates that the mean does not satisfy summary criteria.

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					BEND GATE RD.											
21-101-0014	1	0584	Not in a city	Henderson	BASKETT FIRE DEPARTMENT	2003	118	78	47.5	35.8	32.5	31.4	35.8	14.02*	Y	0
21-101-0014	1	0584	Not in a city	Henderson	BASKETT FIRE DEPARTMENT	2004	118	116	27.5	26.1	25.8	25.0	25.8	12.14	Y	0
21-101-0014	1	0584	Not in a city	Henderson	BASKETT FIRE DEPARTMENT	2005	118	110	44.7	36.9	36.7	34.0	36.7	15.36		5
21-101-0014	1	0584	Not in a city	Henderson	BASKETT FIRE DEPARTMENT	2006	118	117	39.1	36.8	28.9	28.4	28.9	13.35		0
21-101-0014	1	0584	Not in a city	Henderson	BASKETT FIRE DEPARTMENT	2007	118	117	35.5	34.6	31.4	30.6	31.4	14.15		5
21-101-0014	1	0584	Not in a city	Henderson	BASKETT FIRE DEPARTMENT	2008	118	113	25.5	25.0	24.3	23.8	24.3	11.92	Y	0
21-101-0014	1	0584	Not in a city	Henderson	BASKETT FIRE DEPARTMENT	2009	145	117	32.2	29.6	26.2	25.6	26.2	11.67		0
21-111-0043	1	0549	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2000	118	342	54.7	50.6	44.5	43.7	39.4	17.31		0
21-111-0043	1	0549	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2001	118	83	48.7	35.7	35.4	34.0	35.7	17.10*		0
21-111-0043	1	0549	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2002	118	319	80.2	54.5	50.0	49.8	46.5	17.16		0
21-111-0043	1	0549	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2003	118	335	44.0	43.2	42.6	40.9	36.3	15.96	Y	0
21-111-0043	1	0549	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2004	118	342	43.7	42.8	35.1	33.1	31.1	14.53		5
21-111-0043	1	0549	Louisville	Jefferson	37TH & SOUTHERN	2005	118	338	48.8	47.8	45.9	44.3	42.9	16.64		5

Note: The * indicates that the mean does not satisfy summary criteria.

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					AVENUE											
21-111-0043	1	0549	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2006	118	298	48.2	39.3	38.0	37.4	36.0	14.96*	Y	5
21-111-0043	1	0584	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2007	118	354	47.7	43.8	43.0	41.4	34.1	15.09	Y	5
21-111-0043	1	0584	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2008	118	333	35.6	32.5	31.9	31.6	28.7	13.17	Y	0
21-111-0043	1	0584	Louisville	Jefferson	37TH & SOUTHERN AVENUE	2009	118	352	31.5	31.2	27.6	26.5	24.3	12.21		0
21-111-0044	1	0549	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2000	118	333	53.1	44.7	43.4	43.2	37.8	16.68		0
21-111-0044	1	0549	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2001	118	347	53.2	46.5	46.1	44.9	43.0	17.73		0
21-111-0044	1	0549	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2002	118	330	100.6	69.4	58.8	57.4	45.4	17.45		0
21-111-0044	1	0549	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2003	118	316	53.5	44.8	42.3	41.5	37.9	15.38	Y	0
21-111-0044	1	0549	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE	2004	118	347	43.5	41.0	34.2	32.7	30.6	14.05		5

Note: The * indicates that the mean does
not satisfy summary criteria.

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					PARK											
21-111-0044	1	0549	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2005	118	331	48.9	44.5	43.2	43.1	40.1	16.40		5
21-111-0044	1	0549	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2006	118	339	48.9	38.4	38.3	38.2	36.3	15.18	Y	5
21-111-0044	1	0584	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2007	118	354	44.5	42.8	41.6	41.2	33.5	14.85	Y	5
21-111-0044	1	0584	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2008	118	342	36.2	35.9	31.9	31.8	29.5	13.41	Y	0
21-111-0044	1	0584	Louisville	Jefferson	1032 BEECHER AVE, WYANDOTTE PARK	2009	118	353	33.8	28.3	28.0	27.3	25.7	12.45		0
21-111-0048	1	0549	Louisville	Jefferson	850 BARRET AVENUE	2000	118	108	38.6	37.7	37.5	36.6	37.5	16.71*		0
21-111-0048	1	0549	Louisville	Jefferson	850 BARRET AVENUE	2001	118	109	55.9	43.7	42.6	40.2	42.6	16.90*		0
21-111-0048	1	0549	Louisville	Jefferson	850 BARRET AVENUE	2002	118	103	52.1	45.8	44.7	38.0	44.7	16.43		0
21-111-0048	1	0549	Louisville	Jefferson	850 BARRET AVENUE	2003	118	108	43.0	42.1	35.5	32.5	35.5	15.53	Y	0
21-111-0048	1	0549	Louisville	Jefferson	850 BARRET AVENUE	2004	118	109	42.7	30.4	28.8	28.3	28.8	13.71*		5
21-111-0048	1	0549	Louisville	Jefferson	850 BARRET	2005	118	114	46.4	43.6	43.2	41.6	43.2	16.72		5

Note: The * indicates that the mean does not satisfy summary criteria.

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					AVENUE											
21-111-0048	1	0549	Louisville	Jefferson	850 BARRET AVENUE	2006	118	119	40.9	37.6	36.7	33.4	36.7	13.87	Y	5
21-111-0048	1	0584	Louisville	Jefferson	850 BARRET AVENUE	2007	118	116	42.9	40.4	31.9	31.3	31.9	14.96	Y	5
21-111-0048	1	0584	Louisville	Jefferson	850 BARRET AVENUE	2008	118	116	35.0	31.3	30.7	25.1	30.7	13.44	Y	0
21-111-0051	1	0549	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2000	118	55	37.8	36.4	34.9	33.3	36.4	16.80*		0
21-111-0051	1	0549	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2001	118	51	37.9	37.6	32.4	29.7	37.6	16.27*		0
21-111-0051	1	0549	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2002	118	50	30.5	29.6	28.8	28.3	30.5	15.72*		0
21-111-0051	1	0549	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2003	118	57	37.3	33.0	31.1	29.8	33.0	14.92	Y	0
21-111-0051	1	0549	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2004	118	60	29.3	25.8	24.2	23.7	25.8	12.63		0
21-111-0051	1	0549	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2005	118	59	39.1	36.5	30.0	29.2	36.5	16.48		5
21-111-0051	1	0549	Louisville	Jefferson	7201 WATSON	2006	118	58	32.8	32.5	28.4	26.2	32.5	13.67	Y	5

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PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					LN, WATSON LN ELEMENTARY SCH											
21-111-0051	1	0584	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2007	118	59	51.3	32.5	32.0	30.7	32.5	15.37	Y	5
21-111-0051	1	0584	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2008	118	57	30.3	28.6	24.6	24.4	28.6	12.78	Y	0
21-111-0051	1	0584	Louisville	Jefferson	7201 WATSON LN, WATSON LN ELEMENTARY SCH	2009	118	61	26.7	24.7	24.5	22.4	24.7	11.59		0
21-111-0067	1	0584	Not in a city	Jefferson	2730 CANNONS LANE, BOWMAN FIELD	2009	118	122	30.8	27.2	24.1	24.0	24.1	11.67		0
21-111-1041	1	0549	Louisville	Jefferson	4201 ALGONQUIN PKWY	2001	118	330	60.8	49.9	49.9	47.9	43.8	18.74		0
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2000	118	118	38.9	38.4	37.2	36.9	37.2	16.26		5
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2001	118	112	51.5	44.6	40.2	39.3	40.2	15.25	Y	5
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2002	118	107	39.5	38.0	37.8	37.4	37.8	15.06*	Y	0

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2003	118	107	31.9	31.9	30.8	29.6	30.8	14.30	Y	0
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2004	118	115	38.1	37.4	29.4	28.2	29.4	13.42	Y	0
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2005	118	118	52.7	46.8	42.1	40.4	42.1	15.86		5
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2006	118	116	36.7	32.7	32.6	32.2	32.6	13.29		5
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2007	118	117	34.7	34.6	31.6	30.5	31.6	13.99		5
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2008	118	121	30.5	27.3	25.2	25.0	25.2	11.99	Y	0
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2009	118	116	24.5	23.3	23.1	22.1	23.1	11.15		0
21-125-0004	1	0584	London	Laurel	LONDON AIRPORT	2002	118	47	31.6	27.3	24.5	23.5	31.6	13.02*	Y	0
21-125-0004	1	0584	London	Laurel	LONDON AIRPORT	2003	118	55	28.3	24.5	23.1	21.8	24.5	12.11*	Y	0

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-125-0004	1	0584	London	Laurel	LONDON AIRPORT	2004	118	57	28.5	21.5	20.0	19.0	21.5	11.47	Y	0
21-125-0004	1	0584	London	Laurel	LONDON AIRPORT	2005	118	55	38.4	29.5	27.5	27.4	29.5	14.07		5
21-125-0004	1	0584	London	Laurel	LONDON AIRPORT	2006	118	8	16.2	11.0	11.0	10.1	16.2	9.00*		0
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2000	118	92	37.5	35.3	34.4	29.6	35.3	15.26*		5
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2001	118	106	34.1	33.0	28.1	27.2	28.1	14.11	Y	0
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2002	118	103	44.3	34.4	30.2	28.3	30.2	12.61*	Y	0
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2003	118	102	43.6	36.3	31.0	29.3	31.0	13.75	Y	0
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2004	118	117	27.7	27.0	26.5	26.3	26.5	11.77	Y	0
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2005	118	119	39.6	37.2	37.1	36.9	37.1	14.03		5
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2006	118	119	39.3	38.9	36.7	31.4	36.7	13.61		5
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2007	118	114	36.8	34.2	33.9	31.0	33.9	13.89		5
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH	2008	118	117	26.4	25.7	25.3	25.3	25.3	11.80	Y	0

Note: The * indicates that the mean does
not satisfy summary criteria.

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					MIDDLE SCHOOL											
21-145-1004	1	0584	Paducah	McCracken	342 LONE OAK RD, PADUCAH MIDDLE SCHOOL	2009	145	116	30.9	25.2	25.1	25.1	25.1	11.53		0
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2000	118	116	37.3	31.2	29.9	28.8	29.9	14.93		5
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2001	118	105	50.6	30.5	29.9	28.6	29.9	13.85	Y	5
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2002	118	109	49.8	34.6	33.7	32.8	33.7	13.46	Y	0
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2003	118	112	31.3	31.2	28.1	26.3	28.1	12.93	Y	0
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2004	118	111	33.7	28.6	28.4	27.0	28.4	12.98	Y	0
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2005	118	115	42.3	35.2	32.6	31.7	32.6	15.21		5
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2006	118	118	32.4	28.6	28.2	26.9	28.2	12.31		0
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2007	118	118	44.7	35.6	31.9	31.8	31.9	13.32		5
21-151-0003	1	0584	Richmond	Madison	MAYFIELD SCHOOL, BOND STREET	2008	118	119	25.3	23.5	23.5	20.8	23.5	10.45	Y	0
21-151-0003	1	0584	Richmond	Madison	MAYFIELD	2009	118	114	18.9	18.7	18.5	18.4	18.5	9.76		0

Note: The * indicates that the mean does not satisfy summary criteria.

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					SCHOOL, BOND STREET											
21-183-0032	1	0584	Not in a city	Ohio	KEYTOWN ROAD	2005	118	48	34.5	33.1	29.2	28.0	34.5	14.85*	Y	5
21-183-0032	1	0584	Not in a city	Ohio	KEYTOWN ROAD	2006	118	55	25.0	24.2	22.6	22.5	24.2	12.67		0
21-183-0032	1	0584	Not in a city	Ohio	KEYTOWN ROAD	2007	118	56	43.6	38.6	26.1	23.6	38.6	14.40		5
21-183-0032	1	0584	Not in a city	Ohio	KEYTOWN ROAD	2008	118	60	28.0	25.4	24.1	21.4	25.4	12.07	Y	0
21-183-0032	1	0584	Not in a city	Ohio	KEYTOWN ROAD	2009	145	54	25.8	25.6	24.5	20.3	25.6	11.08		0
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2000	118	36	34.9	33.7	33.6	33.4	34.9	17.95*		5
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2001	118	55	36.5	28.0	28.0	26.6	28.0	14.33	Y	0
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2002	118	50	25.4	23.2	22.0	21.2	25.4	13.03*	Y	0
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2003	118	57	37.3	28.3	22.5	22.5	28.3	13.30	Y	0
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2004	118	61	27.9	24.7	21.0	19.7	24.7	11.94	Y	0
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2005	118	55	34.6	31.4	26.4	25.8	31.4	13.87	Y	5
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2006	118	58	29.9	26.9	22.7	21.8	26.9	12.36		5
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2007	118	57	38.0	31.2	27.8	26.5	31.2	14.03		5
21-193-0003	1	0584	Hazard	Perry	PERRY COUNTY HORSE PARK	2008	118	25	22.5	20.0	16.5	14.8	22.5	10.97*	Y	0
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2000	118	106	32.7	31.5	31.3	30.9	31.3	14.78		5
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL,	2001	118	108	44.5	34.1	31.9	30.5	31.9	14.49	Y	5

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PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
					DOT DISTRICT OFFIC											
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2002	118	119	41.7	38.2	29.7	29.0	29.7	13.58	Y	0
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2003	118	114	62.2	43.0	30.5	29.5	30.5	13.13	Y	0
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2004	118	120	36.5	29.7	28.2	25.4	28.2	12.34	Y	0
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2005	118	120	43.7	34.1	32.0	30.0	32.0	14.14	Y	5
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2006	118	120	32.2	30.9	29.4	28.3	29.4	13.44		0
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2007	118	119	39.6	38.1	33.0	32.6	33.0	14.19		5
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT OFFIC	2008	118	85	25.8	21.2	19.7	18.0	21.2	10.49	Y	0
21-195-0002	1	0584	Pikeville	Pike	101 NORTH MAYO TRAIL, DOT DISTRICT	2009	118	87	35.7	23.5	20.1	17.3	23.5	9.45		0

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN OFFIC	2000	118	116	41.8	33.8	32.6	32.3	32.6	15.24		5
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN	2001	118	118	37.0	33.5	31.5	30.1	31.5	14.77	Y	0
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN	2002	118	119	32.0	31.0	29.1	26.7	29.1	13.27	Y	0
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN	2003	118	107	36.2	32.7	30.2	29.1	30.2	13.31	Y	0
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN	2004	118	115	34.7	32.8	31.5	29.2	31.5	13.14	Y	0
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN	2005	118	117	38.9	35.1	32.5	31.5	32.5	14.82		5
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN	2006	118	117	37.3	35.0	34.8	30.6	34.8	13.83		0
21-227-0007	1	0584	Bowling Green	Warren	KEREIAKES PARK, FAIRVIEW & COLLETT LN	2007	118	80	44.2	38.0	37.5	34.9	38.0	16.63*		5

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Feb. 19, 2010

PM2.5 - Local Conditions (88101) Kentucky Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-227-0008	1	0584	Oakland	Warren	OAKLAND ELEMENTARY SCH, KY 179, OAKLAND	2007	118	39	37.5	22.4	20.9	19.5	37.5	12.54*		5
21-227-0008	1	0584	Oakland	Warren	OAKLAND ELEMENTARY SCH, KY 179, OAKLAND	2008	118	115	29.2	28.9	28.6	25.3	28.6	12.16	Y	0
21-227-0008	1	0584	Oakland	Warren	OAKLAND ELEMENTARY SCH, KY 179, OAKLAND	2009	145	111	26.5	26.0	21.0	17.8	21.0	10.55		0

Note: The * indicates that the mean does not satisfy summary criteria.

Feb. 19, 2010

METHODS USED IN THIS REPORT

PARAMETER	METHOD CODE	COLLECTION METHOD	ANALYSIS METHOD
88101	118	R & P Model 2025 PM2.5 Sequential w/WINS	GRAVIMETRIC
88101	145	R & P Model 2025 PM-2.5 Sequential Air Sample:	Gravimetric

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not satisfy summary criteria.

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PQAOS USED IN THIS REPORT

PQAO	AGENCY DESCRIPTION
0549	Jefferson County, KY Air Pollution Control District
0584	Kentucky Division For Air Quality

Note: The * indicates that the mean does
not satisfy summary criteria.

UNITES STATES ENVIRONMENTAL PROTECTION AGENCY

User ID: NOQ

QUICKLOOK CRITERIA PARAMETERS

Report Request ID: 720857 Report Code: AMP450 Feb. 19, 2010

GEOGRAPHIC SELECTIONS

Tribal State	County	Site	Parameter	POC	City	AQCR	UAR	CBSA	CSA	EPA Region	Method	Duration	Begin Date	End Date
39	017													
39	025													
39	061													
39	087													
39	145													
39	165													

PROTOCOL SELECTIONS

Parameter Classification	Parameter	Method	Duration
CRITERIA	88101		

SELECTED OPTIONS

Option Type	Option Value
EVENTS PROCESSING	EXCLUDE REGIONALLY CONCURRED EVENTS
MERGE PDF FILES	YES

SORT ORDER

Order	Column
1	PARAMETER_CODE
2	STATE_CODE
3	COUNTY_CODE
4	SITE_ID
5	POC
6	DATES
7	EDT_ID

GLOBAL DATES

Start Date	End Date
2000	2009

Feb. 19, 2010

EXCEPTIONAL DATA TYPES

EDT	DESCRIPTION
0	NO EVENTS
1	EVENTS EXCLUDED
2	EVENTS INCLUDED
3	EXCEPTIONAL EVENTS EXCLUDED
4	NATURAL EVENTS EXCLUDED
5	EVENTS WITH CONCURRENCE EXCLUDED
6	EXCEPTIONAL EVENTS WITH CONCURRENCE EXCLUDED
7	NATURAL EVENTS WITH CONCURRENCE EXCLUDED

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not satisfy summary criteria.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2000	120	312	43.8	42.2	42.1	41.3	38.1	16.96		0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2001	120	345	49.9	47.8	44.9	44.4	41.7	16.43		0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2002	120	339	48.1	44.8	43.0	42.3	40.7	16.83	Y	0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2003	120	310	48.1	47.4	46.6	44.6	38.6	15.05*	Y	0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2004	000	60	39.5	37.2	31.6	28.4	37.2	14.06	Y	0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2005	119	37	47.6	43.1	35.8	28.0	47.6	19.04*	Y	0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2006	119	59	31.5	30.2	26.7	24.1	30.2	14.05	Y	0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2007	120	118	37.8	37.1	36.8	35.3	36.8	15.41		0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2008	120	119	38.4	31.2	27.1	26.3	27.1	13.69	Y	0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2009	000	116	31.5	27.4	25.3	24.3	25.3	12.68		0
39-017-0003	2	1259	Middletown	Butler	BONITA & ST JOHN	2003	120	21	38.7	27.1	26.5	24.8	38.7	17.20*	Y	0
39-017-0003	2	1259	Middletown	Butler	BONITA & ST JOHN	2008	000	58	38.1	30.9	27.3	27.2	30.9	14.32	Y	0
39-017-0003	2	1259	Middletown	Butler	BONITA & ST JOHN	2009	000	58	29.9	22.8	22.2	21.9	22.8	12.41		0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2000	120	30	43.8	39.0	36.5	32.2	43.8	18.85*		0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2001	120	114	45.5	42.9	41.5	36.1	41.5	15.87		0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2002	120	115	39.2	35.1	33.6	32.2	33.6	15.34	Y	0

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2003	120	115	48.0	35.3	34.8	34.5	34.8	15.83	Y	0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2004	120	120	39.9	32.2	32.2	30.6	32.2	14.65	Y	0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2005	120	122	56.3	53.5	43.4	38.9	43.4	17.88	Y	0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2006	120	115	35.7	35.6	35.2	30.8	35.2	13.99	Y	0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2007	120	115	38.0	36.8	34.5	34.0	34.5	14.94		0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2008	120	118	39.5	32.7	31.5	27.6	31.5	13.75	Y	0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2009	000	113	33.0	29.5	27.2	25.5	27.2	13.08		0
39-017-0017	1	1259	Middletown	Butler	3300 WILWOOD	2000	120	30	38.7	38.2	37.4	28.2	38.7	17.93*		0
39-017-0017	1	1259	Middletown	Butler	3300 WILWOOD	2001	120	122	48.9	45.0	44.8	39.9	44.8	15.79		0
39-017-0017	1	1259	Middletown	Butler	3300 WILWOOD	2002	120	120	40.2	38.3	33.8	33.6	33.8	15.51	Y	0
39-017-0017	1	1259	Middletown	Butler	3300 WILWOOD	2003	120	102	39.4	34.7	34.6	31.7	34.6	14.66*	Y	0
39-017-0017	1	1259	Middletown	Butler	3300 WILWOOD	2004	120	121	37.9	35.6	34.3	32.0	34.3	14.20	Y	0
39-017-0017	1	1259	Middletown	Butler	3300 WILWOOD	2005	120	122	49.7	49.7	44.9	42.0	44.9	17.23	Y	0
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2001	119	5	16.5	11.9	11.7	9.0	16.5	11.62*		0
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2002	119	59	32.3	30.9	28.6	27.0	30.9	13.85	Y	0
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2003	119	61	33.5	33.0	31.7	30.7	33.0	14.99	Y	0
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2004	119	120	36.3	32.3	31.6	29.8	31.6	13.57	Y	0
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2005	119	122	47.1	46.5	45.4	40.3	45.4	16.87	Y	0

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PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2006	120	122	36.0	35.0	32.7	29.7	32.7	13.38	Y	0
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2007	120	112	37.6	36.9	36.4	35.5	36.4	14.63		0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2005	120	114	40.8	38.9	38.3	35.5	38.3	15.73	Y	0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2006	120	117	34.2	31.9	31.6	30.9	31.6	12.72	Y	0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2007	120	114	40.8	34.1	33.5	33.1	33.5	14.01		0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2008	120	116	25.3	24.5	23.6	23.5	23.6	11.75	Y	0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2009	120	121	23.5	22.4	22.0	21.8	22.0	11.01		0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2005	120	118	47.4	46.6	45.0	41.0	45.0	16.61	Y	0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2006	120	118	35.0	34.6	33.3	31.8	33.3	13.29	Y	0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2007	120	296	40.8	39.2	38.1	37.2	34.7	14.63		0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2008	120	174	33.9	28.1	28.1	27.0	27.0	12.48	Y	0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2009	120	122	29.7	26.3	24.2	23.9	24.2	12.11		0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2000	120	323	49.7	49.4	47.6	46.7	44.3	19.25		0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2001	120	327	53.2	52.5	52.0	49.4	44.5	18.16*		0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2002	120	351	50.6	48.0	46.2	46.0	43.7	17.89	Y	0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2003	120	357	46.5	46.5	44.5	42.7	37.8	16.95	Y	0

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PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2004	120	61	47.4	42.0	35.2	27.7	42.0	15.91	Y	0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2005	120	58	43.3	38.5	38.1	32.9	38.5	19.75	Y	0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2006	120	58	36.3	35.2	31.5	27.1	35.2	15.51	Y	0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2007	120	109	41.5	38.1	36.5	36.2	36.5	16.59		0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2008	120	119	37.7	33.3	33.0	31.7	33.0	15.12	Y	0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2009	120	355	34.3	33.9	29.5	29.1	27.1	13.40		0
39-061-0014	2	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2001	120	22	44.6	33.4	32.6	32.2	44.6	23.00*		0
39-061-0014	2	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2008	000	58	40.1	34.7	33.0	32.1	34.7	15.25	Y	0
39-061-0014	2	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2009	119	62	35.3	31.1	30.4	25.1	31.1	13.89		0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2000	120	115	40.6	40.1	34.3	34.0	34.3	16.72		0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2001	120	117	51.3	44.5	41.2	40.9	41.2	15.93		0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2002	120	118	39.2	38.7	37.7	36.4	37.7	15.29	Y	0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2003	120	118	35.8	34.4	31.9	31.6	31.9	15.50	Y	0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2004	120	115	41.6	37.3	30.5	29.1	30.5	14.63	Y	0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2005	120	115	52.1	50.0	45.8	41.3	45.8	17.53	Y	0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2006	120	121	34.5	33.7	32.8	32.3	32.8	13.57	Y	0

Note: The * indicates that the mean does not satisfy summary criteria.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Feb. 19, 2010

PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2007	120	107	41.9	35.3	34.7	33.1	34.7	15.09		0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2008	000	107	31.5	26.6	25.5	25.0	25.5	12.62	Y	0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2009	142	116	28.5	25.7	24.8	24.8	24.8	12.73		0
39-061-0040	2	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2002	000	108	39.4	38.1	37.3	37.2	37.3	15.74*	Y	0
39-061-0041	1	1259	Cincinnati	Hamilton	5300 WINNESTE AVE.	2000	120	63	42.0	38.0	30.4	27.7	38.0	15.88*		0
39-061-0041	1	1259	Cincinnati	Hamilton	5300 WINNESTE AVE.	2001	120	117	53.7	46.2	41.9	41.4	41.9	16.11		0
39-061-0041	1	1259	Cincinnati	Hamilton	5300 WINNESTE AVE.	2002	120	119	39.7	38.5	33.6	31.9	33.6	15.10	Y	0
39-061-0041	1	1259	Cincinnati	Hamilton	5300 WINNESTE AVE.	2003	120	119	37.2	34.7	34.4	32.0	34.4	15.30	Y	0
39-061-0041	1	1259	Cincinnati	Hamilton	5300 WINNESTE AVE.	2004	120	108	42.6	42.4	32.2	30.3	32.2	14.63*	Y	0
39-061-0041	1	1259	Cincinnati	Hamilton	5300 WINNESTE AVE.	2005	120	51	49.2	37.4	28.7	27.3	37.4	15.77*	Y	0
39-061-0041	2	1259	Cincinnati	Hamilton	5300 WINNESTE AVE.	2000	120	14	43.7	43.3	33.4	29.3	43.7	19.75*		0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2000	120	25	44.8	43.9	40.0	37.5	44.8	20.61*		0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2001	120	116	56.1	47.7	46.6	41.4	46.6	17.63		0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2002	120	119	51.6	40.1	40.0	39.0	40.0	16.83	Y	0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2003	120	119	34.3	33.8	33.8	33.6	33.8	16.69	Y	0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2004	120	122	43.0	41.9	31.9	30.7	31.9	15.99	Y	0

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Feb. 19, 2010

PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2005	120	106	58.9	45.8	44.4	38.7	44.4	19.09*	Y	0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2006	120	122	39.4	37.0	34.5	33.5	34.5	14.94	Y	0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2007	120	110	39.2	36.3	35.9	33.6	35.9	15.90		0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2008	120	111	33.5	32.2	27.5	27.5	27.5	14.40	Y	0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2009	000	109	36.5	28.2	27.0	26.3	27.0	13.71		0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2000	120	30	41.2	40.8	39.5	33.7	41.2	19.10*		0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2001	120	113	46.2	45.9	40.1	39.0	40.1	16.07		0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2002	120	121	38.8	37.2	34.8	34.1	34.8	15.42	Y	0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2003	120	119	37.7	37.4	37.3	33.2	37.3	15.67	Y	0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2004	120	116	42.4	35.8	31.4	30.2	31.4	14.92	Y	0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2005	120	103	48.4	47.2	39.9	38.4	39.9	16.89*	Y	0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2006	120	118	39.0	35.8	34.9	32.2	34.9	14.47	Y	0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2007	120	116	37.2	34.0	34.0	32.6	34.0	14.85		0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2008	120	117	35.0	28.5	28.2	28.0	28.2	13.32	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2000	120	265	44.2	42.0	41.8	39.8	39.1	17.24*		0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2001	120	337	53.4	53.2	48.8	48.7	42.3	16.76		0

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24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2002	120	357	48.3	45.3	43.4	43.3	40.7	16.08	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2003	120	338	44.0	43.8	42.4	40.2	37.1	16.01	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2004	120	350	43.4	40.8	39.3	37.3	34.6	15.33	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2005	120	119	54.4	51.8	47.1	43.4	47.1	18.37	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2006	120	111	34.9	34.0	34.0	33.0	34.0	14.37	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2007	120	111	40.9	35.0	33.7	32.0	33.7	15.09		0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2008	000	112	34.2	31.9	30.3	28.9	30.3	13.74	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2009	142	119	30.5	27.8	25.7	25.7	25.7	12.97		0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2000	120	103	48.2	46.1	40.8	40.4	40.8	19.27*		0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2001	120	108	45.5	37.2	37.0	36.7	37.0	17.02*		0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2002	120	121	51.4	41.8	40.1	36.9	40.1	16.98	Y	0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2003	120	118	41.1	36.4	35.8	35.4	35.8	17.31	Y	0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2004	120	112	46.8	42.8	33.9	30.3	33.9	16.39	Y	0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2005	120	110	54.8	53.9	51.4	42.2	51.4	20.00	Y	0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2006	120	114	37.9	36.8	36.1	34.7	36.1	15.90	Y	0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2007	120	110	37.4	36.3	35.4	32.8	35.4	16.07		0

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SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2008	120	115	37.4	31.8	31.0	30.8	31.0	14.40	Y	0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2009	120	117	30.8	30.8	28.7	28.5	28.7	13.44		0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2000	120	95	51.6	40.2	35.6	35.2	40.2	17.35*		0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2001	120	108	57.5	47.8	41.0	38.7	41.0	17.67		0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2002	120	118	51.3	44.2	42.4	38.1	42.4	15.48	Y	0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2003	120	117	33.7	30.7	29.3	27.8	29.3	14.25	Y	0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2004	120	117	33.7	32.7	31.2	28.8	31.2	13.71	Y	0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2005	120	118	46.5	42.3	38.5	35.3	38.5	16.97	Y	0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2006	120	119	42.8	34.7	30.8	30.1	30.8	14.39	Y	0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2007	120	118	44.8	40.0	35.2	34.8	35.2	14.97		0
39-087-0010	1	0880	Ironton	Lawrence	2128 S. 9TH	2008	120	11	16.5	15.4	14.7	12.2	16.5	10.84*	Y	0
39-087-0012	1	0880	Ironton	Lawrence	450 Commerce Drive	2008	120	98	30.5	27.6	26.0	25.9	27.6	13.12	Y	0
39-087-0012	1	0880	Ironton	Lawrence	450 Commerce Drive	2009	120	116	28.8	21.9	21.4	20.2	21.4	11.33		0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2000	120	66	55.8	43.5	38.5	38.1	43.5	21.11*		0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2001	120	117	68.4	57.5	49.2	44.0	49.2	20.32		0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2002	120	118	50.9	43.5	42.1	35.8	42.1	16.65	N	0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2003	120	117	36.0	33.8	32.8	30.1	32.8	14.69	Y	0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2004	120	118	37.3	30.5	29.4	27.8	29.4	12.95	Y	0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2005	120	120	44.0	40.7	40.3	35.2	40.3	16.24	Y	0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2006	120	120	52.4	41.9	30.5	29.0	30.5	14.32	Y	0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2007	120	120	41.8	38.8	37.5	33.8	37.5	13.99		0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2008	120	347	31.7	30.8	27.8	26.0	24.4	12.15	Y	0
39-145-0013	1	0880	New Boston	Scioto	4862 GALLIA	2009	120	115	24.0	23.5	21.8	21.0	21.8	10.88		0

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PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

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39-145-0013	2	0880	New Boston	Scioto	4862 GALLIA	2008	120	58	25.2	24.4	22.9	21.9	24.4	11.74		0
39-145-0013	2	0880	New Boston	Scioto	4862 GALLIA	2009	120	55	21.8	21.0	20.0	16.9	21.0	10.30*		0
39-165-0007	1	1259	Lebanon	Warren	416 SOUTHEAST ST.	2007	120	114	40.8	36.6	33.6	33.3	33.6	13.98		0
39-165-0007	1	1259	Lebanon	Warren	416 SOUTHEAST ST.	2008	120	118	27.7	25.7	24.2	23.3	24.2	11.92	Y	0
39-165-0007	1	1259	Lebanon	Warren	416 SOUTHEAST ST.	2009	120	119	26.5	25.6	23.6	22.4	23.6	11.70		0

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not satisfy summary criteria.

Feb. 19, 2010

METHODS USED IN THIS REPORT

PARAMETER	METHOD CODE	COLLECTION METHOD	ANALYSIS METHOD
88101	000	MULTIPLE METHODS	MULTIPLE METHODS
88101	119	Andersen RAAS2.5-100 PM2.5 SAM w/WINS	GRAVIMETRIC
88101	120	Andersen RAAS2.5-300 PM2.5 SEQ w/WINS	GRAVIMETRIC
88101	142	BGI Models PQ200-VSCC or PQ200A-VSCC	Gravimetric

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not satisfy summary criteria.

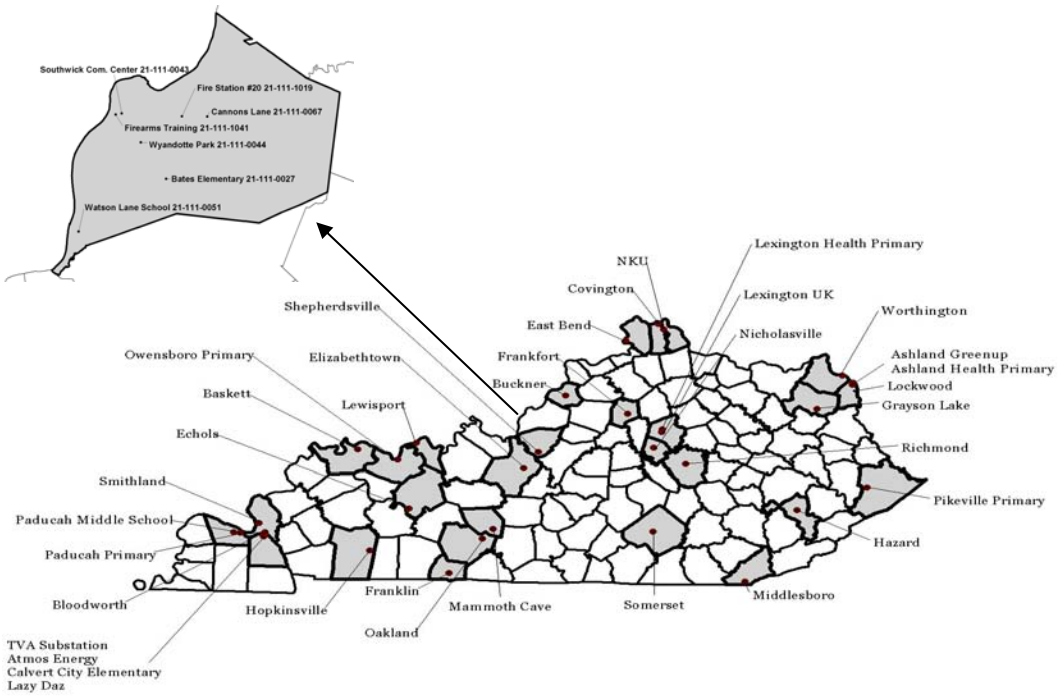
Feb. 19, 2010

PQAOS USED IN THIS REPORT

PQAO	AGENCY DESCRIPTION
0880	Portsmouth City Health Dept Division Air Pollution Control
1259	Hamilton County Department Of Environmental Services

Note: The * indicates that the mean does not satisfy summary criteria.

Kentucky Annual Ambient Air Monitoring Network Plan 2009



Commonwealth of Kentucky Energy & Environment Cabinet
Department for Environmental Protection
Division for Air Quality
200 Fair Oaks Lane, 1st Floor,
Frankfort, Kentucky 40601

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CERTIFICATION

By the signatures below, the Kentucky Division for Air Quality certifies that the information contained in this Surveillance Network document for sampling year 2009 is complete and accurate at the time of submittal to EPA Region 4. However, due to circumstances that may arise during the sampling year, some network information may change. A notification of change and a request for approval will be submitted to EPA Region 4 at that time.

Print Name: Andrea P. Keatley — Signature: [signature] — Date: 6/30/09
Environmental Scientist II

Print Name: Stephanie McCarthy — Signature: Stephanie McCarthy — Date: 6/30/09
Technical Services Branch Manager

Print Name: John S. Lyons — Signature: John S Lyons — Date: 6/30/09
Division Director

PUBLIC NOTIFICATION AND COMMENT PERIOD

In accordance with 40 C.F.R. 58.10(a)(1), the Kentucky Energy and Environment Cabinet shall make the annual monitoring network plan available for public inspection for at least 30 days prior to submission to the U.S. EPA. The annual monitoring network plan details the operation and location of ambient air monitors operated by the Kentucky Division for Air Quality (KYDAQ), Louisville Metro Air Pollution Control District (LMAPCD), and the National Park Service (NPS).

TABLE OF CONTENTS

ACRONYMS

AEM – Automated Equivalent Method

AQI – Air Quality Index

AQS – Air Quality System

ARM – Automated Reference Method

CBSA – Core-Based Statistical Area

CSA – Combined Statistical Area

FAM – Federal Alternate Method

FEM – Federal Equivalent Method

FRM – Federal Reference Method

KYDAQ – Kentucky Division for Air Quality

LMAPCD – Louisville Metro Air Pollution Control District

MSA – Metropolitan Statistical Area

NAAQS – National Ambient Air Quality Standards

NAMS – National Air Monitoring Stations

SAMWG – Standing Air Monitoring Working Group

SLAMS – State and Local Air Monitoring Stations

SPM – Special Purpose Monitors

U.S.EPA – United States Environmental Protection Agency

UV – Ultra Violet

VOC – Volatile Organic Compounds

INTRODUCTION

In October 1975, the United States Environmental Protection Agency (U.S.EPA) established a work group to critically review and evaluate current air monitoring activities at that time. This group was named the Standing Air Monitoring Working Group (SAMWG). The review by the SAMWG indicated several areas where deficiencies existed which needed correction. The principal areas needing correction were: an excess of monitoring sites in some areas to assess air quality; existing regulations did not allow for flexibility to conduct special purpose monitoring studies; data reporting was untimely and incomplete, caused by a lack of uniformity in station location and probe siting, sampling methodology, quality assurance practices, and data handling procedures.

In August 1978, recommendations developed by SAMWG, to remedy the deficiencies in the existing monitoring activities, were combined with the new requirements of Section 319 of the Clean Air Act. Section 319 provided for the development of uniform air quality monitoring criteria and methodology; reporting of a uniform air quality index in major urban areas; and the establishment of an air quality monitoring system nationwide which utilizes uniform monitoring criteria and provides for monitoring stations in major urban areas that supplement State monitoring. The combination of the recommendations and requirements were included in a proposed revision to the air monitoring regulations.

In May 1979, air monitoring regulations were finalized by the U.S.EPA requiring certain modifications and additions to be included in the State Implementation Plan for air quality surveillance. These regulations require each state to operate a network of monitoring stations designated as State and Local Air Monitoring Stations (SLAMS) that measure ambient concentrations of air pollutants for which standards have been established. The SLAMS designation contains provisions concerning the conformity to specific siting and monitoring criteria not previously required. The regulations also provide for an annual review of the monitoring network to insure objectives are being met and to identify needed modification.

The Kentucky Division for Air Quality (KYDAQ) has operated an air quality monitoring network in the Commonwealth since July 1967. The Louisville Metro Air Pollution Control District (LMAPCD), a local agency, has maintained a sub-network in its area of jurisdiction since January 1956. Since that time, the networks have been expanded in accordance with the U.S.EPA's regulations to consist of a current overall network of 44 stations, operated by KYDAQ, LMAPCD and the National Park Service. The Commonwealth's SLAMS air monitoring network monitors criteria pollutants for which the National Ambient Air Quality Standards (NAAQS) have been issued. In addition to a SLAMS network, KYDAQ's air monitoring network includes special purpose monitors (SPM) for air toxics, mercury, wet deposition and meteorological stations.

The annual monitoring network description, as provided for in 40 CFR Part 58.10, *Annual monitoring network plan and periodic network assessment*, must contain the following information for each monitoring station in the network:

1. The Air Quality System (AQS) site identification number for existing stations.

2. The location, including the street address and geographical coordinates, for each monitoring station.

3. The sampling and analysis method used for each measured parameter.

4. The operating schedule for each monitor.

5. Any proposal to remove or move a monitoring station within a period of eighteen months following the plan submittal.

6. The monitoring objective and spatial scale of representativeness for each monitor.

7. The identification of any site that is suitable for comparison against the PM2.5 NAAQS.

8. The Metropolitan Statistical Area (MSA), Core-Based Statistical Area (CBSA), Combined Statistical Area (CSA) or other area represented by the monitor.

The following document constitutes the Kentucky ambient air monitoring network description and is organized into three main parts:

(1) Station Description Format: An outline of the designations, parameters, monitoring methods, and the basis for site selection.

(2) Network Summaries: Presenting the total number of sites and monitors in each region and for the state. Also included is a listing of all proposed changes to the current network.

(3) Air Monitoring Station Description: Each air monitor station is described in detail as per the outline in (1) above.

Modification to the network as determined by an annual review process will be made each year to maintain a current up-to-date network description document.

STATION DESCRIPTION FORMAT

AQS Site Identification Information

Pertinent, specific siting information for each site and monitor is stored in the U.S. EPA's AQS data system. This information includes the exact location of the site, local and regional population, description of the site location, monitor types, and monitoring objectives. This site and monitor information is routinely updated whenever there is a change in site characteristics or pollutants monitored.

Network Station Description

The network station descriptions contained in this document include the following information:

1. Site Description

Specific information is provided to show the location of the monitoring equipment at the site, if the site is located in a CSA/MSA, the AQS identification number, the GPS coordinates, and that monitors and monitor probes conform to the siting criteria.

2. Date Established

The date when each existing monitoring station was established is shown in the description. For those stations, which are proposed, a date is provided when it is expected for the station to be in operation.

3. Site Approval Status

Each monitoring station in the existing network has been reviewed with the purpose of determining whether it meets all design criteria for inclusion in the SLAMS network. Stations that do not meet the criteria will either be relocated in the immediate area or when possible, re-sited at the present location.

4. Monitoring Objectives

The monitoring network was designed to provide information to be used as a basis for the following actions:

(a) To determine compliance with ambient air quality standards and to plan measures to attain these standards.

(b) To activate emergency control procedures in the event of an impending air pollution episode.

(c) To observe pollution trends throughout a region including rural areas and report progress made toward meeting ambient air quality standards.

(d) To provide a database for the evaluation of the effects of air quality on population, land use, and transportation planning; to provide a database for the development and evaluation of air dispersion models.

5. Monitoring Stations' Designations

Most stations described in the air quality surveillance network are designated as "SLAMS". In addition, some of these stations fulfill other requirements, which must be identified. In this description of the network, designations are also made for Special Purpose Monitors (SPM), Emergency Episode Monitoring sites and Air Quality Index sites (AQI). The following is the criteria used for each of these designations.

SLAMS: Requirements for air quality surveillance systems provide for the establishment of a network of monitoring stations designated as State and Local Air Monitoring Stations (SLAMS) that measure ambient concentrations of pollutants for which standards have been established. These stations must meet requirements that relate to four major areas: quality assurance, monitoring methodology, sampling interval, siting of instruments and instrument probes.

EMERGENCY EPISODE MONITORING SITES (EPISODE): Regulations provide for the operation of at least one continuous SLAMS monitor for each major pollutant in designated locations for emergency episode monitoring. These monitors are placed in areas of worst air quality and provide continual surveillance during episode conditions.

AIR QUALITY INDEX (AQI): Certain stations in the SLAMS network provide data for daily index reporting. Index reporting is required for all urban areas with a population exceeding 200,000. However, KYDAQ is providing this service to the general public from all areas where monitoring and attending staff are available. The AQI is a method of reporting that converts concentration levels of pollution to a simple number scale of 0-500. Intervals on the AQI scale are related to potential health effects of the daily measured concentrations of the major pollutants. KYDAQ prepares the Index twice daily for release to the public from the pollutant data reported from the Field Offices.

SPM: Not all monitors and monitoring stations in the air quality surveillance network are included in the SLAMS network. In order to allow the capability of providing monitoring for complaint studies, modeling verification and compliance status, certain monitors are reserved for short-term studies and designated as Special Purpose Monitors (SPM). These monitors are not committed to any one location or for any specified time period. They may be located as separate monitoring stations or be included at SLAMS locations. Monitoring data may be reported, provided that the monitors and stations conform to all requirements of the SLAMS network.

6. Monitoring Methods

All sampling and analytical procedures used in the air-monitoring network conform to Federal reference (FRM), alternate (FAM) or equivalent (FEM) methods. In case there is no federal method, procedures are described in the Kentucky Air Quality Monitoring and Quality Assurance Manuals.

(a) Particulate Matter 10 microns in size (PM_{10})

All PM_{10} samplers operated by the Division for Air Quality are certified as either FRM or FEM samplers and are operated according to the requirements set forth in 40 CFR 50 and 40 CFR 53.

Intermittent samplers collect a 24-hour sample every sixth day on 46.2mm PTFE filters. The filter is weighed before and after the sample run. The gain in weight in relation to the volume of air sampled is calculated in micrograms per cubic meter (ug/m^3). The PTFE filters are to be equilibrated before each weighing for a minimum of 24 hours at a 20-23 degrees C mean temperature and a 30-40% mean relative humidity.

Continuous PM_{10} samplers provide 24-hour samples daily for SLAMS reporting. During sampling, ambient air passes through an inlet designed to pass only particles smaller than 10 microns in diameter. After exiting the inlet, the sample stream is sent to a mass transducer. Inside the transducer the sample stream passes through a Teflon-coated glass fiber filter. This filter is weighed every two seconds. The difference between the current filter weight and the initial or installed weight gives the total mass of the collected particulate. The mass concentration is computed by dividing the total mass by the flow rate. Data is transmitted by telemetry for entry into the automated central data acquisition system.

(b) **Particulate Matter 2.5 microns in size ($PM_{2.5}$)**

With the exception of continuous samplers, all $PM_{2.5}$ samplers operated by the Division for Air Quality are certified as either FRM or FEM samplers. All manual samplers are operated per the requirements set forth in 40 CFR 50, Appendix L. Samples are collected on 46.2mm PTFE filters over a 24-hour sampling period. Air flow through the filter is to be maintained at 16.7 liters per minute. The flow rate must not vary more than +/-5% for five minutes over a 24-hour sample period at actual ambient temperature and pressure. Samples must be retrieved within 177 hours of the end of the sample run and must be kept cool (4 degrees C or cooler) during transit to meet the thirty-day limit for re-weighing.

The PTFE filters are to be equilibrated before each weighing for a minimum of 24 hours at a controlled atmosphere of 20-23 degrees C mean temperature and 30-40% mean relative humidity. Filters must be used within thirty days of initial weighing. Filters must be re-weighed within thirty days of the end of the sample run and must be kept at 4 degrees C or cooler. The gain in weight in relation to the volume of air sampled is calculated in micrograms per cubic meter (ug/m^3).

Continuous $PM_{2.5}$ samplers provide 24-hour samples daily for AQI reporting. During sampling, ambient air passes through an inlet and very sharp cut cyclone designed to pass only particles smaller than 2.5 microns in diameter. After exiting the inlet, the sample stream is sent to a mass transducer. Inside the transducer the sample stream passes through a Teflon-coated glass fiber filter. This filter is weighed every two seconds. The difference between the current filter weight and the initial or installed weight gives the total mass of the collected particulate. The mass concentration is computed by dividing the total mass by the flow rate.

Another means of measuring $PM_{2.5}$ continuously is through beta ray attenuation. During sampling, ambient air passes through an inlet and very sharp cut cyclone designed to pass only particles smaller than 2.5 microns in diameter. The sample is collected on filter tape as the air passes through the tape. The filter tape is then placed in between a beta source and a scintillation detector causing an attenuation of the beta particle signal.

Data is transmitted by telemetry for entry into the automated central data acquisition system.

(c) **$PM_{2.5}$ Speciation sampling and analysis**

In addition to operating $PM_{2.5}$ samplers that determine only $PM_{2.5}$ mass values, KYDAQ also operates $PM_{2.5}$ speciation samplers that collect samples that are analyzed to determine the chemical makeup of $PM_{2.5}$. Samples are collected on a set of three filters over a 24-hour sampling period. The individual filters are composed of different media in order to collect specific types of toxic pollutants.

After collection, the samples are shipped in ice chests to an EPA contract laboratory for analysis. At the laboratory, the samples are analyzed using optical and electron microscopy, thermal optical analysis, ion chromatography and x-ray fluorescence to determine the presence and level of specific toxic compounds. Sample results are entered in the AQS data system.

(d) **Sulfur Dioxide**

Instruments used to continuously monitor sulfur dioxide levels in the atmosphere employ the UV fluorescence and UV open path methods. The continuous data output from the instrument is transmitted by telemetry for entry into an automated central data system.

Calibration of these instruments is done dynamically using certified gas mixtures containing a known concentration of sulfur dioxide gas. This gas is then diluted in a specially designed apparatus to give varying known concentrations of sulfur dioxide. These known concentrations are supplied to the instruments, which are adjusted so that instrument output corresponds with the specific concentrations. Calibration curves are prepared for each instrument and each data point is automatically compared to this curve before entry into the data acquisition system.

(e) **Carbon Monoxide**

Continuous monitoring for carbon monoxide is performed by use of the non-dispersive infrared correlation method. Data is transmitted by telemetry for entry in an automated central data acquisition system.

Calibration of the instrument is performed periodically by using nitrogen or zero air to establish the zero baseline and NIST or NIST traceable gas mixtures of carbon monoxide in air. The span is checked daily using a certified mixture of compressed gas containing approximately 45 parts per million carbon monoxide.

(f) **Ozone**

Ozone is monitored using the UV photometry and UV open path methods. The continuous data output from the instrument is transmitted by telemetry for entry into an automated central data acquisition system.

Monitors are calibrated routinely using an ozone generator, which is calibrated using the ultra violet photometry reference method. Calibration curves are prepared for each instrument and each data point is automatically compared to this curve before entry into the data acquisition system.

(g) **Nitrogen Dioxide**

The chemiluminescence and UV open path methods are used in monitoring the nitrogen dioxide level in the ambient air. The continuous data output from the instrument is transmitted by telemetry for entry into an automated central data acquisition system.

Calibration of these instruments is done dynamically using NIST certified gas mixtures of nitric oxide. Through the use of dilution apparatus, varying concentrations are produced and supplied to the monitors, thus producing a specific calibration curve for each instrument. Each data point is automatically compared to this curve before entry into the data acquisition system.

(h) **Lead**

Lead concentrations are determined from the analysis of suspended particulates collected by high volume particulate samplers. Particulate samples are ashed to remove organic matter and acid extracted to dissolve the metals. The lead content is determined by the atomic absorption spectroscopy method or an approved Federal Equivalent Method.

(i) **Mercury**

Cold vapor atomic fluorescence spectrometry is used to determine elemental gaseous mercury in ambient air at sub-ng/m^3 levels. The analyzer uses a dual, ultra pure gold absurbent cartridge design that allows alternating desorption and sampling. The dual cartridge design results in continuous mercury sampling of the air stream. The continuous data output from the instrument is transmitted by telemetry for entry into an automated central data acquisition system.

(j) **Air Toxics**

Air toxics pollutants are determined in three categories: metals, volatile organic compounds (VOC), and carbonyls.

Metal samples are collected on 46.2 mm PTFE filter over a 24-hour period similar to the PM_{10} monitoring method. The filter is weighed before and after the sample run. The gain in weight in relation to the volume of air sampled is used to calculate the concentration in micrograms per cubic meter (ug/m^3). The PTFE filter is to be equilibrated before each weighing for a minimum of 24 hours at a 20-23 degrees C mean temperature and a 30-40% mean relative humidity. The filter is then delivered to the Division for Environmental Program Support for inductively coupled plasma/mass spectrometer analysis to determine the concentration of metals in ug/m^3.

VOC samples are collected in a vacuum canister. Ambient air is pulled into the canister over a 24-hour sampling period. The sample is shipped to the Division for Environmental Program Support for gas chromatography/mass spectrometer analysis. VOC concentrations determined in the sample are reported in ug/m^3.

Carbonyl samples are collected on a DPNH cartridge. An ambient air stream flows through the cartridge at a (1) liter per minute flow rate for a 24-hour sampling period. The cartridge is packed on ice and shipped to the Division for Environmental Program Support for high-pressure liquid chromatography analysis. Carbonyl concentrations determined in the sample are reported in ug/m^3.

(k) **Wet Deposition**

Acid precipitation monitoring stations operate on a weekly sampling schedule. Cumulative precipitation events occurring during a seven-day period are collected in one container to represent a one-week sample. An Aerochem precipitation monitor and NCON monitors are used to collect the wet deposition samples. The principle of operation of the samplers is based on the use of a moisture sensor that activates an electrically driven movable container lid covering the "wet" container during dry periods and then is moved to uncover the "wet" container when precipitation occurs. The opening and closing of the lid for each precipitation event is indicated on a data logger providing the time and date of each event. At the end of each weekly sampling period, the sample bag/bottle in the "wet" container is removed and a new sample bag/bottle is installed. The sample is then analyzed at the Division for Environmental Program Supports' laboratory.

7. Quality Assurance Status

The Division for Air Quality has an extensive quality assurance program to ensure that all air monitoring data collected is accurate and precise. Staff members audit air monitors on a scheduled basis, including those operated by the Louisville Metro Air Pollution Control District, to ensure that each instrument is calibrated and operating properly. Data validation is performed monthly by verifying the data reported by each instrument is recorded accurately in the computerized database.

8. Area Representativeness

Each station in the monitoring network must be described in terms of the physical dimensions of the air parcel nearest the monitoring station throughout which actual pollutant concentrations are reasonably similar. Area dimensions or scales of representativeness used in the network description are:

(a) Microscale - defines the concentration in air volumes associated with area dimensions ranging from several meters up to about 100 meters.

(b) Middle scale - defines the concentration typical of areas up to several city blocks in size with dimensions ranging from about 100 meters to 0.5 kilometers.

(c) Neighborhood scale - defines the concentrations within an extended area of a city that has relatively uniform land use with dimensions in the 0.5 to 4.0 kilometers.

(d) Urban scale - defines an overall citywide condition with dimensions on the order of 4 to 50 kilometers.

(e) Regional Scale - defines air quality levels over areas having dimensions of 50 to hundreds of kilometers.

Closely associated with the area around the monitoring station where pollutant concentrations are reasonably similar are the basic monitoring exposures of the station. There are four basic exposures included in this description:

(a) To determine the highest concentrations expected to occur in the area covered by the network.

(b) To determine representative concentrations in areas of high population density.

(c) To determine the impact on ambient pollution levels of significant sources or source categories.

(d) To determine general background concentration levels.

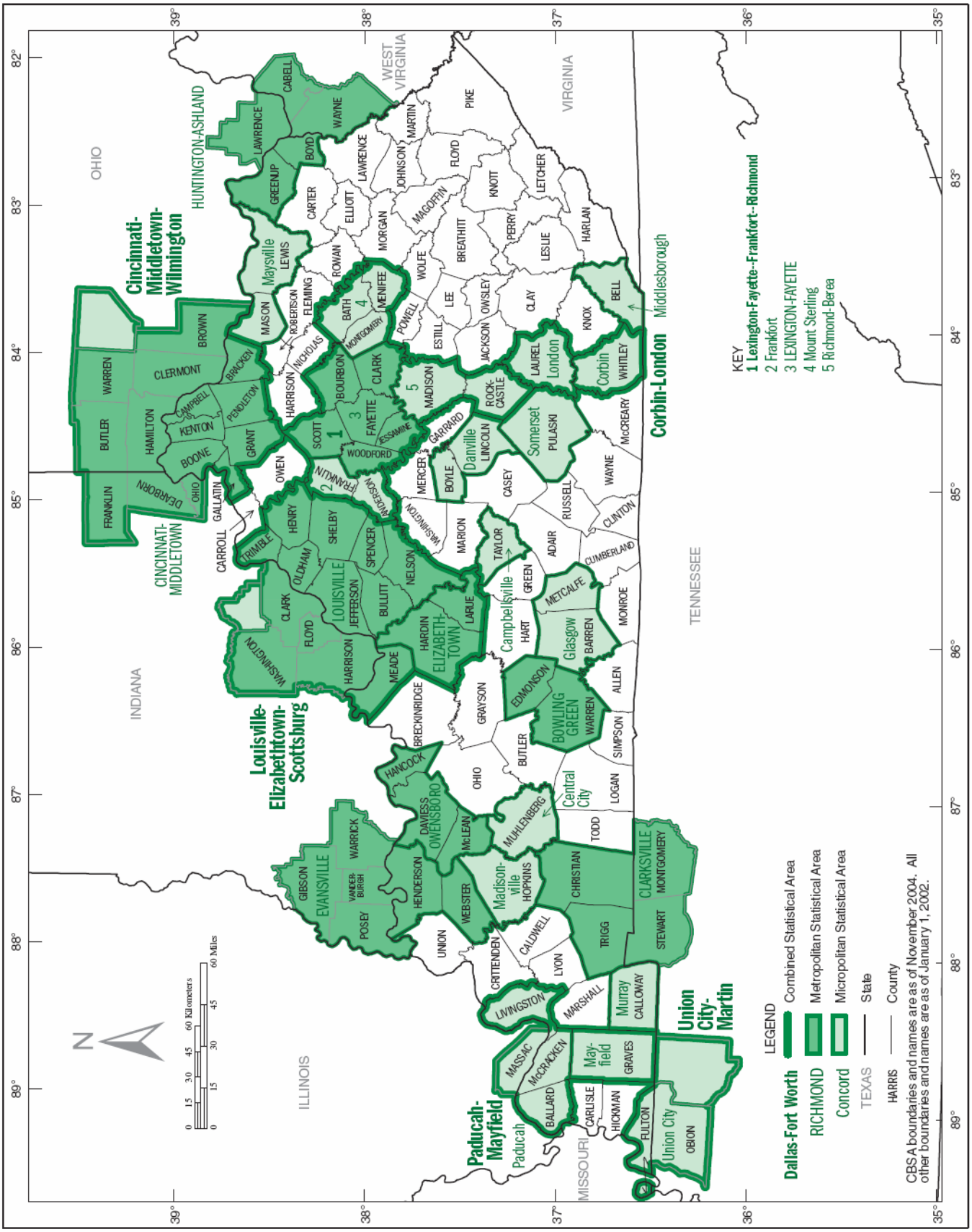
The design intent in siting stations is to correctly match the area dimensions represented by the sample of monitored air with the area dimensions most appropriate for the monitoring objective of the station. The following relationship of the four basic objectives and the area of representativeness are appropriate when siting monitoring stations:

Monitoring Exposures	**Siting Area Scale**
Highest concentration	Micro, Middle, Neighborhood
Population	Neighborhood, Urban
Source impact	Micro, Middle, Neighborhood
General/background	Neighborhood, Regional

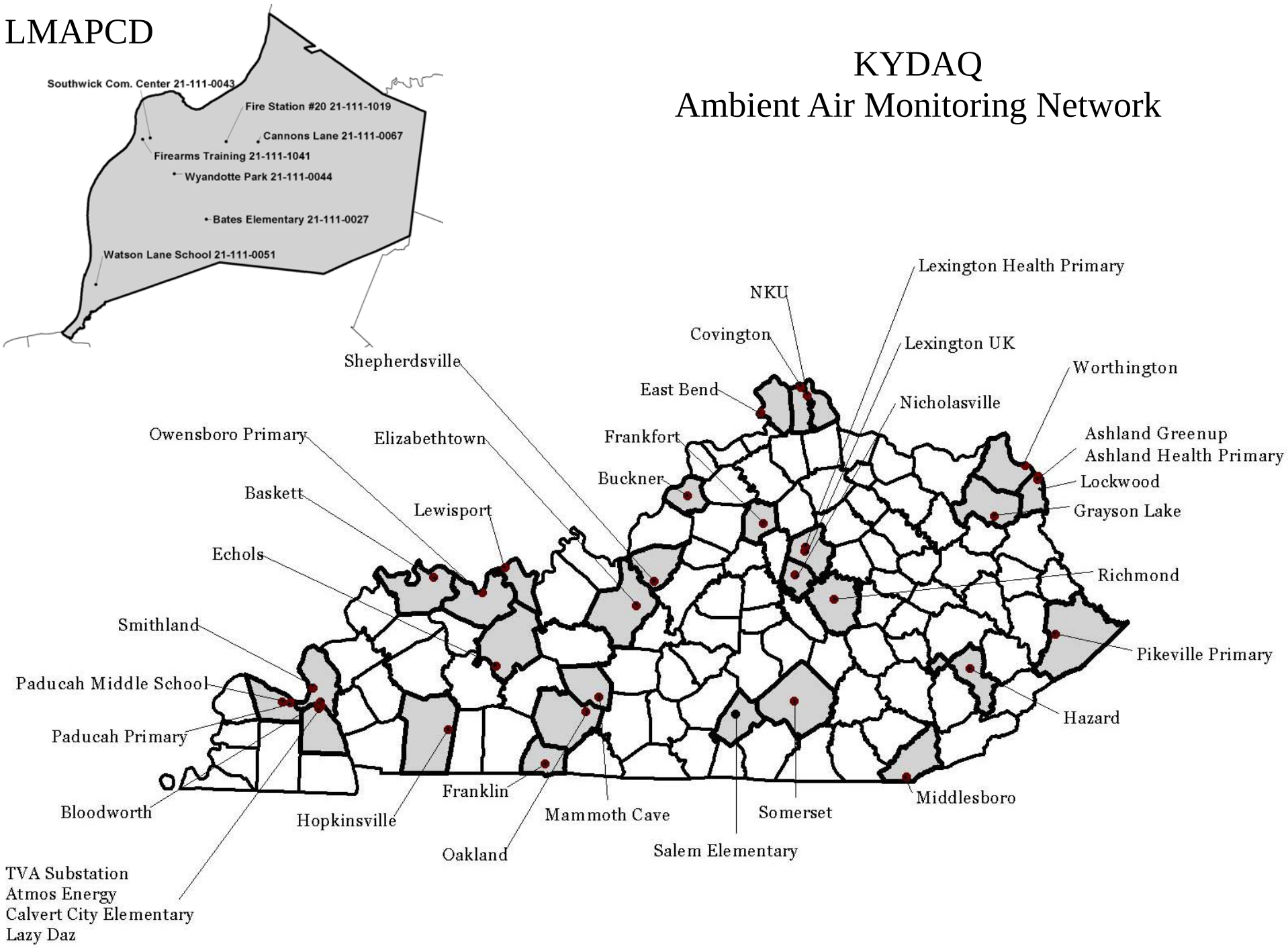
Data Processing and Reporting

All ambient air quality data are stored in a centralized server located at the 14th floor of the Capital Plaza Tower, the Energy and Environment Cabinet (EEC) headquarters in Frankfort, Kentucky. The server is backed up on tape nightly, weekly, and monthly. The backup tape of the server is stored off site of the EEC headquarters and is cycled through use on a monthly schedule. After each month of data has passed all quality assurance checks, the data is transmitted via telemetry to the U.S. EPA's national data storage system known as AQS. Statistical data summaries are generated from this database and compiled to produce the Ambient Air Quality Annual Report. This report may be accessed at the KYDAQ website:http://www.air.ky.gov. The report is located under **Public Information**.

KENTUCKY - Core Based Statistical Areas and Counties



U.S. DEPARTMENT OF COMMERCE Economics and Statistics Administration U.S. Census Bureau


LMAPCD
Southwick Com. Center 21-111-0043
Fire Station #20 21-111-1019
Cannons Lane 21-111-0067
Firearms Training 21-111-1041
Wyandotte Park 21-111-0044
Bates Elementary 21-111-0027
Watson Lane School 21-111-0051
KYDAQ
Ambient Air Monitoring Network
Lexington Health Primary
NKU
Covington
Lexington UK
Worthington
Shepherdsville
East Bend
Nicholasville
Owensboro Primary
Elizabethtown
Frankfort
Ashland Greenup
Ashland Health Primary
Buckner
Lockwood
Baskett
Lewisport
Grayson Lake
Echols
Richmond
Smithland
Pikeville Primary
Paducah Middle School
Hazard
Paducah Primary
Franklin
Middlesboro
Bloodworth
Hopkinsville
Mammoth Cave
Somerset
Oakland
Salem Elementary
TVA Substation
Atmos Energy
Calvert City Elementary
Lazy Daz

AIR MONITORING STATIONS SUMMARY

Metropolitan Statistical Area	Number of Sites	$PM_{2.5}$	PM_{10}	PM_{coarse}	SO_2	NO_2	NO_y	CO	O_3	Pb/ Metals	Hg	Wet Dep	VOC	Carbonyl	Speciation	MET
Bowling Green, KY	2	4 CT	0	0	1	1	0	1	2	0	1	0	0	0	0	1
Cincinnati-Middletown, OH-KY-IN	3	4 T	0	0	1	1	0	0	3	0	1	1	1	1	1	2
Clarksville, TN-KY	1	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Elizabethtown, KY	1	3 T	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Evansville, IN-KY	1	2 T	1	0	1	0	0	0	1	0	0	0	0	0	0	0
Huntington-Ashland, WV-KY-OH	3	2 T	2 C**	0	2	1	0	0	2	3 C	0	0	1	1	1	1
Lexington-Fayette, KY	3	3 T	1 **	0	2	1	0	0	2	1	1	1	1	1	1	1
Louisville-Jefferson County, KY-IN	10	12 CT	4 C**	1	3	1	1	2	5	0	0	0	0	0	1	3
Owensboro, KY	2	2 CT	0	0	1	1	0	0	2	0	0	0	0	0	0	1
Micorpolitan Statistical Area																
Paducah, KY-IL	4	2 T	1	0	2	1	0	0	2	0	1	1	1	0	0	1
Somerset, KY	1	1 T	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Middlesborough, KY	1	1	0	0	0	0	0	0	1	0	0	0	0	0	0	1
Richmond-Berea, KY	1	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Frankfort, KY	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Not in a MSA																
Carter County	1	1	2 C	0	0	0	0	0	1	2 C	1	2	2	2	1	1
Marshall County	4	0	1	0	0	0	0	0	0	1	0	0	5	0	0	1
Ohio County	1	2 T	1 **	0	0	0	0	0	0	1	1	1	0	0	0	1
Perry County	1	1 T	0	0	0	0	0	0	1	0	0	0	0	0	0	1
Pike County	1	3 T	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Russell County	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Simpson County	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	1
TOTALS	43	46	13	1	13	7	1	3	27	10	6	6	11	5	5	16

C=Collocated monitors; D=Duplicate monitors; T= Continuous PM2.5 monitors or continuous PM10 monitors; **=Multiple analysis: PM10 Teflon filters used for PM10 monitoring, Metals monitoring and PMcoarse)

SUMMARY OF NETWORK CHANGES 2009

MSA Summary:

Cincinnati-Middletown, OH-KY-IN - NKU (21-037-3002) add $PM_{2.5}$ beta attenuation monitor

Elizabethtown, KY MSA – Elizabethtown (21-093-0006) add $PM_{2.5}$ collocated sampler moved from the Evansville, IN-KY MSA.

Evansville, IN-KY MSA – Baskett (21-101-0014) remove the collocated $PM_{2.5}$ sampler and install a PM_{10} sampler.

Huntington-Ashland, WV-KY-OH MSA – Lockwood (21-019-0016) establish a site and add a source impact lead sampler.

Not in a MSA Summary:

Grayson, KY – Grayson Lake (21-043-0500) increase sampling frequency for the duplicate PM_{10} from every twelfth day to every sixth day.

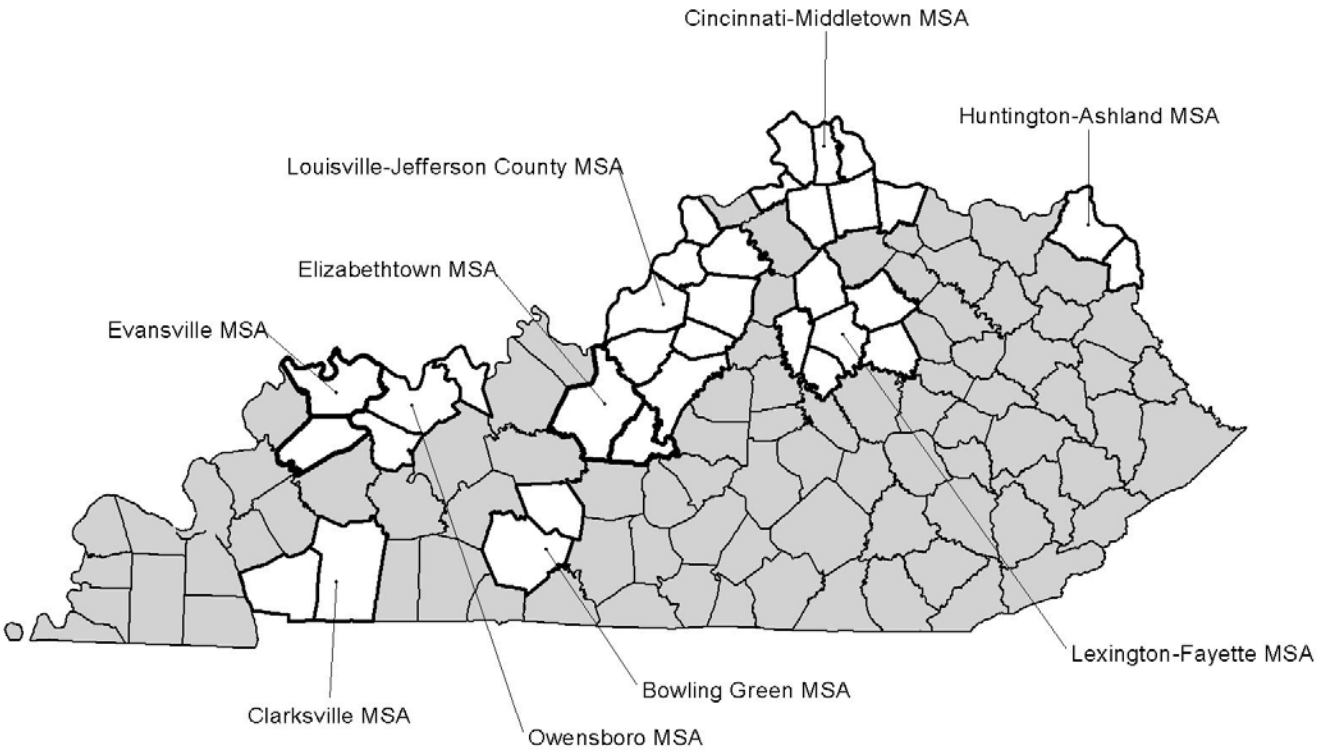
Pikeville, KY – Pikeville (21-195-0002) increase sampling frequency for the duplicate $PM_{2.5}$ from every twelfth day to every sixth day.

Richmond, KY – Richmond (21-151-0003) and add source impact lead sampler and collocated source impact lead sampler.

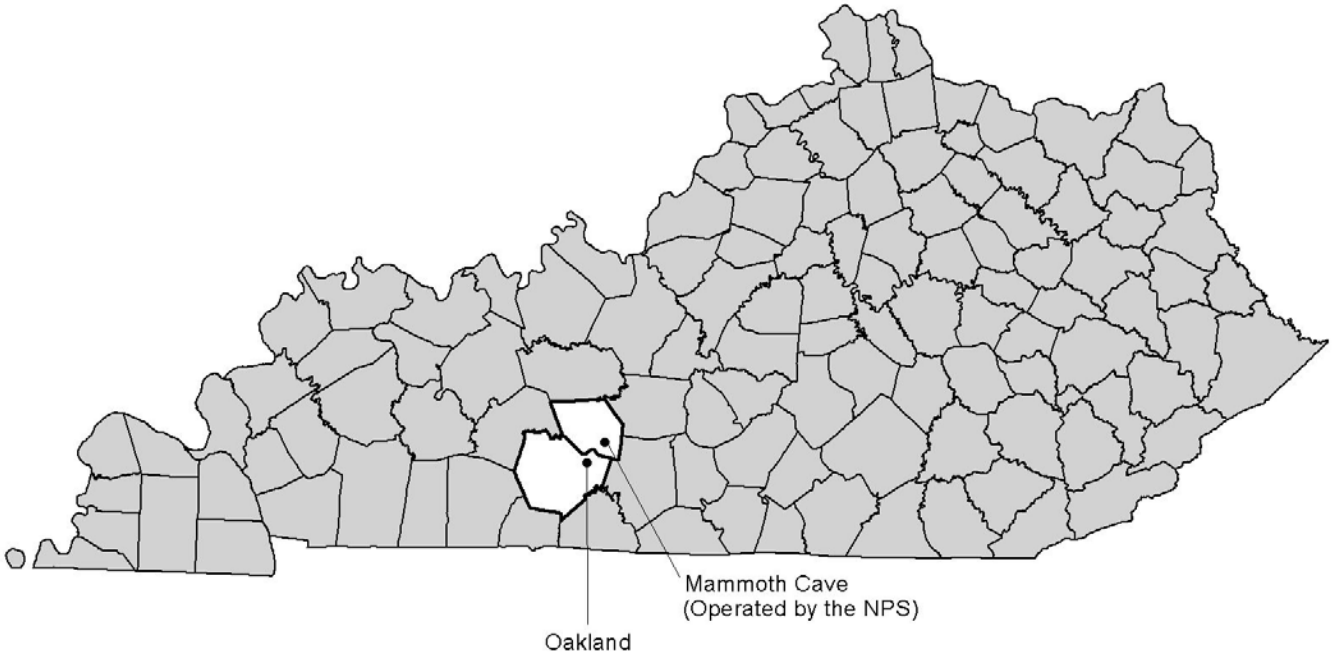
Russell Springs, KY - Salem Elementary (TBD) add source impact lead sampler.

Somerset, KY - Somerset (21-199-0003) add $PM_{2.5}$ beta attenuation monitor

Metropolitan Statistical Areas



Bowling Green, KY



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-061-0501 (NPS)	Alfred Cook Road Mammoth Cave (Edmonson)	X(t)		X	X	X	X		X	X				X
21-227-0008	Oakland School Oakland (Warren)	X(ctI)					X(sI)							
	TOTAL	4	0	1	1	1	2	0	1	1	0	0	0	1

(c) Collocated Monitor
(I) Air Quality Index Monitor
(s) Special Purpose Monitor
(t) Continuous PM Monitor

(Rev.5/23/08)

CSA/MSA: Bowling Green, KY MSA
401 KAR 50:020 Air Quality Region: South Central Kentucky Intrastate (105)
Site Name: Oakland Primary
AQS Site ID: 21-227-0008
Location: Oakland Elementary School, Oakland, KY 42159
County: Warren
GPS Coordinates: 37.036667, -86.250556
Date Established: January 1, 2000
Inspection Date: December 4, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Oakland Elementary School in Oakland, Kentucky. The sample inlets are 200 feet from the nearest road. The most recent site inspection was conducted on December 4, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

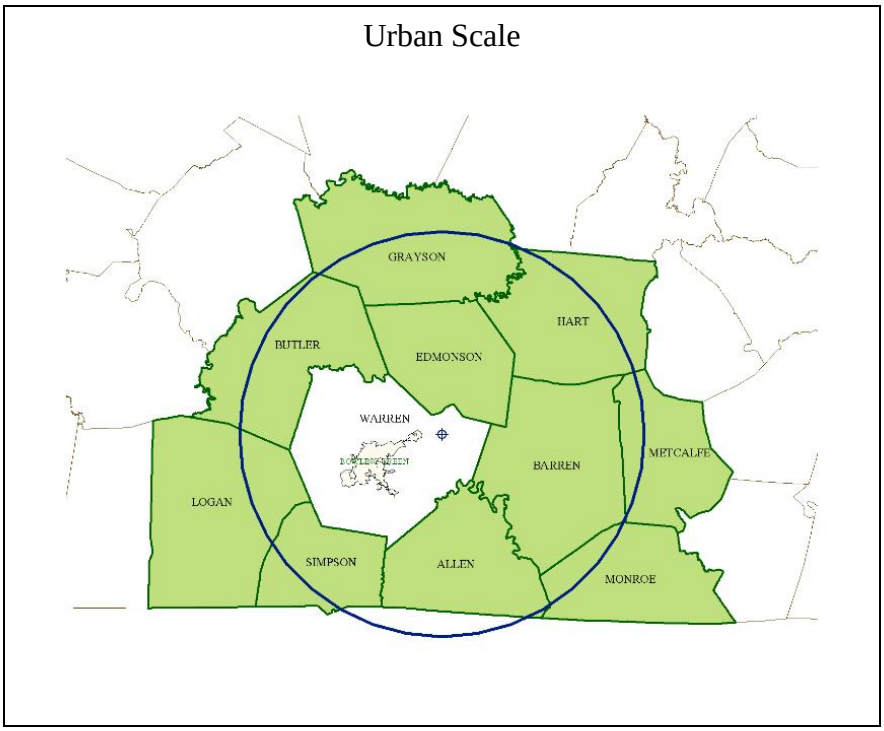
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide levels of ozone and particulate matter for daily index reporting.

Monitors:

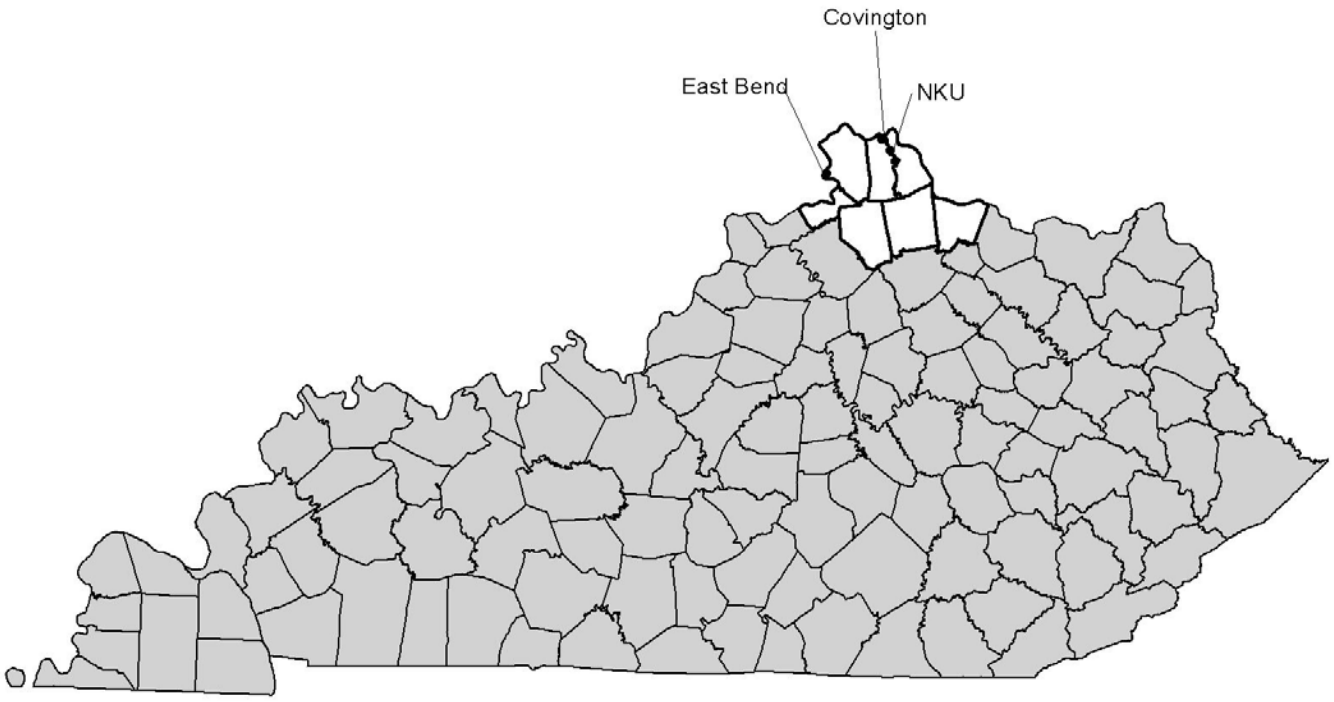
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4	SPM AQI	UV photometry	Continuously March 1 – October 31
$PM_{2.5}$ TEOM	5	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously
FEM $PM_{2.5}$	5	SLAMS	Gravimetric	24-hours every third day
- Collocated FRM $PM_{2.5}$	5	SLAMS	Gravimetric	24-hours every third day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on an urban scale for particulates. This site also represents maximum concentration on and urban scale for ozone.



Cincinnati-Middletown, OH-KY-IN



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-015-0003	KY 338 & Lower River Road East Bend (Boone)						X							X
21-037-3002	524A John's Hill Road Highland Heights(Campbell)	X(It)		X(I)	X		X(Ie)		X	HG				
21-117-0007	1401 Dixie Highway Covington (Kenton)	X(tIe)					X(I)				X	X	X	X
	TOTAL	4	0	1	1	0	3	0	1	1	1	1	1	2

(e) Emergency Episode Monitor

(I) Air Quality Index Monitor

(s) Special Purpose

(t) Continuous PM Monitor

(Rev.6/30/09

CSA/MSA: Cincinnati-Middletown-Wilmington, OH-KY-IN CSA/Cincinnati-Middletown, OH-KY-IN MSA
401 KAR 50:020 Air Quality Region: Metropolitan Cincinnati (Ohio) Interstate (079)
Site Name: East Bend
AQS Site ID: 21-015-0003
Location: KY 338 and Lower River Road, East Bend, KY 41005
County: Boone
GPS Coordinates: 38.918056, -84.852778
Date Established: July 1, 1977
Inspection Date: November 4, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located at the intersection of KY 338 and Lower River Road in East Bend, Kentucky. The sample inlets are 50 feet from the nearest road. The most recent site inspection was conducted on November 4, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

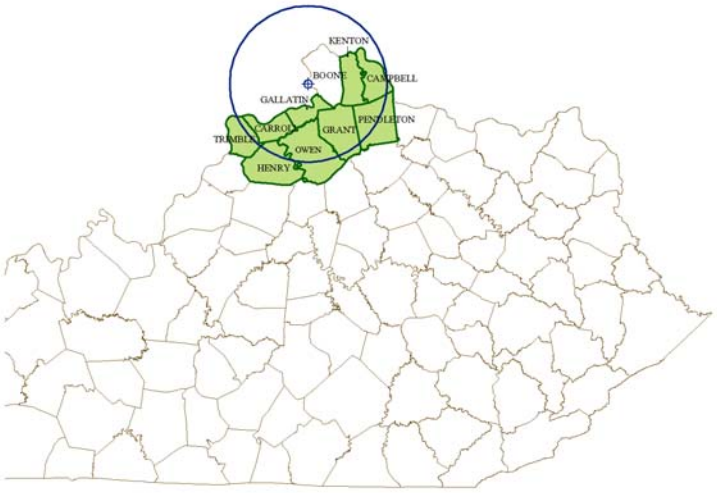
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.3	SLAMS AQI	UV photometry	Continuously March 1 – October 31
Meteorological	5.5	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents background levels on an urban scale for ozone.

Urban Scale



CSA/MSA: Cincinnati-Middletown-Wilmington, OH-KY-IN CSA/Cincinnati-Middletown, OH-KY-IN MSA
401 KAR 50:020 Air Quality Region: Metropolitan Cincinnati (Ohio) Interstate (079)
Site Name: Covington
AQS Site ID: 21-117-0007
Location: University College, 1401 Dixie Hwy, Covington, KY 41011
County: Kenton
GPS Coordinates: 39.072500, -84.525000
Date Established: August 22, 1975
Inspection Date: November 4, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the University College in Covington, Kentucky. The sample inlets are 40 feet from the nearest road. The most recent site inspection was conducted on November 4, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to provide ozone, particulate and sulfur dioxide levels for daily index reporting; and to detect elevated pollutant levels for activation of emergency control procedures for particulates.

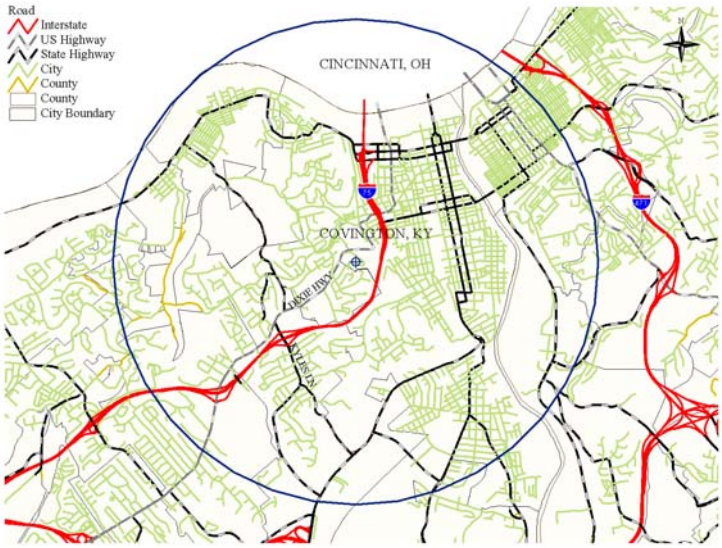
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.6	SLAMS AQI	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.6	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Speciation	4.5	SLAMS	Thermal optical, ion chromatography, and X-ray fluorescence	24-hours every sixth day
$PM_{2.5}$ TEOM	4.5	SPM AQI EPISODE	Tapered element oscillating microbalance, gravimetric	Continuously
Volatile Organics Compound	4.3	SPM	EPA method TO-15	24-hours every sixth day
Carbonyls	4.3	SPM	EPA method TO-11A	24-hours every sixth day
Meteorological	7.6	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for ozone and particulates.

Neighborhood Scale



CSA/MSA: Cincinnati-Middletown-Wilmington, OH-KY-IN CSA/Cincinnati-Middletown, OH-KY-IN MSA
401 KAR 50:020 Air Quality Region: Metropolitan Cincinnati (Ohio) Interstate (079)
Site Name: Northern Kentucky University "NKU"
AQS Site ID: 21-037-3002
Location: 524A John's Hill Road, Highland Heights, KY 41076
County: Campbell
GPS Coordinates: 39.02181, -84.47445
Date Established: August 1, 2007
Inspection Date: November 4, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on farmland owned by the Northern Kentucky University in Highland Heights, Kentucky. The sample inlets are 72 feet from the nearest road, which is a dirt service drive for a radio tower. The most recent site inspection was conducted on November 4, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to provide ozone, particulate and sulfur dioxide levels for daily index reporting; and to detect elevated pollutant levels for activation of emergency control procedures for ozone.

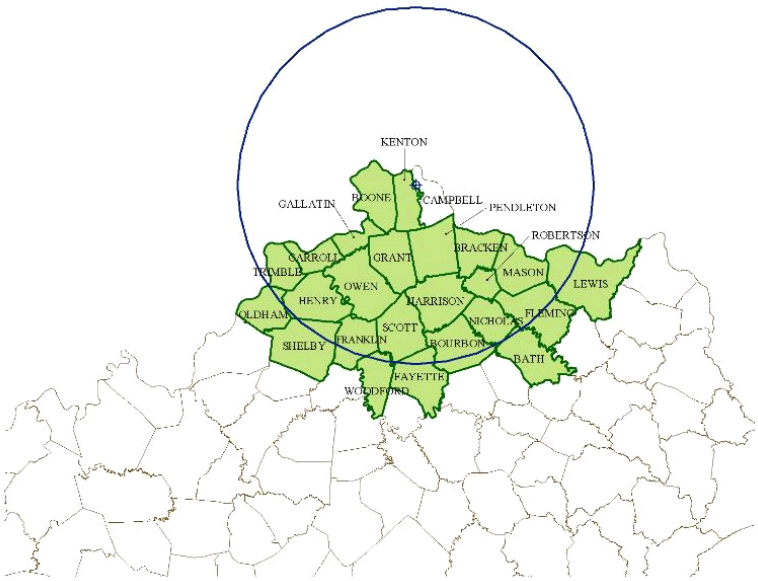
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide	3.8	SLAMS	Chemiluminescence	Continuously
AEM Ozone	3.8	SLAMS AQI EPISODE	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.6	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ BAM	4	SPM AQI	Beta Attenuation Mass Monitor	Continuously
AEM Sulfur Dioxide	3.9	SLAMS AQI	UV fluorescence	Continuously
Mercury - ambient	3.7	SPM	Cold vapour atomic fluorescence spectrometry	Continuously
Mercury – Wet Deposition	1.5	SPM	Wet deposition collected, analysis of sample by the Environmental Services laboratory	Weekly
Meteorological	1.5	Other	Rain gauge	Continuously

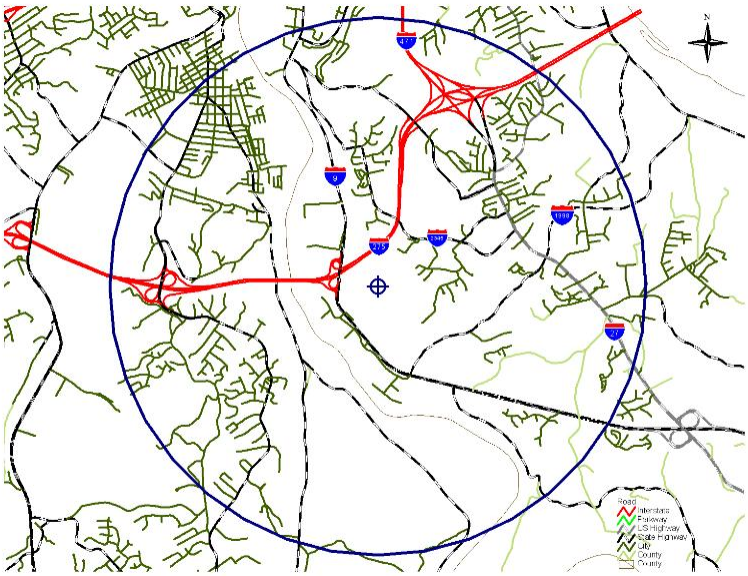
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure for nitrogen dioxide, ozone, sulfur dioxide and mercury on an urban scale. This site also represents population exposure on a neighborhood scale for particulate matter.

Urban Scale



Neighborhood Scale



Clarksville, TN-KY

AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-047-0006	10800 Pilot Rock Road Hopkinsville (Christian)	X					X							
	TOTAL	1	0	0	0	0	1	0	0	0	0	0	0	0

(Rev.5/23/08)

CSA/MSA: Clarksville, TN- KY MSA
401 KAR 50:020 Air Quality Region: Paducah - Cairo Interstate (072)
Site Name: Hopkinsville
AQS Site ID: 21-047-0006
Location: 10800 Pilot Rock Road, Hopkinsville, KY 42240
County: Christian
GPS Coordinates: 36.911667, -87.323611
Date Established: January 1, 1999
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is on a platform in a field and a stationary equipment shelter adjacent to a residence located at 10800 Pilot Rock Road in Hopkinsville, Kentucky. The sample inlet is 300 feet from the nearest road. The most recent site inspection was conducted on December 17, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

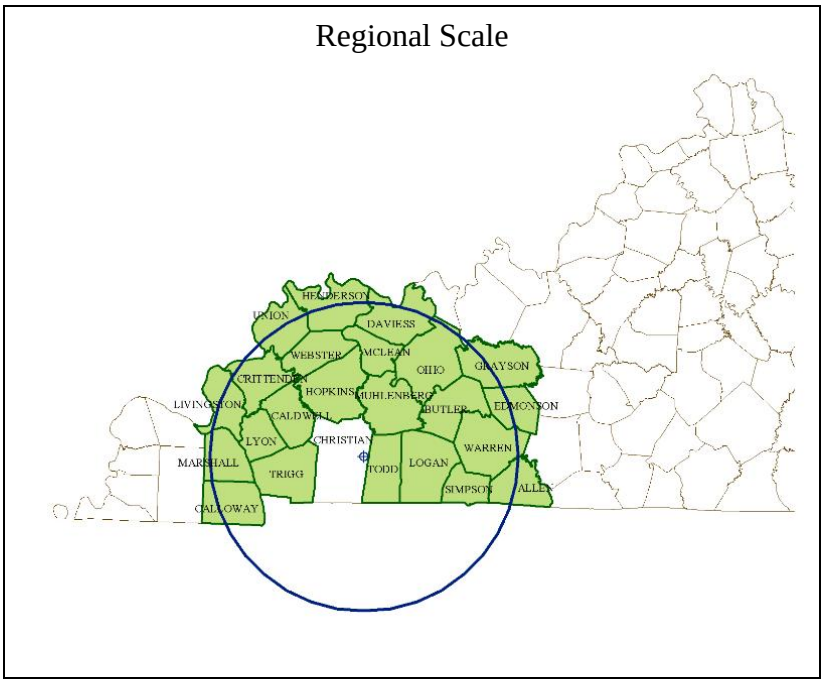
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality standards and to determine levels of interstate transport of fine particulate matter.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.8	SLAMS AQI	UV photometry	Continuously March 1 – October 31
FEM $PM_{2.5}$	3	SLAMS	Gravimetric	24-hours every third day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a regional scale.



Elizabethtown, KY

AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-093-0006	801 N Miles St, Am Legion Park Elizabethtown (Hardin)	X(ct)					X(s)							
	TOTAL	3	0	0	0	0	1	0	0	0	0	0	0	0

(c) Continuous Monitor

(s) Special Purpose Monitor

(t) Continuous PM Monitor

(Rev.5/20/09)

CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Elizabethtown, KY MSA
401 KAR 50:020 Air Quality Region: North Central Kentucky Intrastate (104)
Site Name: Elizabethtown
AQS Site ID: 21-093-0006
Location: American Legion Park, 801 North Miles Street, Elizabethtown, KY 42701
County: Hardin
GPS Coordinates: 37.706389, -85.851667
Date Established: February 24, 2000
Inspection Date: December 17, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located near the tennis courts on the grounds of the American Legion Park in Elizabethtown, Kentucky. The sample inlets are 800 feet from the nearest road. The most recent site inspection was conducted on December 17, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide ozone and particulate levels for daily index reporting.

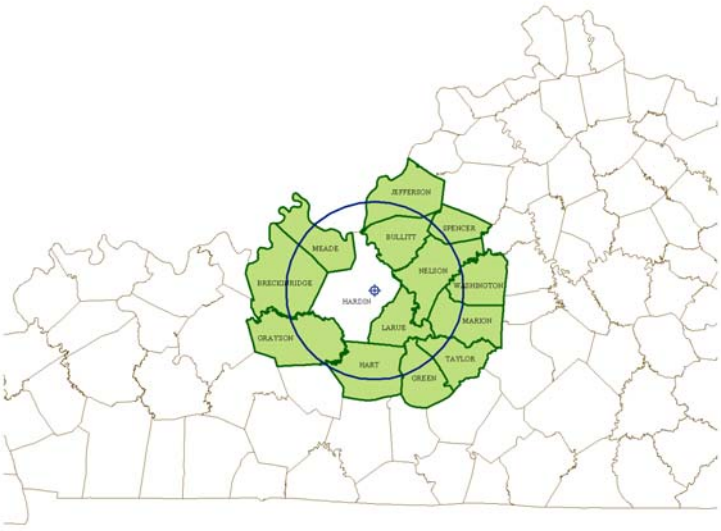
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.3	SPM AQI	UV photometry	Continuously March 1 – October 31
FEM $PM_{2.5}$	4.5	SLAMS	Gravimetric	24-hours every third day
- Collocated FEM $PM_{2.5}$	4.5	SLAMS	Gravimetric	24-hours every sixth day
$PM_{2.5}$ TEOM	4.2	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

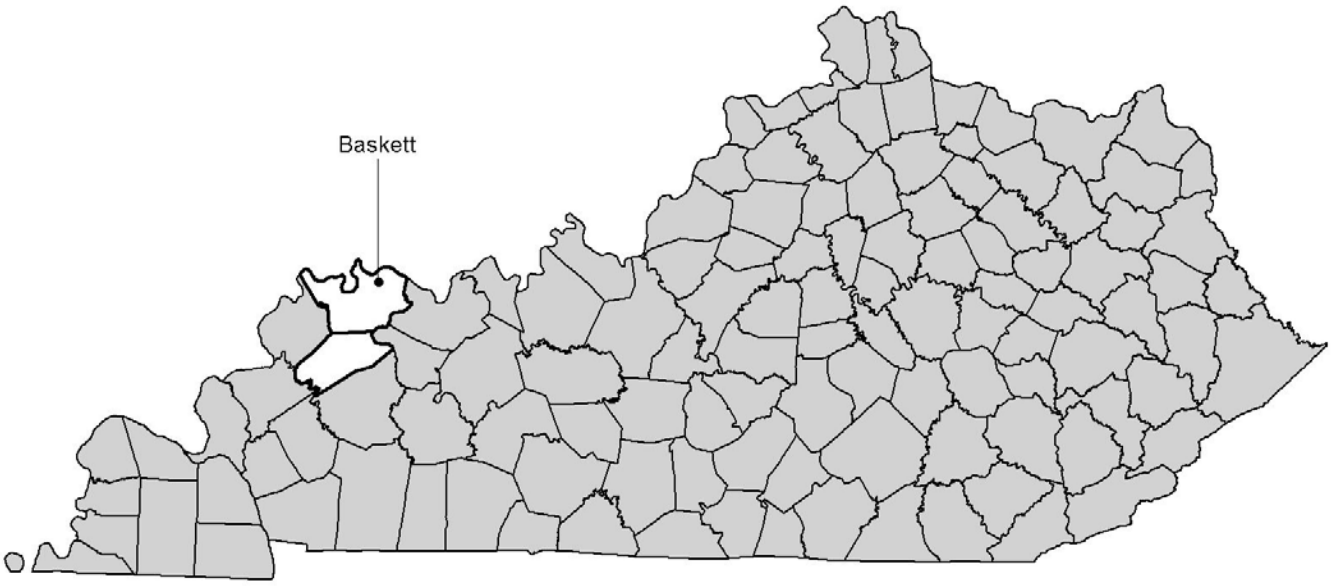
Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates and population exposure on an urban scale for ozone.

Ozone Urban Scale



Particulates Neighborhood Scale

Evansville, IN-KY



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-101-0014	Baskett Fire Department Baskett (Henderson)	X(t)	X	X			X(s)							
	TOTAL	2	1	1	0	0	1	0	0	0	0	0	0	0

(s) Special Purpose Monitor

(t) Continuous PM Monitor

(Rev.5/20/09)

CSA/MSA: Evansville, IN-KY MSA
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Baskett
AQS Site ID: 21-101-0014
Location: Baskett Fire Department, Baskett, KY 42402
County: Henderson
GPS Coordinates: 37.871389, -87.463333
Date Established: February 27, 1992
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Baskett Fire Department in Baskett, Kentucky. The sample inlets are 25 feet from the nearest road. The most recent site inspection was conducted on December 18, 2008 Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide ozone, particulate and sulfur dioxide levels for daily index reporting.

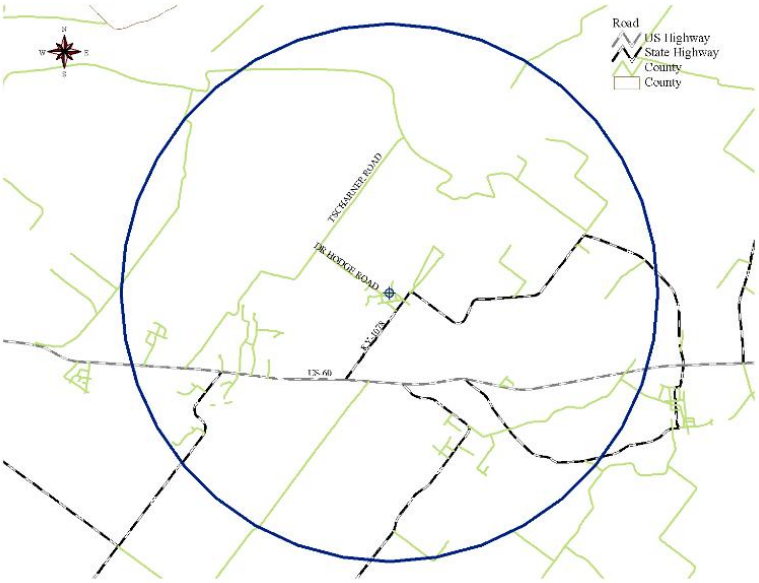
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.3	SPM AQI	UV photometry	Continuously March 1 – October 31
FEM $PM_{2.5}$	4.5	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ TEOM	4.5	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously
FRM PM_{10}	4.5	SLAMS	Gravimetric	24-hours every sixth day
AEM Sulfur Dioxide	4	SLAMS AQI	UV fluorescence	Continuously

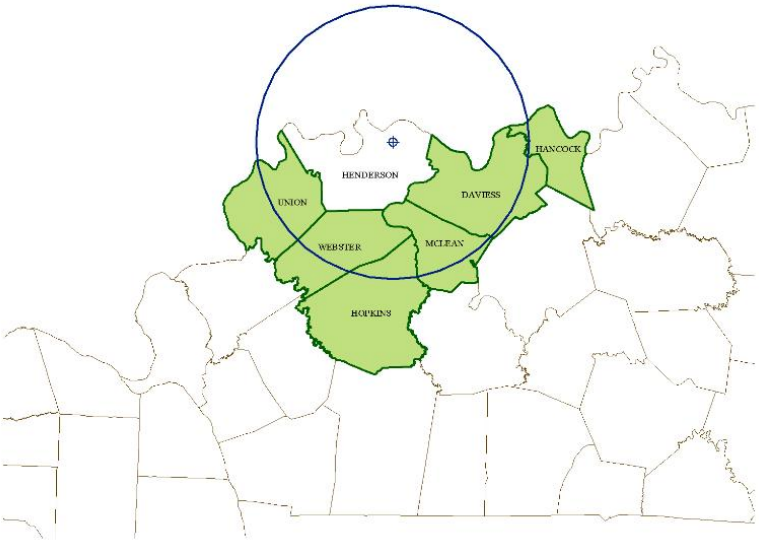
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentration on an urban scale for ozone. This site also represents population exposure on a neighborhood scale for particulates and sulfur dioxide.

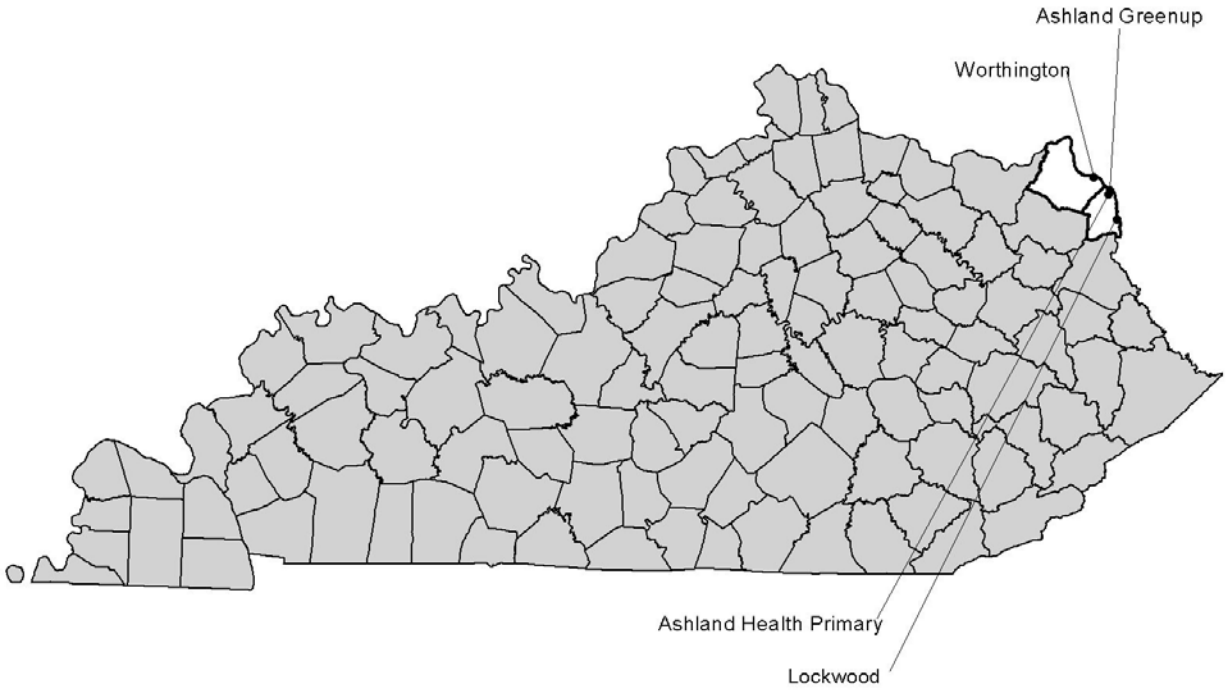
Neighborhood Scale



Ozone Urban Scale



Huntington-Ashland, WV-KY-OH



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Pb/ Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-019-0002	21st & Greenup Ashland (Boyd)		X(c)					X(c)						
21-019-0016	18138 Cherry Wood Catlettsburg (Boyd)							X						
21-019-0017	2924 Holt St, FIVCO Health Dept Ashland (Boyd)	X(It)		X(eI)	X(e)		X(eI)				X(s)	X(s)	X(s)	X
21-089-0007	Water Tower, Scott & Center Sts. Worthington (Greenup)			X(s)			X							
	TOTAL	2	2	2	1	0	2	3	0	0	1	1	1	1

(c) Collocated Monitor
(e) Emergency Episode Monitor
(I) Air Quality Index Monitor
(s) Special Purpose Monitor
(t) Continuous PM Monitor

(Rev.5/20/09)

CSA/MSA: Huntington-Ashland, WV-KY-OH MSA
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Ashland - Greenup
AQS Site ID: 21-019-0002
Location: 122 22nd Street, Ashland, KY 41101
County: Boyd
GPS Coordinates: 38.478611, -82.631944
Date Established: April 2, 1978
Inspection Date: October 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is located on the west end of the roof of the Ashland Valvoline Oil complex building in Ashland, Kentucky. The building is one story tall. The sample inlets are 100 feet from the nearest road. The most recent site inspection was conducted on October 24, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to measure concentrations of a sub-group of air toxics.

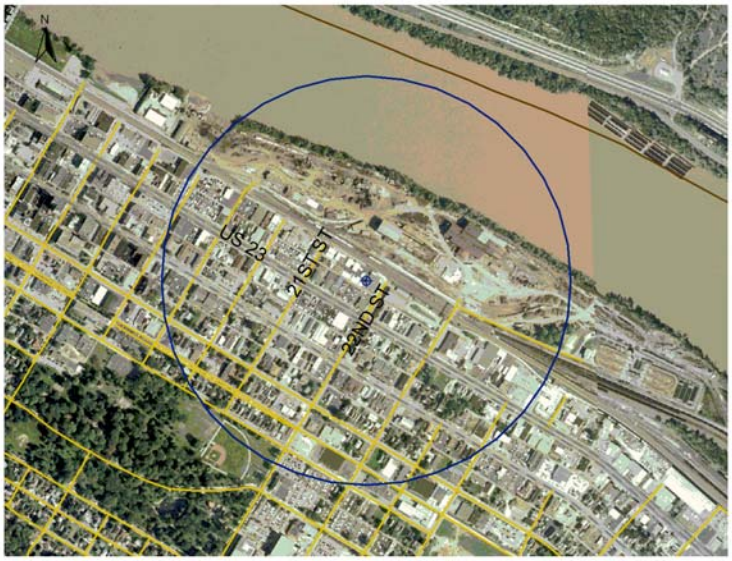
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM PM_{10}	6.6	SLAMS	Gravimetric	24-hours every sixth day
- Collocated FRM PM_{10}	6.6	SPM	Gravimetric	24-hours every sixth day
- Metals PM_{10}		SPM	Determined from the PM_{10} sample using EPA method IO 3.4	Same as PM_{10}

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

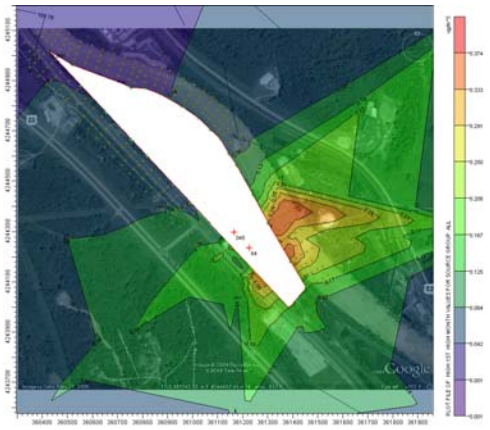
Area Representativeness:
The site represents maximum concentrations on a middle scale for particulates. This site also represents population exposure on a neighborhood scale for air toxics.

Particulate Middle Scale



Air Toxics Neighborhood Scale

CSA/MSA: Huntington-Ashland, WV-KY-OH MSA
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Lockwood
AQS Site ID: 21-019-0016
Location: Catlettsburg, KY
County: Boyd
GPS Coordinates: To be determined
Date Established: January 1, 2010
Inspection Date: Not Applicable
Inspection By:
Site Approval Status:



Calgon Carbon, located in Catlettsburg, Kentucky, was identified as a lead source emitting over 6 tons per year of actual reported emissions in 2007. In accordance with 40 CFR Part 58 Appendix D, a lead source monitoring site will be located in the Lockwood Estates off U.S. 23 in Catlettsburg, Kentucky. The location of this source-oriented lead monitor was determined through the use of AERMOD modeling analysis. The model indicated that majority of the source impact would be in West Virginia. However, the model indicated that Lockwood Estates was within the deposition boundary.

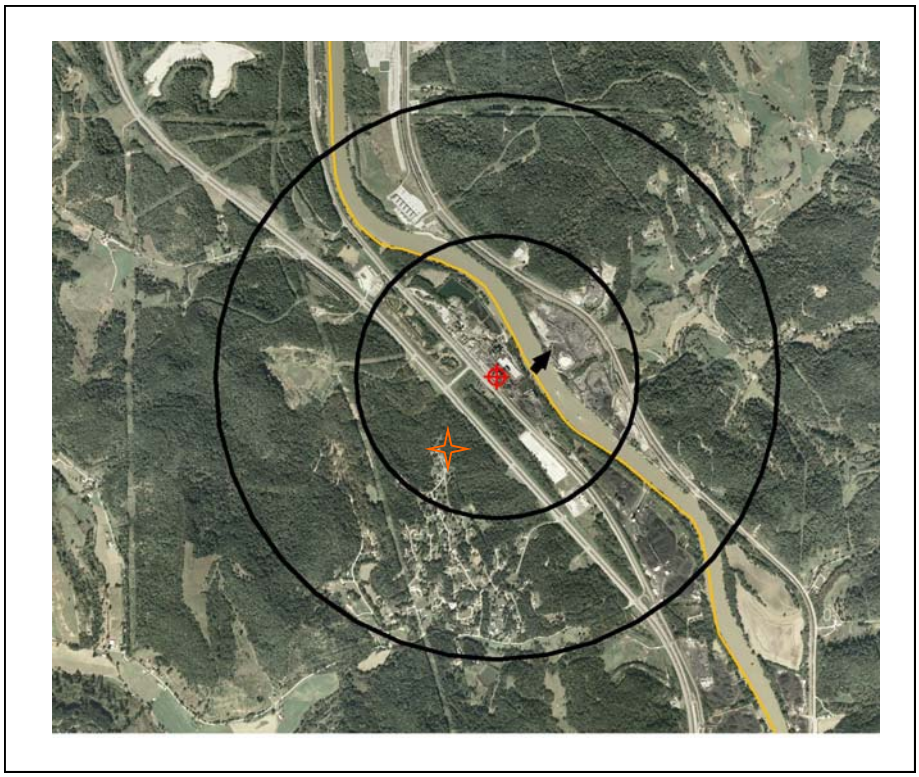
Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM Lead		SLAMS	Gravimetric	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures will be implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents maximum concentrations, from a source, on a middle scale for lead.



CSA/MSA: Huntington-Ashland, WV-KY-OH MSA
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Ashland Primary (FIVCO)
AQS Site ID: 21-019-0017
Location: FIVCO Health Department, 2924 Holt Street, Ashland, KY 41101
County: Boyd
GPS Coordinates: 38.459167, -82.640556
Date Established: January 1, 1999
Inspection Date: October 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the health department building in Ashland, Kentucky. The sample inlets are 240 feet from the nearest road. The most recent site inspection was conducted on October 24, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for nitrogen dioxide, ozone and sulfur dioxide; and to provide pollutant levels for daily air quality index reporting.

Monitors:

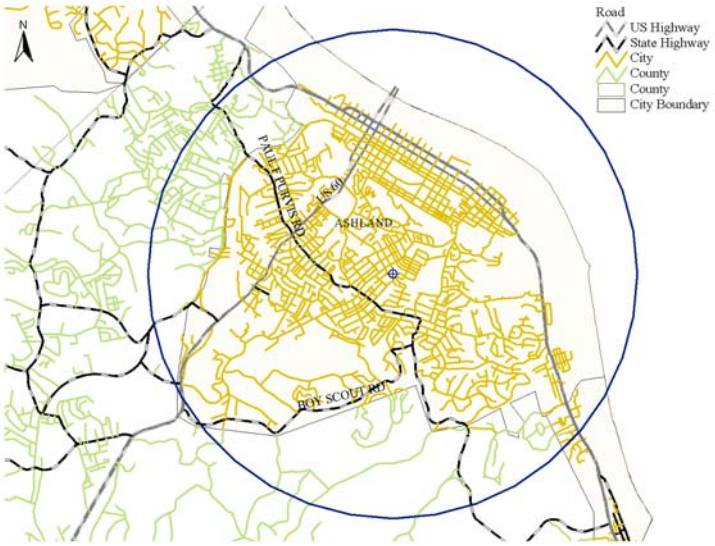
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide	4.3	SLAMS EPISODE	Chemiluminescence	Continuously
AEM Ozone	4.3	SLAMS AQI EPISODE	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.7	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Speciation	4.6	SLAMS	Thermal optical, ion chromatography, and X-ray fluorescence	24-hours every sixth day
$PM_{2.5}$ TEOM	4.7	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously
AEM Sulfur Dioxide	4.3	SLAMS AQI EPISODE	UV fluorescence	Continuously
Volatile Organics Compound	4	SPM	EPA method TO-15	24-hours every sixth day

Carbonyls	3.8	SPM	EPA method TO-11A	24-hours every sixth day
Meteorological	7.7	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

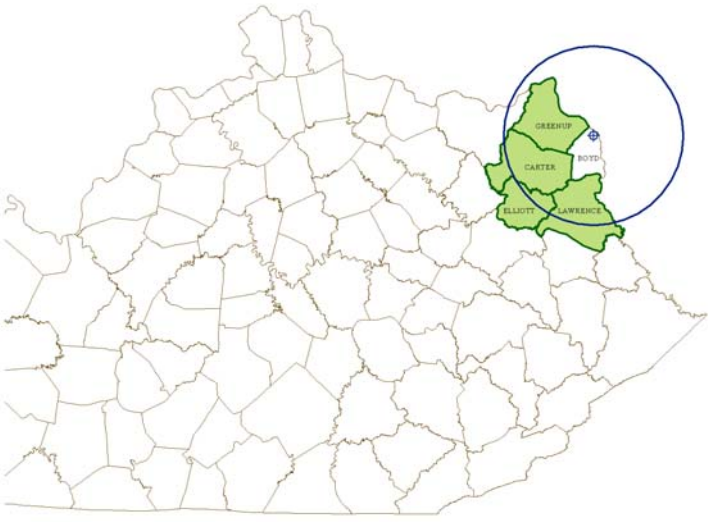
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents maximum concentrations on a middle scale for particulates. This site also represents population exposure on a neighborhood scale for air toxics.

Criteria and Air Toxics Neighborhood Scale



Nitrogen Dioxide Urban Scale



CSA/MSA: Huntington-Ashland, WV-KY-OH MSA
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Worthington
AQS Site ID: 21-089-0007
Location: Scott Street and Center Avenue, Worthington, KY 41183
County: Greenup
GPS Coordinates: 38.548333, -82.731667
Date Established: October 12, 1980
Inspection Date: October 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of a water tower near the intersection of Scott Street and Center Avenue in Worthington, Kentucky. The sample inlets are 57 feet from the nearest road. The most recent site inspection was conducted on October 24, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for nitrogen dioxide, ozone and sulfur dioxide; and to provide pollutant levels for daily air quality index reporting.

Monitors:

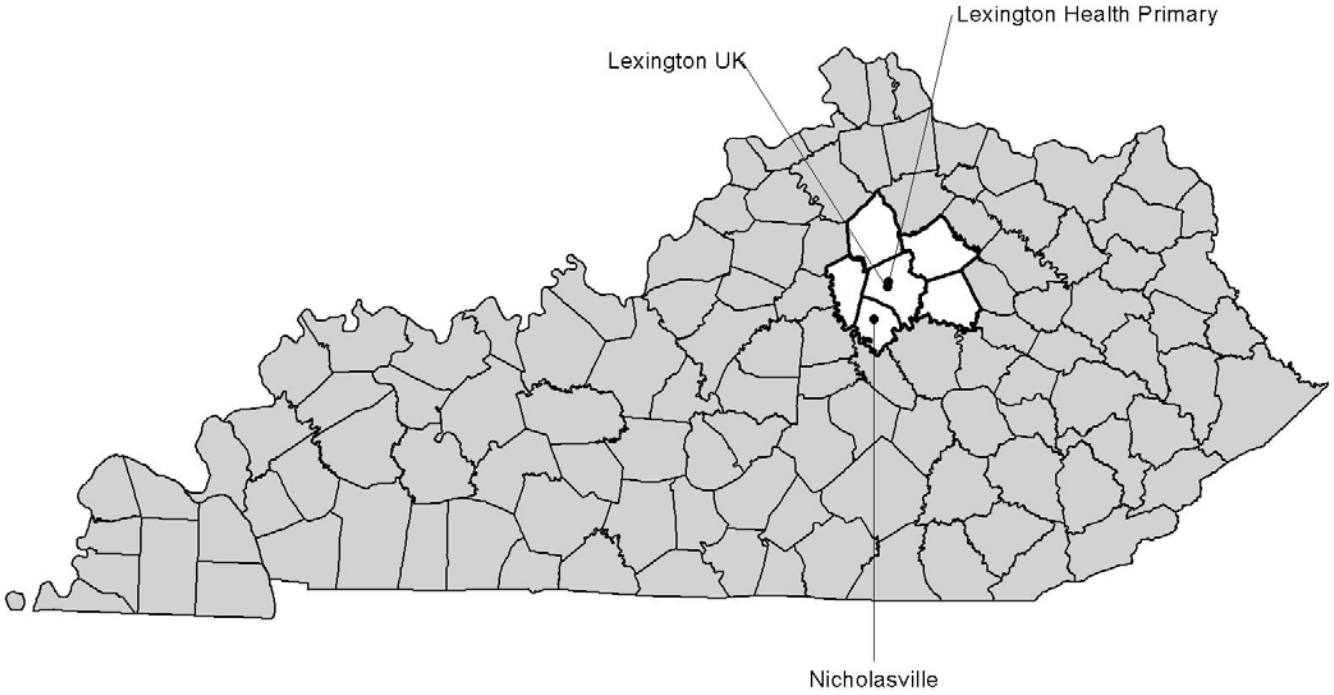
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.2	SLAMS AQI	UV photometry	Continuously March 1 – October 31
AEM Sulfur Dioxide	4.2	SPM	UV fluorescence	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for ozone and sulfur dioxide.

Criteria Neighborhood Scale

Lexington-Fayette, KY



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-067-0012	650 Newtown Pike Lexington (Fayette)	X(t)		X(eI)	X(e)		X (I e)				X(s)	X(s)	X(s)	
21-067-0014	533 South Limestone Lexington (Fayette)	X	X					X(s)						
21-113-0001	KY DOT Garage, US 27 Bypass Nicholasville (Jessamine)			X(s)			X		X	HG				X
	TOTAL	3	1	2	1	0	2	1	1	1	1	1	1	1

(e) Emergency Episode Monitor

(I) Air Quality Index Monitor

(s) Special Purpose Monitor

(t) Continuous PM Monitor

(Rev.6/30/09)

CSA/MSA: Lexington-Fayette-Frankfort-Richmond, KY CSA / Lexington-Fayette, KY MSA
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: Lexington Primary
AQS Site ID: 21-067-0012
Location: Fayette County Health Department, 650 Newtown Pike, Lexington, KY 40508
County: Fayette
GPS Coordinates: 38.065000, -84.500000
Date Established: November 8, 1979
Inspection Date: December 5, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Fayette County health department building in Lexington, Kentucky. The sample inlets are 385 feet from the nearest road. The most recent site inspection was conducted on December 5, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for nitrogen dioxide, ozone and sulfur dioxide; and to provide pollutant levels for daily air quality index reporting.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
ARM Nitrogen Dioxide	4	SLAMS EPISODE	Chemiluminescence	Continuously
AEM Ozone	3.8	SLAMS AQI EPISODE	UV photometry	Continuously March 1 – October 31
FEM $PM_{2.5}$	4.6	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Speciation	4.5	SLAMS	Thermal optical, ion chromatography, and X-ray fluorescence	24-hours every sixth day
$PM_{2.5}$ TEOM	4.6	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously
AEM Sulfur Dioxide	3.6	SLAMS AQI EPISODE	UV fluorescence	Continuously
Volatile Organics Compound	3.5	SPM	EPA method TO-15	24-hours every sixth day
Carbonyls	3.5	SPM	EPA method TO-11A	24-hours every sixth day

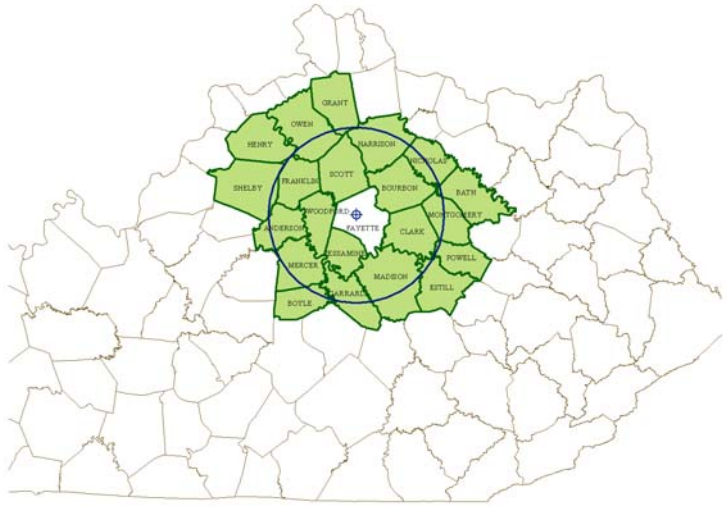
Radiation	4	RadNet	RadNet fixed stationary monitor, manual and automated methods	Continuously & 2 weekly filters

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates, sulfur dioxide and ozone. This site also represents population exposure on an urban scale for nitrogen dioxide and air toxics.

Criteria Neighborhood Scale

Nitrogen Dioxide and Air Toxics Urban Scale



CSA/MSA: Lexington-Fayette-Frankfort-Richmond, KY CSA / Lexington-Fayette, KY MSA
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: U.K. Lexington
AQS Site ID: 21-067-0014
Location: 533 South Limestone, Lexington, KY 40508
County: Fayette
GPS Coordinates: 38.038889, -84.507500
Date Established: October 2, 1982
Inspection Date: December 5, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is located on the roof of the Whalen Transportation Research Building on the University of Kentucky campus in Lexington, Kentucky. The sample inlets are 60 feet from the nearest road. The most recent site inspection was conducted on December 5, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM $PM_{2.5}$	11.2	SLAMS	Gravimetric	24-hourd every third day
FRM PM_{10}	11	SLAMS	Gravimetric	24-hourd every sixth day
- Metals PM_{10}		SPM	Determined from the PM_{10} sample using EPA method IO 3.4	Same as PM_{10}

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale.

Criteria Neighborhood Scale

CSA/MSA: Lexington-Fayette-Frankfort-Richmond, KY CSA / Lexington-Fayette, KY MSA
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: Nicholasville
AQS Site ID: 21-113-0001
Location: DOT Garage, US 27 Bypass, Nicholasville, KY 40356
County: Jessamine
GPS Coordinates: 37.893333, -84.589167
Date Established: August 1, 1991
Inspection Date: December 5, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Kentucky DOT Garage in Nicholasville, Kentucky. The sample inlets are 372 feet from the nearest road. The most recent site inspection was conducted on December 5, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to provide ozone data upwind of the Lexington area; and to provide pollutant levels for daily air quality index reporting.

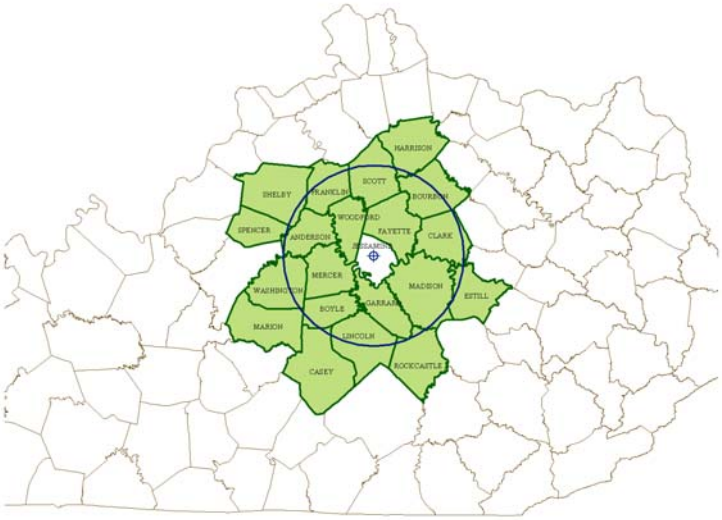
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.9	SLAMS AQI	UV photometry	Continuously March 1 – October 31
AEM Sulfur Dioxide	3.9	SPM AQI	UV fluorescence	Continuously
Mercury - ambient	3.8	SPM	Cold vapour atomic fluorescence spectrometry	Continuously
Mercury – Wet Deposition	1.5	SPM	Wet deposition collected, analysis of sample by the Environmental Services laboratory	Weekly
Meteorological	1.25	Other	Rain gauge	Continuously

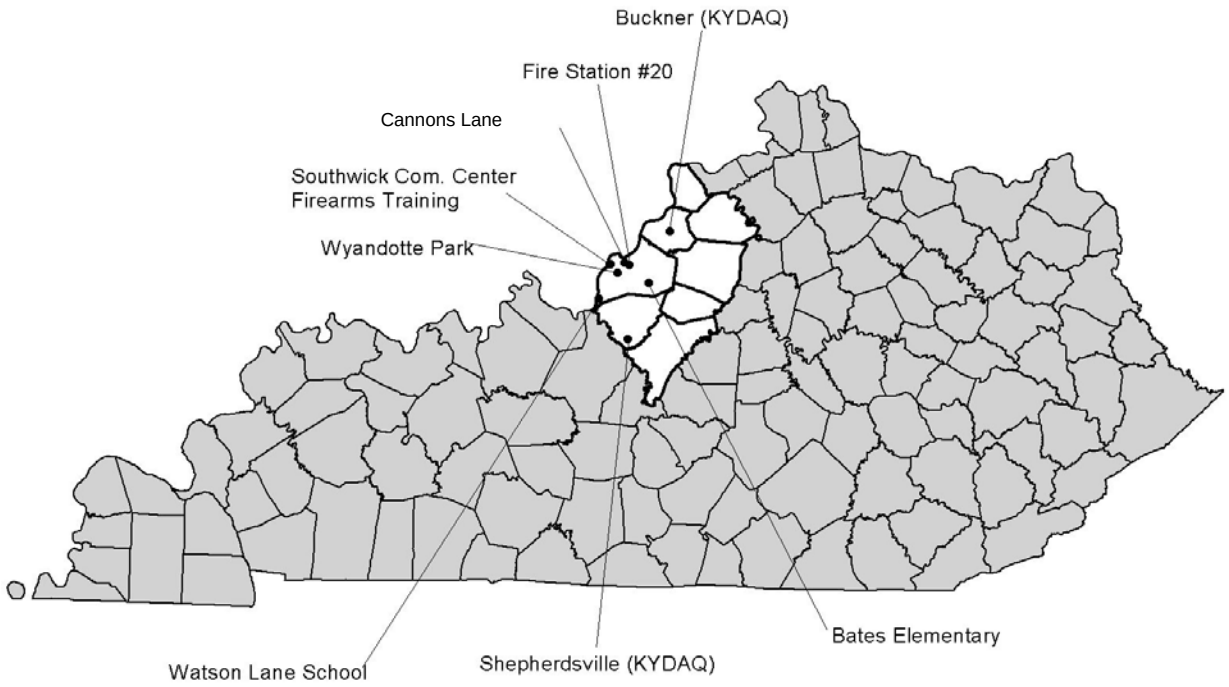
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on an urban scale.

Criteria and Air Toxics Urban Scale



Louisville-Jefferson County, KY-IN



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-029-0006	2nd & Carpenter Streets Shepherdsville (Bullitt)	X					X(I)							X
21-185-0004	DOT Garage, 3995 Morgan Rd Buckner (Oldham)						X(I)							
21-111-0027	7601 Bardstown Road Louisville (Jefferson)	Xt(sI)					X(I)							
21-111-0043	3621 Southern Avenue Louisville (Jefferson)	X(ctI)	X(c)											X
21-111-0044	1032 Beecher Avenue Louisville (Jefferson)	X(I)	X(tI)											
21-111-0051	7201 Watson Lane Louisville (Jefferson)	X(tsI)		X(I)			X(I)							
21-111-0067	2730 Cannons Lane Louisville (Jefferson)	X(tI)	X	X(I)	X(I)	X(I)	X(I)				X		X	X
21-111-1019	1735 Bardstown Road Louisville (Jefferson)					X(I)								
21-111-1041	4201 Algonquin Parkway Louisville (Jefferson)			X(Ie)										
	TOTAL	11	4	3	1	2	5	0	0	0	1	0	1	3

(c) Collocated Monitor
(e) Emergency Episode Monitor
(I) Air Quality Index Monitor
(s) Special Purpose Monitor
(t) Continuous PM Monitor

(Rev. 5/21/09)

CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: North Central Kentucky Intrastate (104)
Site Name: Shepherdsville
AQS Site ID: 21-029-0006
Location: Second and Carpenter Streets, Shepherdsville, KY 40165
County: Bullitt
GPS Coordinates: 37.98556, -85.713056
Date Established: January 30, 1992
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located in a fenced in area near the intersection of Second and Carpenter Streets in Shepherdsville, Kentucky. The sample inlets are 70 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide ozone levels for daily index reporting.

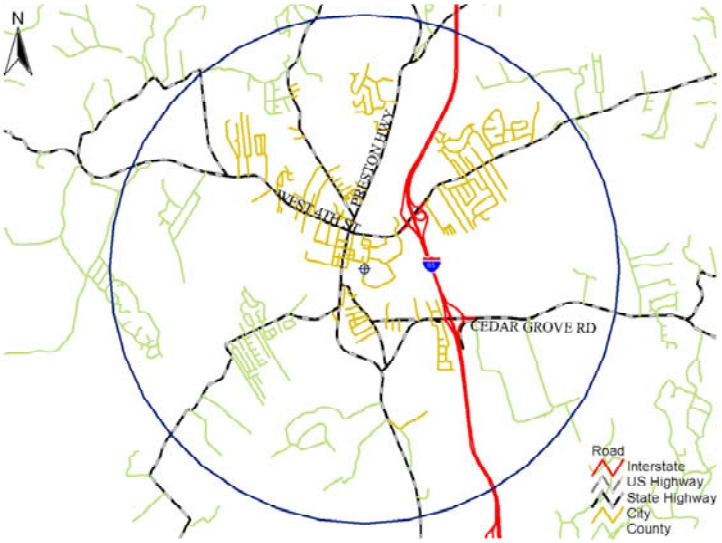
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.3	SPM AQI	UV photometry	Continuously March 1 – October 31
FEM $PM_{2.5}$	4.5	SLAMS	Gravimetric	24-hourd every third day
Meteorological	7.6	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

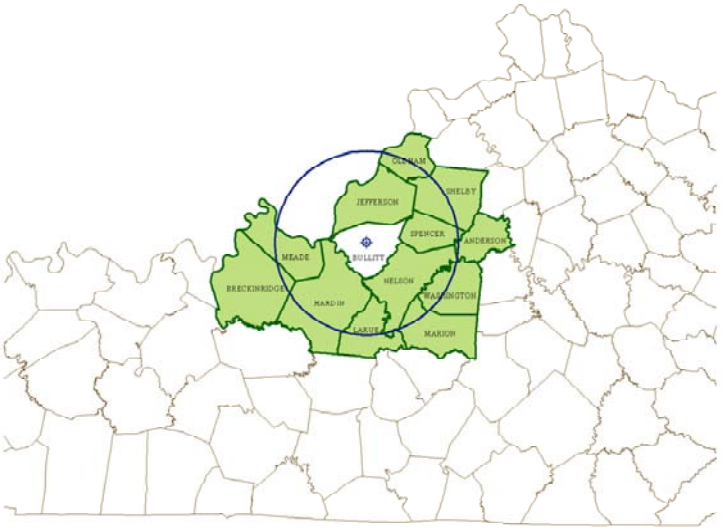
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates and population exposure on an urban scale for ozone.

Particulates Neighborhood Scale



Ozone Urban Scale



CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: North Central Kentucky Intrastate (104)
Site Name: Buckner
AQS Site ID: 21-185-0004
Location: DOT Garage, 3995 Morgan Road, Buckner, KY 40010
County: Oldham
GPS Coordinates: 38.398611, -85.443333
Date Established: May 1, 1981
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Kentucky DOT Highway Garage in Buckner, Kentucky. The sample inlet is 250 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. Upon inspection, the sample line and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide ozone levels for daily index reporting.

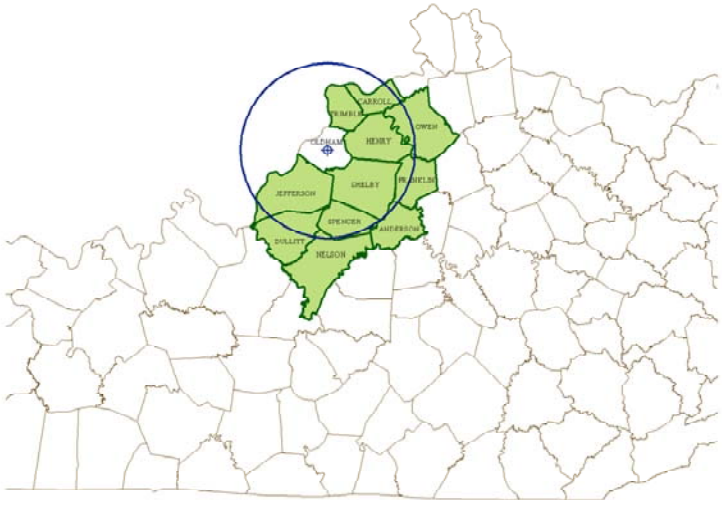
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.3	SPM AQI	UV photometry	Continuously March 1 – October 31

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentrations on an urban scale.

Ozone Urban Scale



CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Bates Elementary
AQS Site ID: 21-111-0027
Location: Bates Elementary, 7601 Bardstown Road, Louisville, KY 40291
County: Jefferson
GPS Coordinates: 38.13784, -85.57648
Date Established: January 4, 1973
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Bates Elementary School in Louisville, Kentucky. The sample inlets are 13 feet above ground level and 1000 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. The air monitoring site was found to be in accordance with 40 CFR Part 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

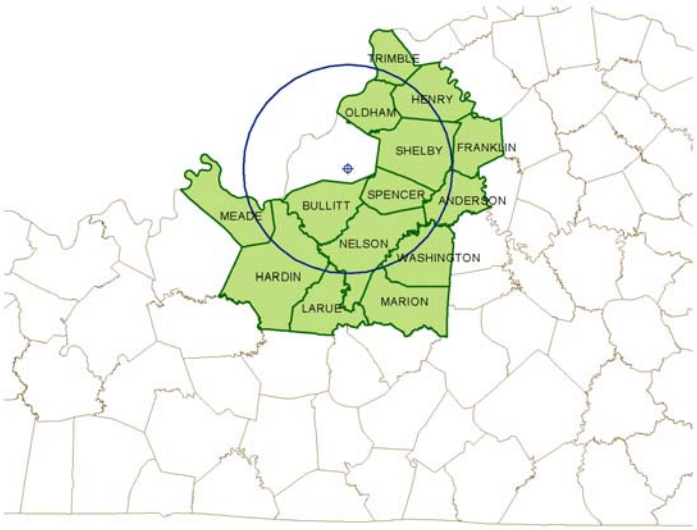
Monitors:

Monitor Type	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	SLAMS AQI	UV photometry	Continuously March 1 – October 31
$PM_{2.5}$ TEOM	Other AQI	Tapered element oscillating microbalance, gravimetric	Continuously

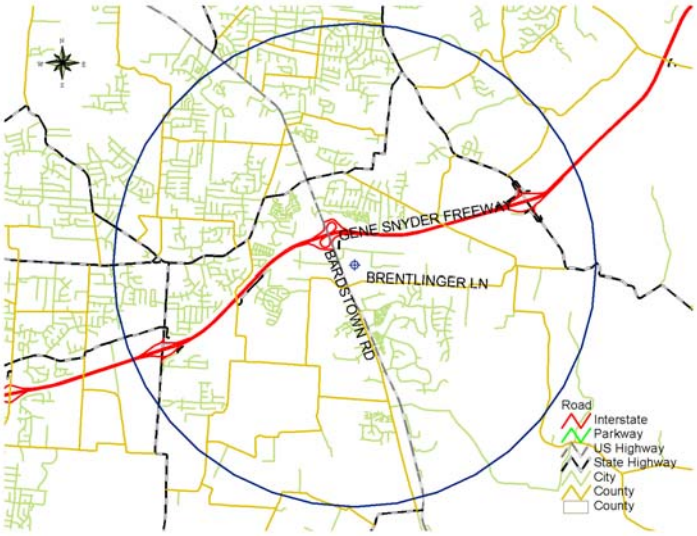
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on an urban scale for ozone. This site also represents population exposure on a neighborhood scale for fine particulates.

Ozone Urban Scale



Particulates Neighborhood Scale



CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Southwick Community Center
AQS Site ID: 21-111-0043
Location: Southwick Community Center, 3621 Southern Avenue, Louisville, KY 40211
County: Jefferson
GPS Coordinates: 38.23319, -85.81566
Date Established: July 1, 1983
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is located on the roof of the Southwick Community Center in Louisville, Kentucky. The sample inlets are 16 feet above ground level and 200 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. The air monitoring site was found to be in accordance with 40 CFR Part 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

Monitors:

Monitor Type	Designation	Analysis Method	Frequency of Sampling
PM_{10} TEOM	AQI	Tapered element oscillating microbal-ance, gravimetric	Continuously
- Collocated PM_{10} TEOM	AQI	Tapered element oscillating microbal-ance, gravimetric	Continuously
FRM $PM_{2.5}$	SLAMS	Gravimetric	24-hours everyday
- Collocated FRM $PM_{2.5}$	Other	Gravimetric	24-hours every sixth day
$PM_{2.5}$ TEOM	Other AQI	Tapered element oscillating microbal-ance, gravimetric	Continuously
Meteorological	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure, rainfall and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates.

Neighborhood Scale

CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Wyandotte Park
AQS Site ID: 21-111-0044
Location: Wyandotte Park, 1032 Beecher Avenue, Louisville, KY 40215
County: Jefferson
GPS Coordinates: 38.19113, -85.77935
Date Established: September 1, 1983
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is located on the roof of the recreation building at Wyandotte Park in Louisville, Kentucky. The sample inlets are 16 feet above ground level and 150 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. The air monitoring site was found to be in accordance with 40 CFR Part 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

Monitors:

Monitor Type	Designation	Analysis Method	Frequency of Sampling
PM_{10} TEOM	AQI	Tapered element oscillating microbalance, gravimetric	Continuously
FRM $PM_{2.5}$	SLAMS	Gravimetric	24-hours everyday

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale.

Neighborhood Scale

CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Watson Lane
AQS Site ID: 21-111-0051
Location: Watson Lane School, 7201 Watson Lane, Louisville, KY 40272
County: Jefferson
GPS Coordinates: 38.06091, -85.89804
Date Established: July 16, 1992
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Watson Lane Elementary School in Louisville, Kentucky. The sample inlets are 13 feet above ground level and 125 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. The air monitoring site was found to be in accordance with 40 CFR Part 58, Appendices C, D, E and G.

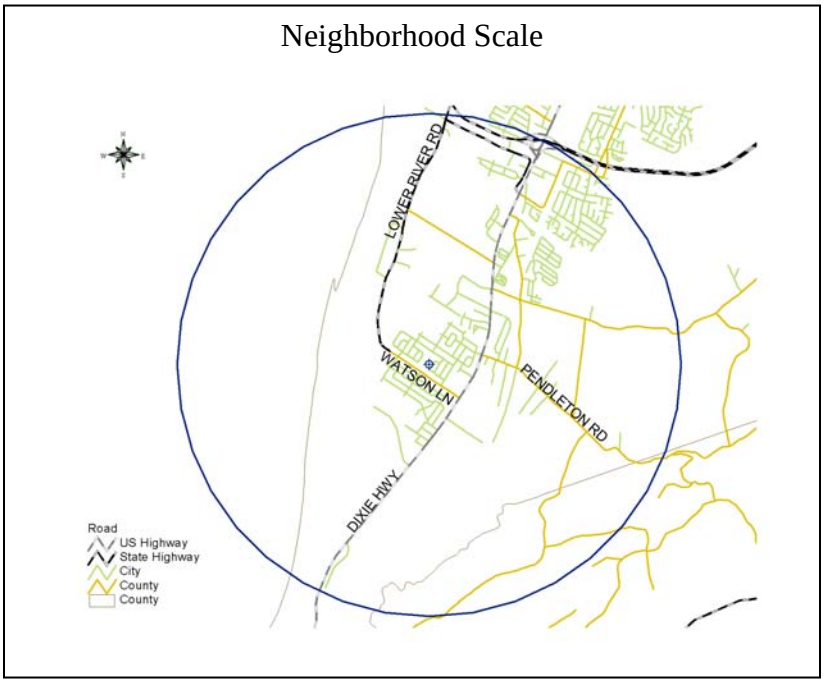
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

Monitors:

Monitor Type	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	SLAMS AQI	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	Other	Gravimetric	24-hours every sixth day
$PM_{2.5}$ TEOM	Other AQI	Tapered element oscillating microbal-ance, gravimetric	Continuously
AEM Sulfur Dioxide	SLAMS AQI	UV fluorescence	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale.



CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Cannons Lane
AQS Site ID: 21-111-0067
Location: 2730 Cannons Lane, Louisville, KY 40204
County: Jefferson
GPS Coordinates: 38.22883, -85.6544
Date Established: January 1, 2009
Inspection Date: April 17, 2008 (KYDAQ), December 9, 2008 (US EPA)
Inspection By: Andrea P. Keatley (KYDAQ), Richard Guillot and Jerry Burger (US EPA)
Site Approval Status: EPA SLAMS approval on December 22, 2008, NCORE approval is pending

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The station is located on property leased by LMAPCD. The property was used as a Vehicle Emissions Testing (VET) center but is now used primarily for storage. The location is in the NE quadrant of Jefferson County and is approximately 9 km from the urban core of Metro Louisville.

Monitoring Objective:

The NCore Network addresses the following monitoring objectives:

- timely reporting of data to the public through AIRNow, air quality forecasting, and other public reporting mechanisms
- support development of emission strategies through air quality model evaluation and other observational methods
- accountability of emission strategy progress through tracking long-term trends of criteria and non-criteria pollutants and their precursors
- support long-term health assessments that contribute to ongoing reviews of the National Ambient Air Quality Standards (NAAQS)
- compliance through establishing nonattainment/attainment areas by comparison with the NAAQS
- support multiple disciplines of scientific research, including public health, atmospheric and ecological

Monitors:

Monitor Type	Designations	Analysis Method	Frequency of Sampling	Startup Date
Carbon Monoxide (CO)	NCore AQI	Automated Reference Method* utilizing trace level non-dispersive infrared analysis.	Continuously	01/01/2010
Nitrogen Oxide (NO_x)	NCore AQI	Automated Reference Method utilizing chemiluminescence analysis.	Continuously	01/01/2010
Ozone (O_3)	NCore AQI	Automated Equivalent Method utilizing UV photometry analysis.	Continuously	01/01/2010
Sulfur Dioxide (SO_2)	NCore AQI	Automated Equivalent Method utilizing trace level UV fluorescence analysis	Continuously	01/01/2010
Total Reactive Nitrogen (NO/ NO_y)	NCore	Automated method utilizing trace level chemiluminescence analysis.	Continuously	01/01/2011
$PM_{2.5}$ Filter	NCore	Manual Reference Method utilizing gravimetric analysis.	1/3 days	01/01/2009
$PM_{2.5}$ Continuous	NCore AQI	Automated Equivalent Method* utilizing Tapered Element Oscillating Microbalance/gravimetric analysis	Continuously	01/01/2009
$PM_{2.5}$ Speciation	NCore	Multi-species manual collection method utilizing thermal optical, ion chromatography, gravimetric, and X-ray fluorescence analyses.	1/6 days 1/3 days	01/01/2009 01/01/2011
PM_{10c} Filter	NCore	Manual Reference Method* PM_{10c} utilizing differential gravimetric analysis.	1/3 days	01/01/2009
$PM_{10-2.5}$ Speciation	NCore	Method pending	1/3 days	Requirement under review
Meteorological	NCore	Air Quality Measurements approved instrumentation for wind speed, wind direction, humidity, temperature, rainfall, and solar radiation	Continuously	07/01/2009
Lead	SLAMS	Manual Reference Method TSP Sampler, Analytical method to be determined.	1/6	01/01/2011
Radiation	RadNet	RadNet fixed station air monitor, manual and automated methods	Continuously + 2 weekly filters	01/01/2009
Volatile Organic Compounds	SPM	EPA Compendium Method TO-15 utilizing Summa® passivated canisters	1/12	02/10/2009

* Pending EPA designation

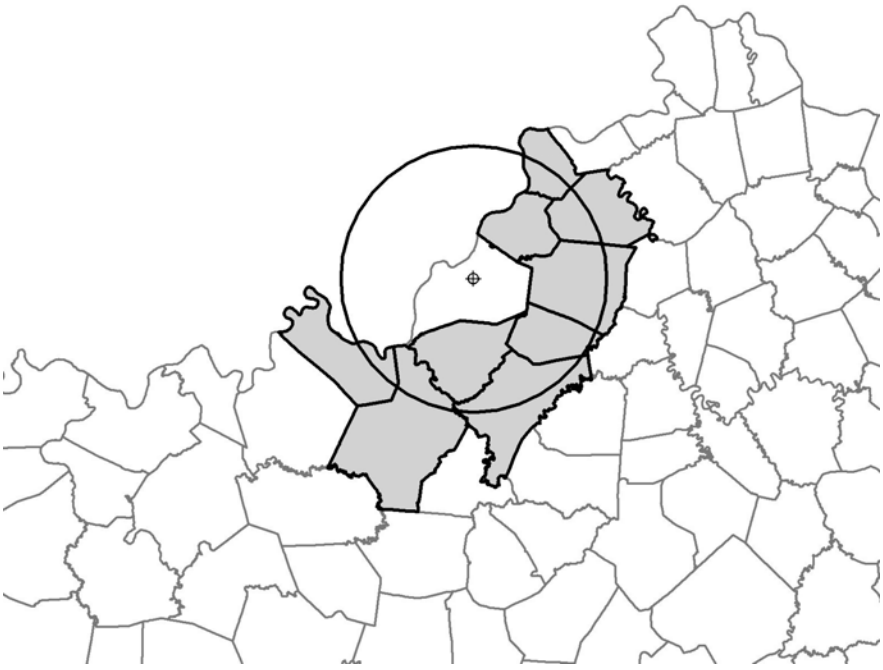
Quality Assurance Status:

All Quality Assurance procedures shall be implemented in accordance with 40 CFR 58, Appendix A. The District's current Quality Assurance Project Plan covers $PM_{2.5}$, Ozone, NOx, SO_2, CO, $PM_{2.5}$ Speciation, and meteorological measurements. The Quality Assurance Project Plan will be revised to include trace level measurements and lead. Standard operating procedures manuals will be adopted or developed for new instrumentation.

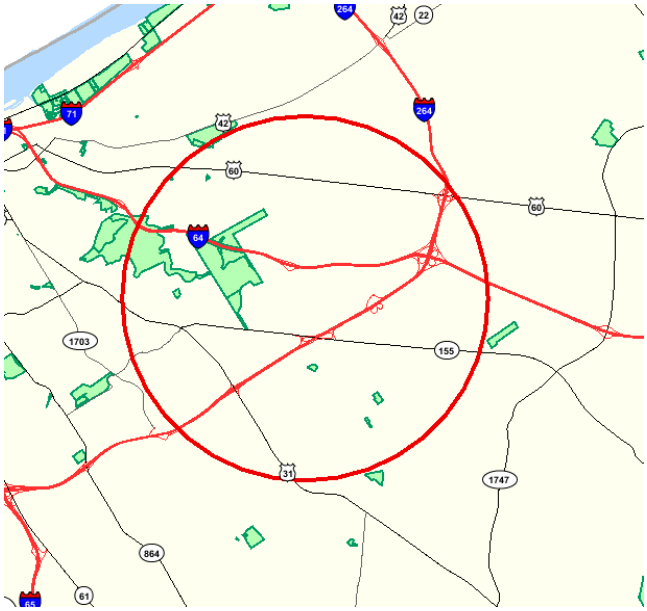
Area Representativeness:

Pollutant	Spatial Scale	Comments
Ozone	Neighborhood and Urban Scale	Use 10 km
NO_x /NO_y	Neighborhood and Urban Scale	Use 10 km
Carbon Monoxide	Neighborhood Scale	There is no Urban scale for CO
SO_2	Neighborhood Scale	There is no Urban scale for SO_2
PM_{10}/$PM_{2.5}$/Lead	Urban	
Radiation	Urban	
VOCs	Neighborhood	

Ozone, $PM_{2.5}$, PM_{10}, and NO_x urban scale (50 km)



CO neighborhood scale (4 km)



CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Fire Station 20
AQS Site ID: 21-111-1019
Location: Fire Station 20, 1735 Bardstown Road, Louisville, KY 40205
County: Jefferson
GPS Coordinates: 38.229, -85.7018
Date Established: January 1, 1973
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is located at Fire Station Number 20 on Bardstown Road in Louisville, Kentucky. The sample inlet is 10 feet above ground level and 13 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. The air monitoring site was found to be in accordance with 40 CFR Part 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

Monitors:

Monitor Type	Designation	Analysis Method	Frequency of Sampling
ARM Carbon Monoxide	SLAMS AQI	Non-dispersive infrared	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentration on a micro scale.

Micro Scale

CSA/MSA: Louisville-Jefferson County-Elizabethtown-Scottsburg, KY-IN CSA / Louisville-Jefferson, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Firearms Training
AQS Site ID: 21-111-1041
Location: Firearms Training, 4201 Algonquin Parkway, Louisville, KY 40211
County: Jefferson
GPS Coordinates: 38.23158, -85.82678
Date Established: April 13, 1978
Inspection Date: November 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Firearms Training Center in Louisville, Kentucky. The sample inlet is 15 feet above ground level and 100 feet from the nearest road. The most recent site inspection was conducted on November 24, 2008. The air monitoring site was found to be in accordance with 40 CFR Part 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect episode levels for the activation of emergency control procedures; and to provide pollution levels for daily index reporting.

Monitors:

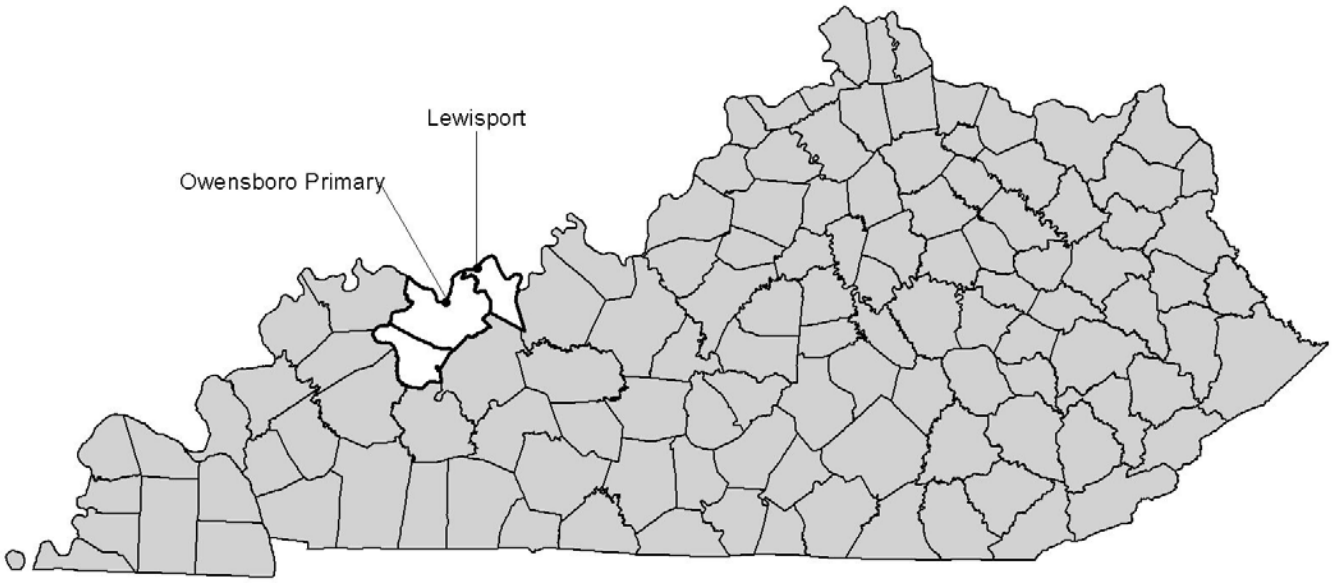
Monitor Type	Designation	Analysis Method	Frequency of Sampling
AEM Sulfur Dioxide	SLAMS EPISODE AQI	UV fluorescence	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale.

Neighborhood Scale

Owensboro, KY



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Metals	Hg	Wet Dep.	VOC	Carb -onyl	Specia- tion	MET
21-059-0005	716 Pleasant Valley Road Owensboro (Daviess)	X(tIe)		X(eI)	X(e)		X(eI)							X
21-091-0012	Lewisport Elementary School Lewisport (Hancock)						X							
	TOTAL	2	0	1	1	0	2	0	0	0	0	0	0	1

(e) Emergency Episode Monitor
(I) Air Quality Index Monitor
(t) Continuous PM Monitor

(Rev.5/23/08)

CSA/MSA: Owensboro, KY MSA
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Owensboro Primary
AQS Site ID: 21-059-0005
Location: 716 Pleasant Valley Road, Owensboro, KY 42303
County: Daviess
GPS Coordinates: 37.780833, -87.075556
Date Established: December 1, 1970
Inspection Date: December 17, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds behind the Wyndall's Shopping Center in Owensboro, Kentucky. The sample inlets are 200 feet from the nearest road. The most recent site inspection was conducted on December 17, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect emergency pollution levels of criteria pollutants for activation of emergency control procedures; and to provide levels of pollutants for daily index reporting.

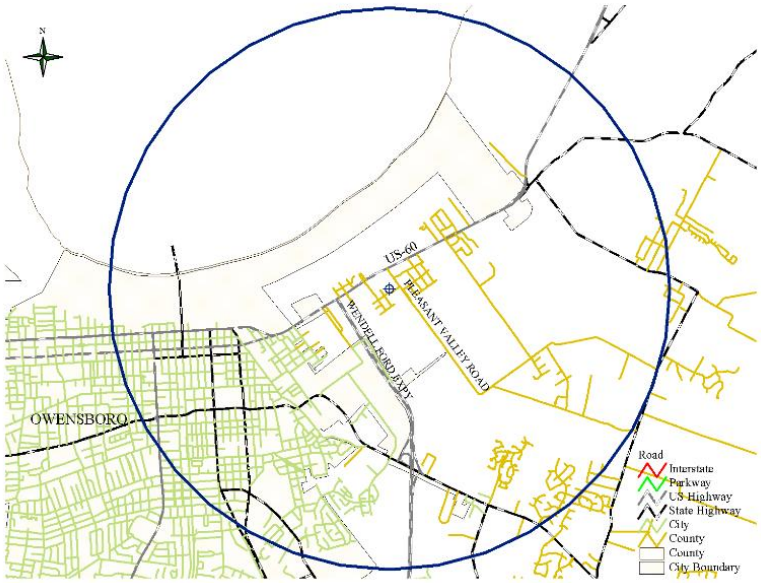
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide	3.5	SLAMS EPISODE	Chemiluminescence	Continuously
AEM Ozone	3.5	SLAMS EPISODE AQI	UV photometry	Continuously March 1 – October 31
FEM $PM_{2.5}$	4.5	SLAMS EPISODE AQI	Gravimetric	24-hours every third day
$PM_{2.5}$ TEOM	4.5	SPM	Tapered element oscillating microbalance, gravimetric	Continuously
AEM Sulfur Dioxide	3.5	SLAMS EPISODE AQI	UV fluorescence	Continuously
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

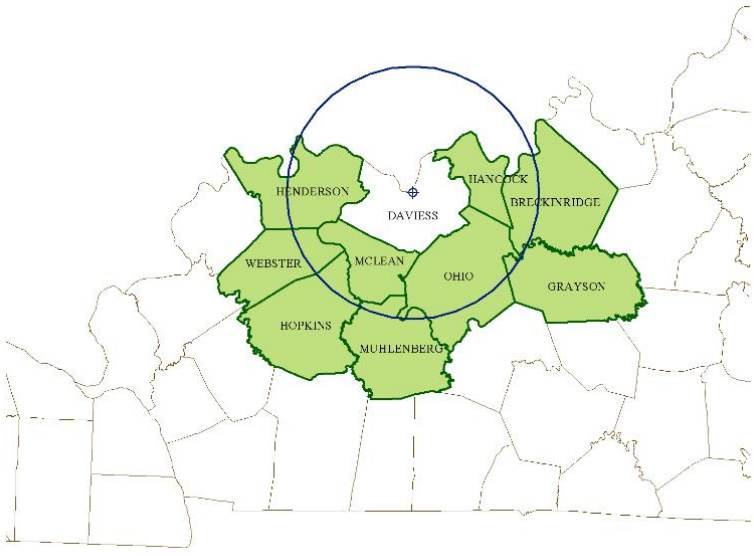
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates, ozone and sulfur dioxide. This site also represents population exposure on an urban scale for nitrogen dioxide.

Criteria Neighborhood Scale



Nitrogen Dioxide Urban Scale



CSA/MSA: Owensboro, KY MSA
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Lewisport
AQS Site ID: 21-091-0012
Location: Second and Caroline Streets, Lewisport Elementary School, Lewisport, KY 42351
County: Hancock
GPS Coordinates: 37.938889, -86.896944
Date Established: September 5, 1980
Inspection Date: December 17, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Lewisport Elementary School in Lewisport, Kentucky. The sample inlet is 175 feet from the nearest road. The most recent site inspection was conducted on December 17, 2008. Upon inspection, the sample line and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

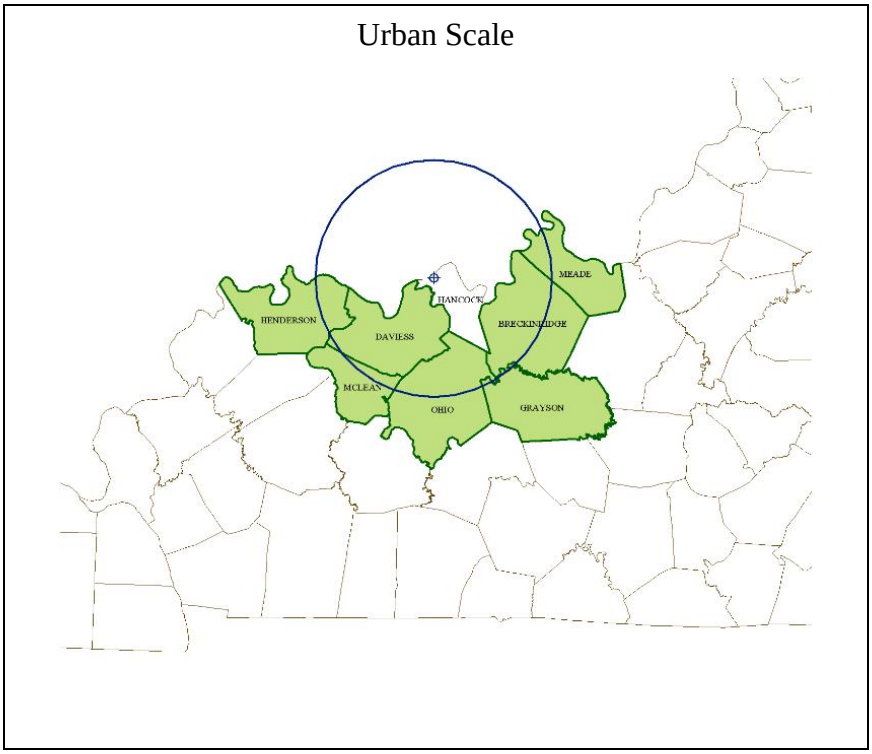
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide levels of ozone for daily index reporting.

Monitors:

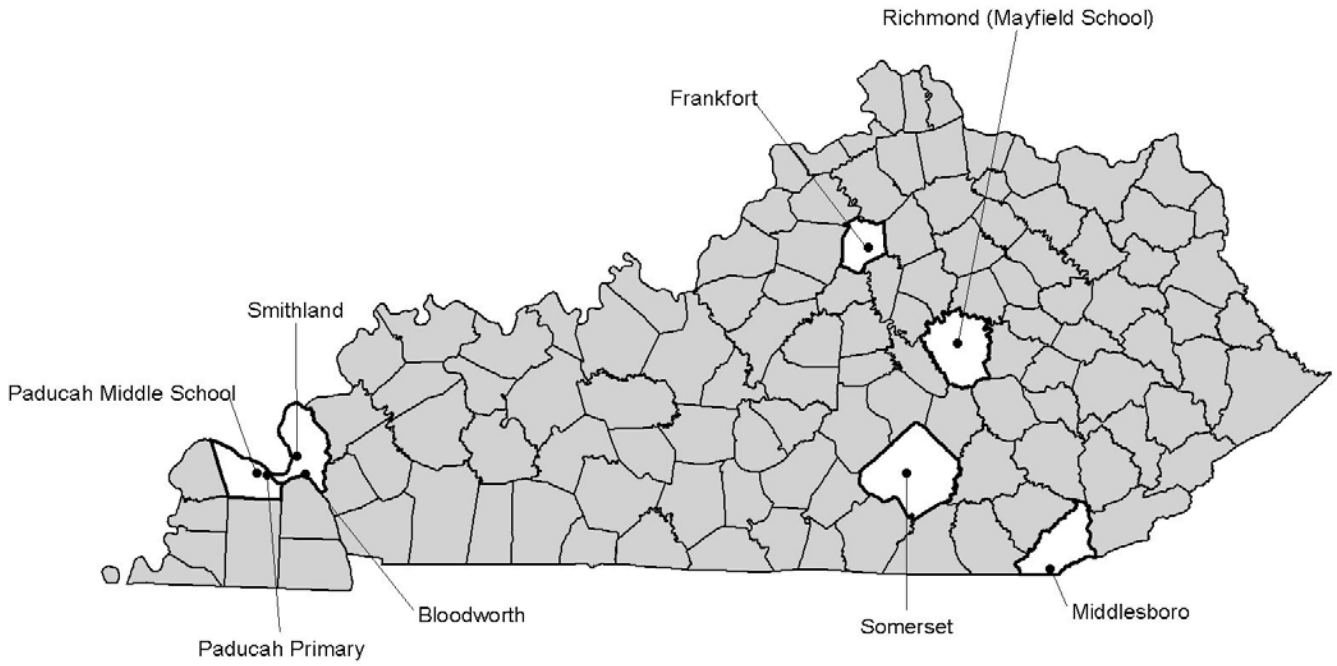
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.5	SLAMS AQI	UV photometry	Continuously March 1 – October 31

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentration on an urban scale.



Micropolitan Statistical Areas



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Pb/ Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-013-0002	Airport, 34th & Dorchester Middlesboro (Bell)	X(s)					X(s)							X
21-073-0006	803 Schenkel Lane Frankfort (Franklin)	X												
21-139-0003	DOT Garage, 811 Hwy 60 East Smithland (Livingston)			X			X		X	HG				
21-139-0004	763 Bloodworth Road Livingston County										X			X
21-145-1004	Paducah Middle School, 342 Lone Oak Rd Paducah (McCracken)	X	X											
21-145-1024	J-P RECC, 2901 Powell Street Paducah (McCracken)	Xt(Ie)		X(eI)	X(e)		X(eI)							
21-151-0003	Mayfield Elementary, Bond St. Richmond (Madison)	X						X(c)						
21-199-0003	Somerset Gas Co., Clifty Street Somerset (Pulaski)						X(s)							
	TOTAL	5	1	2	1	0	4	1	1	1	1	0	0	2

(c) Collocated Monitor

(e) Emergency Episode Monitor

(I) Air Quality Index Monitor

(t) Continuous PM Monitor

(Rev.5/22/09)

CSA/MSA: Middlesborough, KY Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Appalachian Intrastate (101)
Site Name: Middlesboro
AQS Site ID: 21-013-0002
Location: Middlesboro Airport, Middlesboro, KY 40965
County: Bell
GPS Coordinates: 36.608056, -83.736944
Date Established: February 14, 1992
Inspection Date: November 27, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Middlesboro Airport in Middlesboro, Kentucky. The sample inlets are 55 feet from the nearest road. The most recent site inspection was conducted on November 27, 2008. Upon inspection the sample lines and monitors were found to be in good condition. Even though this site is for special purpose monitoring, the site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to provide pollutant levels for daily index reporting; and to provide information on the transport of ozone into the region.

Monitors:

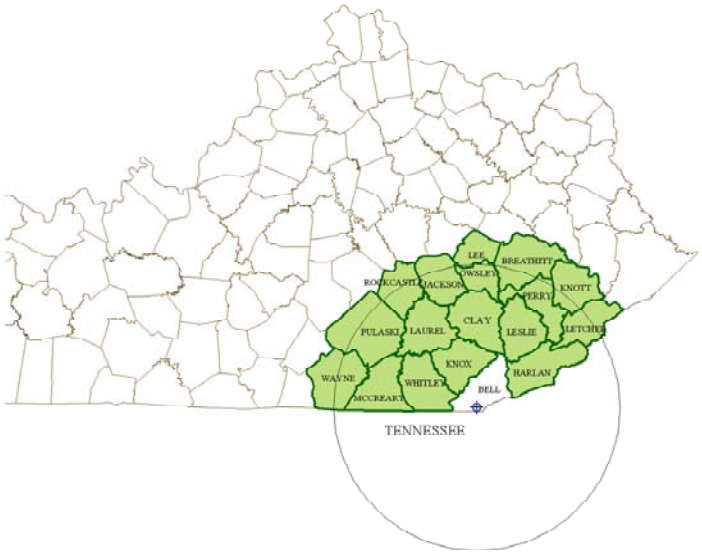
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4	SPM AQI	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.5	SPM	Gravimetric	24-hours every third day
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale for particulates. This site also represents transport on a regional scale for ozone.

Particulate Neighborhood Scale

Ozone Regional Scale



CSA/MSA: Lexington-Fayette-Frankfort-Richmond, KY CSA / Frankfort, KY Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: Frankfort
AQS Site ID: 21-073-0006
Location: 803 Schenkel Lane, Frankfort, KY 40601
County: Franklin
GPS Coordinates: 38.219361, -84.838500
Date Established: January 1, 1999
Inspection Date: December 5, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is located on the roof of the Ragland Building in Frankfort, Kentucky. The sample inlet is 250 feet from the nearest road. The most recent site inspection was conducted on December 5, 2008. Upon inspection, the sample inlet and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FEM $PM_{2.5}$	5.5	SLAMS	Gravimetric	24-hours every third day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale.

Criteria Neighborhood Scale

CSA/MSA: Paducah-Mayfield, KY-IL CSA / Paducah, KY-IL Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Paducah-Cairo Interstate (072)
Site Name: Smithland
AQS Site ID: 21-139-0003
Location: KY DOT Garage, 811 HWY 60 East, Smithland, KY 42081
County: Livingston
GPS Coordinates: 37.155556, -88.393056
Date Established: April 1, 1988
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the KY DOT Highway Garage in Smithland, Kentucky. The sample inlets are 1200 feet from the nearest road. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

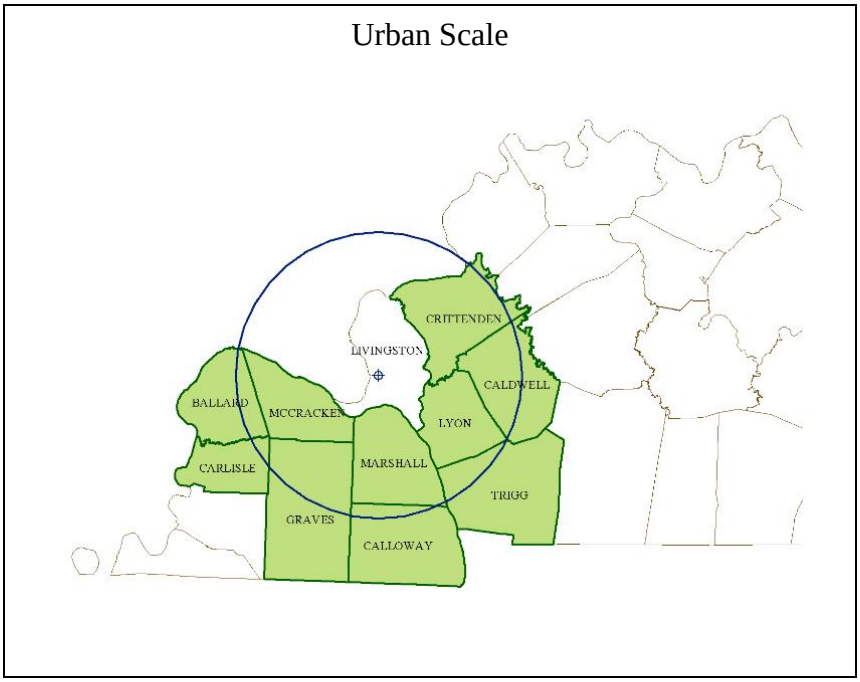
Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.8	SLAMS AQI	UV photometry	Continuously March 1 – October 31
AEM Sulfur Dioxide	3.9	SPM	UV fluorescence	Continuously
Mercury – ambient	3.9	SPM	Cold vapour fluorescence spectrometry	Continuously
Mercury – Wet Deposition		SPM	Wet deposition collected, analysis of sample by the Environmental Services Laboratory	Weekly

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentration on an urban scale.



CSA/MSA: Paducah-Mayfield, KY-IL CSA / Paducah, KY-IL Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Paducah-Cairo Interstate (072)
Site Name: Bloodworth
AQS Site ID: 21-139-0004
Location: 763 Bloodworth Road, Smithland, KY 42081
County: Livingston
GPS Coordinates: 37.070833, -88.334167
Date Established: September 15, 1986
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located at the residence of 763 Bloodworth Road in Livingston County, Kentucky. The sample inlets are 1200 feet from the nearest road. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample lines and samplers were found to be in good condition.

Monitoring Objective:
The monitoring objectives are to determine if air toxics are present in the ambient air and to quantify them.

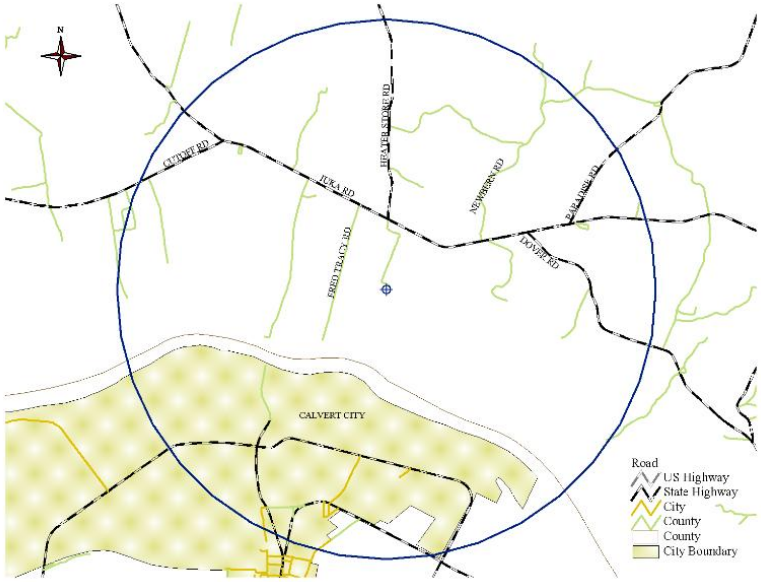
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Volatile Organic Compounds	4.3	SPM	EPA method TO-15	24-hours every sixth day
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents source impact on a neighborhood scale.

Neighborhood Scale



CSA/MSA: Paducah-Mayfield, KY-IL CSA / Paducah, KY-IL Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Paducah-Cairo Interstate (072)
Site Name: Paducah Middle School
AQS Site ID: 21-145-1004
Location: Paducah Middle School, 342 Lone Oak, Paducah, KY 42001
County: McCracken
GPS Coordinates: 37.065556, -88.637778
Date Established: July 1, 1969
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is located on the roof of the Paducah Middle School in Paducah, Kentucky. The sample inlets are 110 feet from the nearest road. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FEM $PM_{2.5}$	11	SLAMS	Gravimetric	24-hours every third day
FRM PM_{10}	11	SLAMS	Gravimetric	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale.

Neighborhood Scale

CSA/MSA: Paducah-Mayfield, KY-IL CSA / Paducah, KY-IL Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Paducah-Cairo Interstate (072)
Site Name: Jackson Purchase Paducah Primary
AQS Site ID: 21-145-1024
Location: Jackson Purchase RECC, 2901 Powell Street, Paducah, KY 42003
County: McCracken
GPS Coordinates: 37.058056, -88.572500
Date Established: August 15, 1980
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Jackson Purchase RECC in Paducah, Kentucky. The sample inlets are 31 feet from the nearest road. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for nitrogen dioxide, ozone and sulfur dioxide; and to provide pollutant levels for daily air quality index reporting.

Monitors:

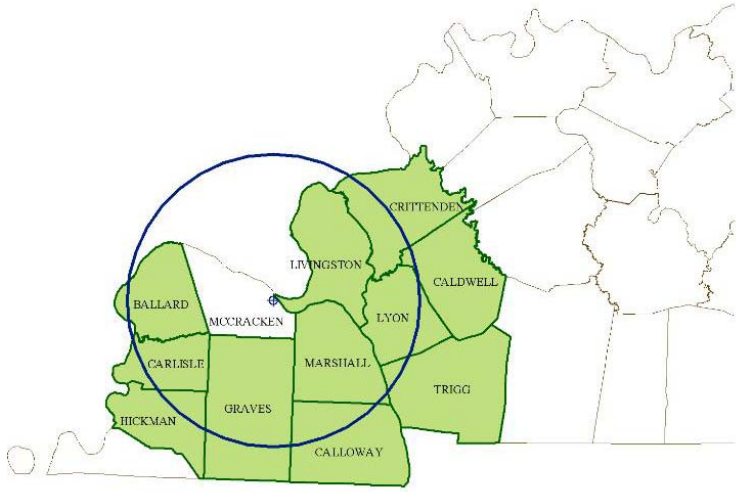
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide	3.7	SLAMS EPISODE	Chemiluminescence	Continuously
AEM Ozone	3.7	SLAMS AQI EPISODE	UV photometry	Continuously March 1 – October 31
$PM_{2.5}$ TEOM	4.7	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously
AEM Sulfur Dioxide	3.7	SLAMS AQI EPISODE	UV fluorescence	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for ozone, particulates and sulfur dioxide. This site also represents population exposure on an urban scale for nitrogen dioxide.

Neighborhood Scale

Nitrogen Dioxide Urban Scale



CSA/MSA: Lexington-Fayette-Frankfort-Richmond, KY CSA / Richmond-Berea, KY Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: Richmond
AQS Site ID: 21-151-0003
Location: Mayfield School, Bond Street, Richmond, KY 40475
County: Madison
GPS Coordinates: 37.738056, -84.285556
Date Established: January 1, 1999
Inspection Date: December 5, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is located on the roof of the Mayfield Elementary School in Richmond, Kentucky. The sample inlet is 200 feet from the nearest road. The most recent site inspection was conducted on December 5, 2008. Upon inspection, the sample inlet and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E. This site will also be the location for a source-oriented lead monitor in January 2010.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM $PM_{2.5}$	6.6	SLAMS	Gravimetric	24-hours every third day
FRM Lead		SLAMS	40 CFR Part 50 Appendix G	24-hours every sixth day
-Collocated FRM Lead		SLAMS	40 CFR Part 50 Appendix G	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates. This site also represents source impact on a neighborhood scale for lead.

Criteria Neighborhood Scale

Lead Neighborhood Scale at 1 km

CSA/MSA: Somerset, KY Micropolitan Statistical Area
401 KAR 50:020 Air Quality Control Region: South Central Kentucky Intrastate (105)
Site Name: Somerset
AQS Site ID: 21-199-0003
Location: Somerset Gas Company, Clifty Street, Somerset, KY 42501
County: Pulaski
GPS Coordinates: 37.097500, -84.611667
Date Established: February 14, 1992
Inspection Date: November 26, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Somerset Gas Company Warehouse on Clifty Street in Somerset, KY. The sample inlets are 35 feet from the nearest road. The most recent site inspection was conducted on November 26, 2008. Upon inspection the sample line and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide levels of ozone and particulate matter for daily index reporting.

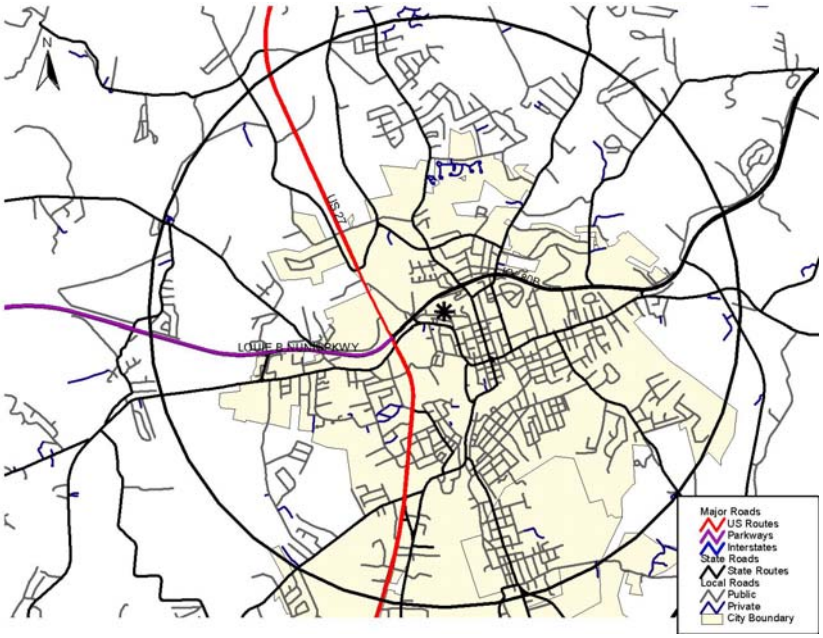
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4	SPM AQI	UV photometry	Continuously March 1 – October 31
$PM_{2.5}$ BAM		SPM AQI	Beta Attenuation Mass Monitor	Continuously

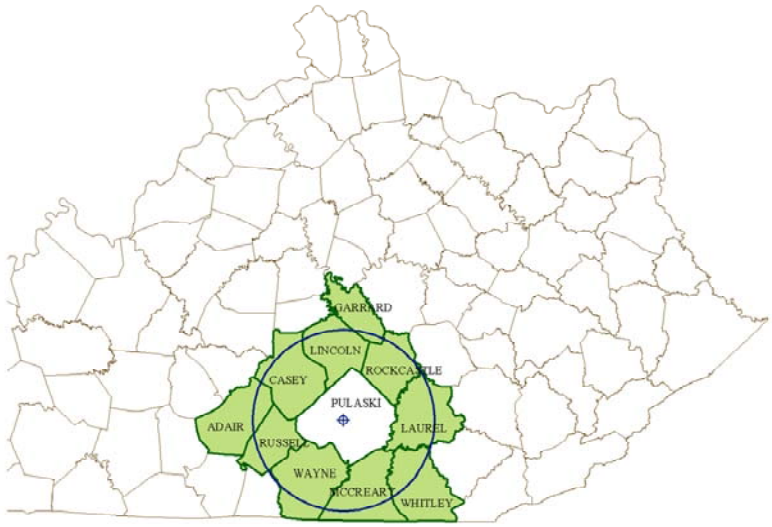
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on an urban scale for ozone. This site also represents population exposure on a neighborhood scale for particulates.

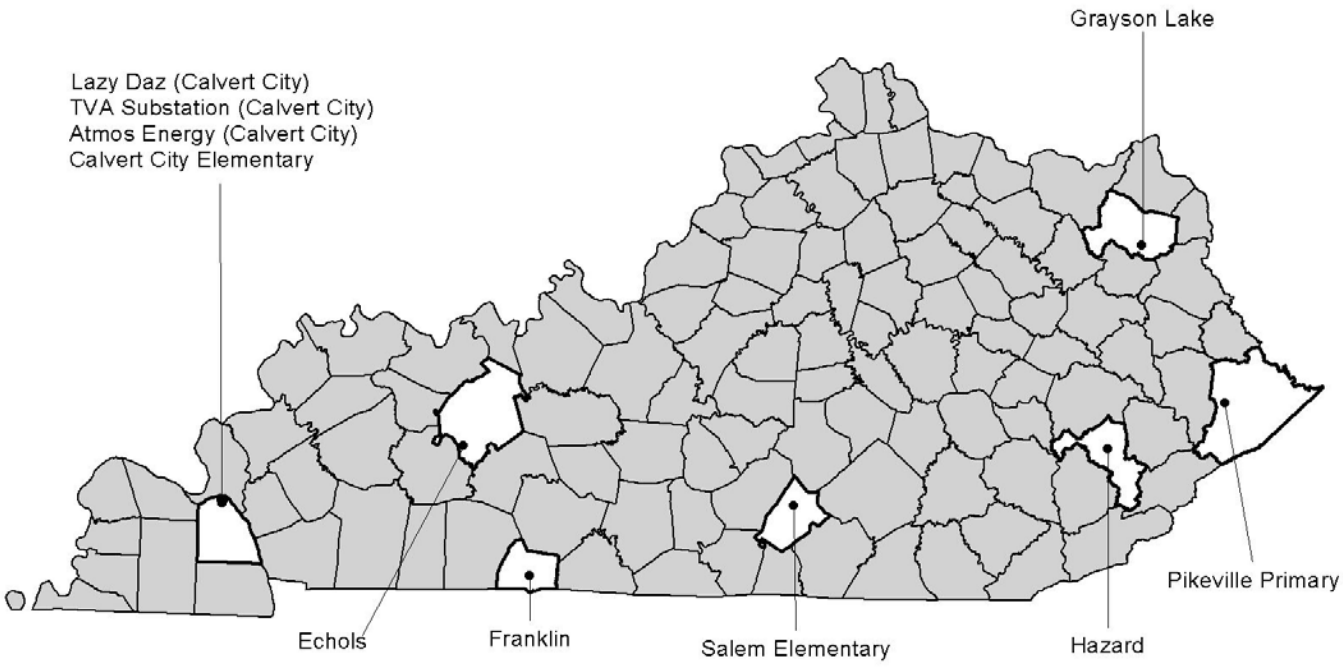
Neighborhood Scale



Ozone Urban Scale



Not in a MSA



AIRS ID	ADDRESS	PM2.5	PM10	SO2	NO2	CO	O3	Pb/ Metals	Hg	Wet Dep.	VOC	Carb-onyl	Specia-tion	MET
21-043-0500	Camp Webb, Grayson Lake Grayson (Carter)	X	X(c)				X(s)	X(c)	X	X HG	X	X	X	X
21-157-0014	TVA Substation Calvert City (Marshall)										X(c)			
21-157-0016	Atmos Energy Calvert City (Marshall)										X			
21-157-0018	Calvert City Elementary Calvert City (Marshall)		X(s)					X			X			
21-157-0019	4237 Gilbertsville Hwy Calvert City (Marshall)										X			
21-183-0032	Keytown Road Echols (Ohio)	X(st)	X(s)					X	X	HG				X
21-193-0003	Perry County Horse Park Hazard (Perry)	Xt					X(s)							X
21-195-0002	101 N. Mayo Trail, DOT Office Pikeville (Pike)	X(ct)					X(s)							
21-213-0004	KY DOT Garage, KY 1008 Franklin (Simpson)						X(s)							
TBA	Salem Elementary Russell Springs (Russell)							X						
	TOTAL	7	4	0	0	0	4	5	2	2	6	1	1	3

(c) Collocated Monitor
(s) Special Purpose Monitor
(t) Continuous PM Monitor

(Rev.6/30/09)

CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Grayson Lake
AQS Site ID: 21-043-0500
Location: Camp Webb at Grayson Lake Grayson Lake, KY 41143
County: Carter
GPS Coordinates: 38.238333, -82.988333
Date Established: May 13, 1981
Inspection Date: October 24, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter in a fenced area located in a remote section of Camp Webb in Grayson, Kentucky. The nearest road is a service road to the site. The most recent site inspection was conducted on October 24, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to determine background levels of $PM_{2.5}$; to provide ozone data upwind of the Ashland area; to measure background levels of Mercury in ambient air and in precipitation; and to measure rural concentrations of a sub-group of air toxics for use in national assessment.

Monitors:

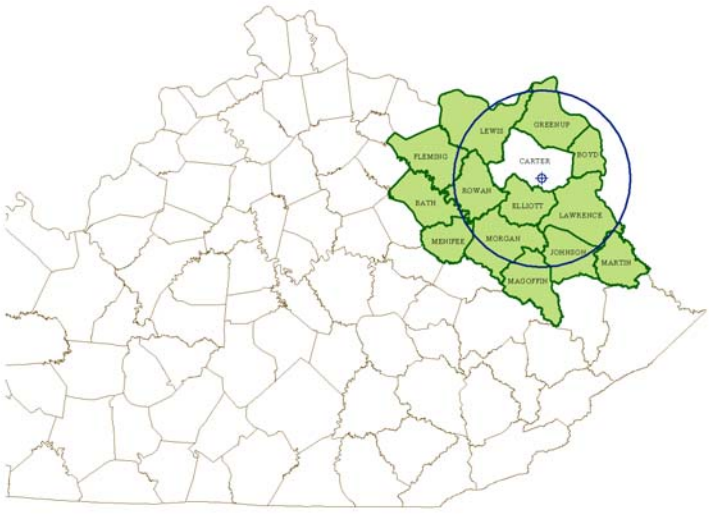
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4	SPM AQI	UV photometry	Continuously March 1 – October 31
FEM $PM_{2.5}$	3.2	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Speciation	4.5	SLAMS	Thermal optical, ion chromatography, and X-ray fluorescence	24-hours every sixth day
FRM PM_{10}	3	SLAMS	Gravimetric	24-hours every sixth day
-Collocated PM_{10}	3	SLAMS	Gravimetric	24-hours every sixth day
-Metals PM_{10}		SPM	Determined from the PM_{10} sample using EPA method IO 3.5	Same as PM_{10}
Mercury - ambient	4.2	SPM	Cold vapour atomic fluorescence spectrometry	Continuously

Mercury - Wet deposition	1.5	SPM	Wet deposition collected, analysis of sample by the Environmental Services Laboratory using EPA method 1631, Revision E	Weekly
Wet deposition	1.3	SPM	Wet deposition collected, analysis of sample by the Environmental Services Laboratory	Weekly
Volatile Organics Compound	4	NATTS	EPA method TO-15	24-hours every sixth day
Polycyclic Aromatic Hydrocarbons		NATTS	EPA method TO-13A	24-hours every sixth day
Carbonyls	3.5	NATTS	EPA method TO-11A	24-hours every sixth day
$Chrome_{VI}$	3.5	NATTS	SOP for the Determination of Hexavalent Chromium in Ambient Air Analyzed by Ion Chromatography (IC)	24-hours every sixth day
-Collocated $Chrome_{VI}$	3.5	NATTS	SOP for the Determination of Hexavalent Chromium in Ambient Air Analyzed by Ion Chromatography (IC)	24-hours every twelfth day
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, relative humidity, temperature, solar radiation and rain gauge	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents background levels on an urban scale for particulates and mercury. This site also represents upwind/background levels on an urban scale for ozone and population exposure on an urban scale for wet deposition.

Urban Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Paducah – Cairo Interstate (072)
Site Name: TVA Calvert City
AQS Site ID: 21-157-0014
Location: Ballpark Road, Calvert City, KY 42029
County: Marshall
GPS Coordinates: 37.024200, -88.195100
Date Established: January 1, 2005
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is an air toxics monitor location off Ballpark Road in Calvert City, Kentucky. The sample inlet is 2 meters above ground level. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition.

Monitoring Objective:
The monitoring objectives are to determine if toxic air pollutants are present and to quantify them.

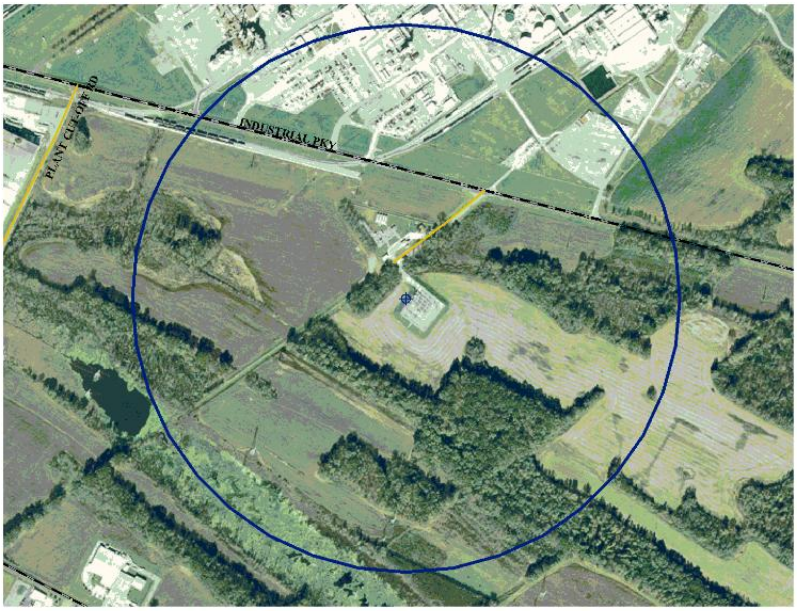
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Volatile Organic Compounds	2	SPM	EPA method TO-15	24-hours every sixth day
- Collocated Volatile Organic Compounds	2	SPM	EPA method TO-15	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents source oriented exposure on a middle scale.

Middle Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Paducah – Cairo Interstate (072)
Site Name: Atmos Calvert City
AQS Site ID: 21-157-0016
Location: KY95, Calvert City, KY 42029
County: Marshall
GPS Coordinates: 37.023100, -88.211500
Date Established: January 1, 2005
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is an air toxics monitor location off KY95 in Calvert City, Kentucky. The sample inlet is 2 meters above ground level. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample inlet and monitor were found to be in good condition.

Monitoring Objective:
The monitoring objectives are to determine if toxic air pollutants are present and to quantify them.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Volatile Organic Compounds	1.9	SPM	EPA method TO-15	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents source oriented exposure on a neighborhood scale.

Neighborhood Scale

CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Paducah – Cairo Interstate (072)
Site Name: Calvert City Elementary
AQS Site ID: 21-157-0018
Location: Calvert City Elementary, 623 5th Avenue, Calvert City, KY 42029
County: Marshall
GPS Coordinates: 37.026916, -88.343944
Date Established: May 1, 2005
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Calvert City Elementary in Calvert City, Kentucky. The sample inlets are 80 feet from the nearest road. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

Monitoring Objective:
The monitoring objectives are to determine if toxic air pollutants are present and to quantify them; and to provide meteorological data for air toxics analysis.

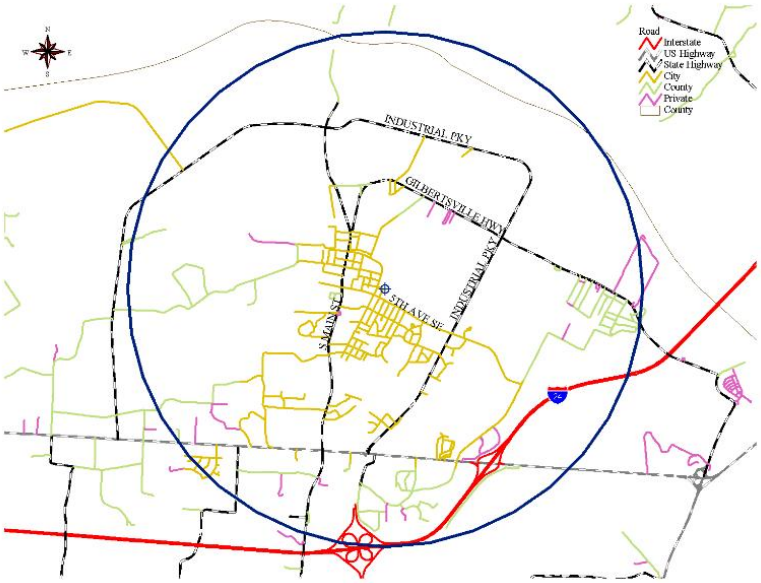
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM PM_{10}	4.5	SPM	Gravimetric	24-hours every sixth day
- Metals PM_{10}		SPM	Determined from the PM_{10} sample using EPA method IO 3.5	Same as PM_{10}
Volatile Organic Compounds	4.4	SPM	EPA method TO-15	24-hours every sixth day
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale.

Neighborhood Scale



Calvert City Air Toxics Network

CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Paducah – Cairo Interstate (072)
Site Name: Lazy Daz
AQS Site ID: 21-157-0019
Location: 4237 Gilbertsville Highway, Calvert City, KY 42029
County: Marshall
GPS Coordinates: 37.03718, -88.33411
Date Established: September 15, 2007
Inspection Date: December 18, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is solar powered, battery charged, air toxics monitor located on the Brady property of the Lazy Daz mobile home park, in Calvert City, Kentucky. The sample inlet is 154 meters from the nearest road. The most recent site inspection was conducted on December 18, 2008. Upon inspection, the sample inlet and monitor were found to be in good condition.

Monitoring Objective:
The monitoring objectives are to determine if toxic air pollutants are present and to quantify them.

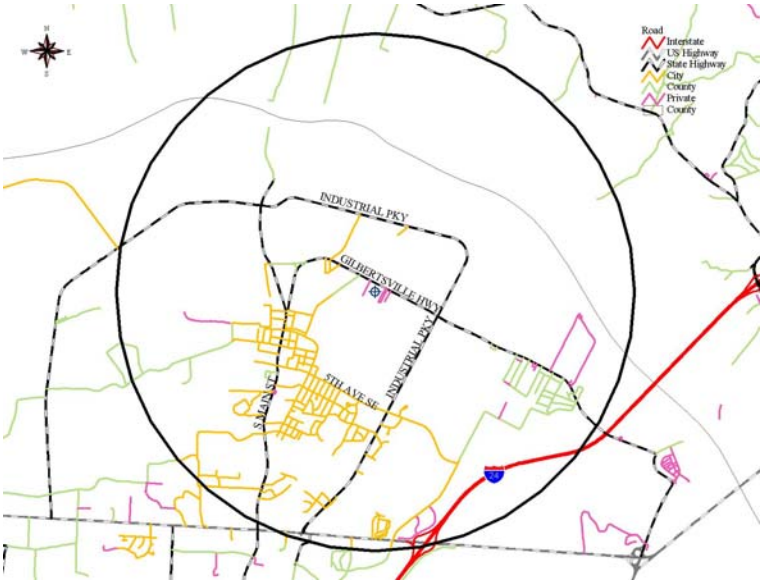
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Volatile Organic Compounds	2	SPM	EPA method TO-15	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents source oriented exposure on a neighborhood scale.

Neighborhood Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Echols
AQS Site ID: 21-183-0032
Location: Keytown Road, Echols, KY 42320
County: Ohio
GPS Coordinates: 37.319725, -86.956097
Date Established: February 1, 2005
Inspection Date: December 17, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on farmland off Keytown Road near the intersection with Pond Church Road in Echols, Kentucky. The sample inlets are 100 feet from the nearest road. The most recent site inspection was conducted on December 17, 2008. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D and E.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

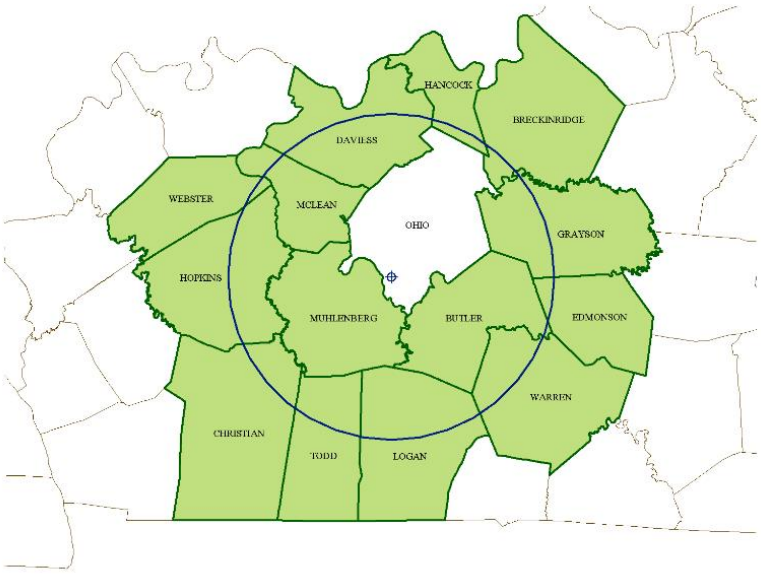
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM PM_{10}	2.2	SPM	Gravimetric	24-hours every sixth day
-Metals PM_{10}		SPM	Determined from the PM_{10} sample using EPA method IO 3.5	Same as PM_{10}
FEM $PM_{2.5}$	2.2	SPM	Gravimetric	24-hours every third day
PM2.5 TEOM	2.7	SPM	Tapered element oscillating microbalance, gravimetric	Continuously
Mercury - ambient	2.5	SPM	Cold vapour atomic fluorescence spectrometry	Continuously
Mercury - Wet deposition	1.3	SPM	Wet deposition collected, analysis of sample by the Environmental Services Laboratory	Weekly
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, relative humidity, temperature and rain gauge	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents source oriented exposure on an urban scale.

Urban Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Appalachian Intrastate (101)
Site Name: Hazard
AQS Site ID: 21-193-0003
Location: Perry County Horse Park, Hazard, KY 41701
County: Perry
GPS Coordinates: 37.283056, -83.220278
Date Established: April 1, 2000
Inspection Date: November 26, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Perry County Horse Park in Hazard, Kentucky. The sample inlets are 65 feet from the nearest road. The most recent site inspection was conducted on November 26, 2008. Upon inspection the sample lines and monitors were found to be in good condition. This site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for ozone; and to provide pollutant levels for daily index reporting.

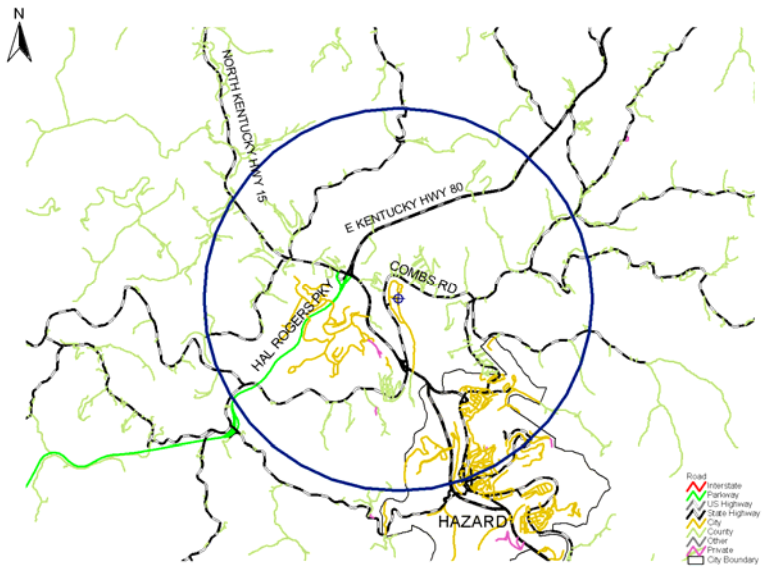
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.5	SPM EPISODE AQI	UV photometry	Continuously March 1 – October 31
PM2.5 TEOM	5.2	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, relative humidity, barometric pressure, and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale.

Neighborhood Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Appalachian Intrastate (101)
Site Name: Pikeville Primary
AQS Site ID: 21-195-0002
Location: DOT District Office, 101 North Mayo Trail, Pikeville, KY 41501
County: Pike
GPS Coordinates: 37.482778, -82.535278
Date Established: May 1, 1994
Inspection Date: November 26, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located behind the DOT District Office building at 101 North Mayo Trail in Pikeville, KY. The sample inlets are 116 feet from the nearest road. The most recent site inspection was conducted on November 26, 2008. Upon inspection the sample lines and monitors were found to be in good condition. This site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards, and to provide pollutant levels for daily index reporting.

Monitors:

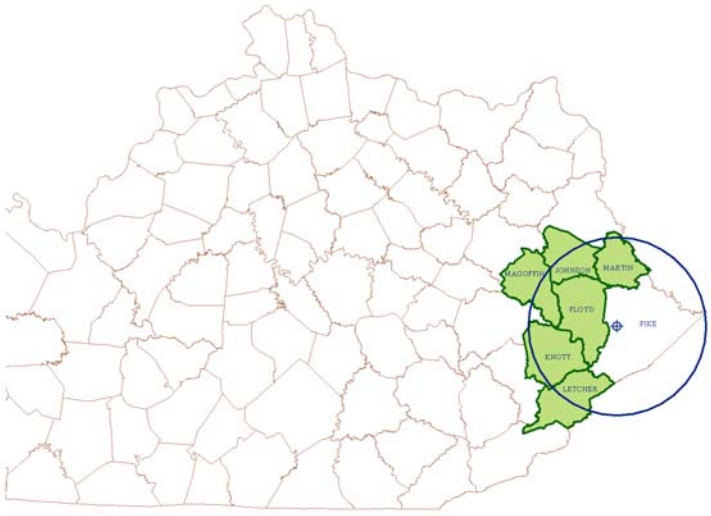
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.6	SPM AQI	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.9	SLAMS	Gravimetric	24-hours every sixth day
- Collocated FRM $PM_{2.5}$	4.9	SLAMS	Gravimetric	24-hours every sixth day
PM2.5 TEOM	4.9	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale for particulates. This site also represents population exposure on an urban scale for ozone.

Particulate Neighborhood Scale

Ozone Urban Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: South Central Kentucky Intrastate (105)
Site Name: Franklin
AQS Site ID: 21-213-0004
Location: DOT Garage, KY 1008, Franklin, KY 42134
County: Simpson
GPS Coordinates: 38.219361, -84.838500
Date Established: June 19, 1991
Inspection Date: December 4, 2008
Inspection By: Andrea P. Keatley
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the DOT Garage on KY1008 in Franklin, Kentucky. The sample inlet is 200 feet from the nearest road. The most recent site inspection was conducted on December 4, 2008. Upon inspection, the sample line and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to measure ozone levels upwind of Bowling Green; and to provide data on interstate ozone transport.

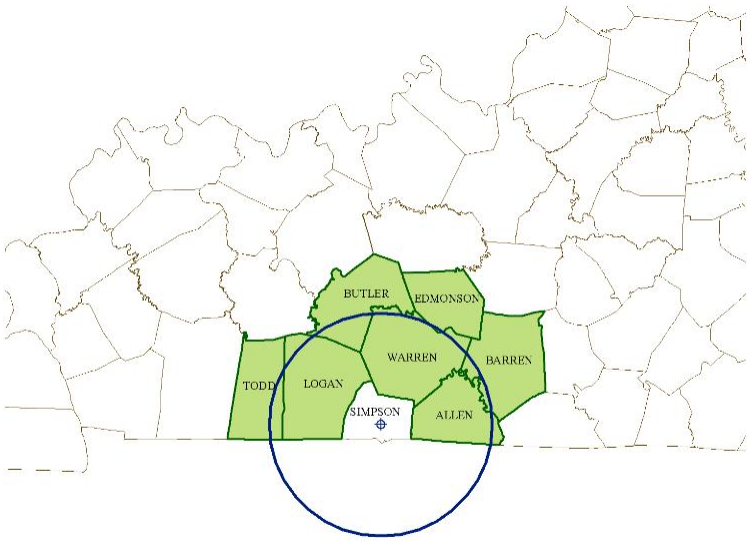
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.3	SPM AQI	UV photometry	Continuously March 1 – October 31
Meteorological	7.5	Other	AQM grade instruments for wind speed, wind direction, relative humidity, barometric pressure, and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on an urban scale.

Urban Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: South Central Kentucky Intrastate (105)
Site Name: Salem Elementary
AQS Site ID: TBA
Location: TBA
County: Russell
GPS Coordinates:
Date Established: January 1, 2010
Inspection Date:
Inspection By:
Site Approval Status:

Superior Battery, located in Russell Springs, Kentucky, was identified as a lead source emitting over 1 tons per year of actual reported emissions in 2006. In accordance with 40 CFR Part 58 Appendix D, a lead source monitoring site will be located at the Salem Elementary School in Russell Springs, Kentucky. The location of this source-oriented lead monitor was determined through the use of AERMOD modeling analysis.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM Lead		SLAMS	Gravimetric	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures will be implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents maximum concentrations, from a source, on a middle scale for lead.

APPENDIX A
West Jefferson County Air Toxics Monitoring Stations
Volatile Organics

AIRS ID	Established	Method	Location	Purpose
21-111-1041	1999	TO-15	4201 Algonquin Parkway	Maximum Impact
21-111-0054	1999	TO-15	4211 Campground Road	Maximum Impact
21-111-0058	1999	TO-15	Farnsley Middle School 3400 Lees Lane	Neighborhood Exposure
21-111-0060	1999	TO-15	Chickasaw Park	Neighborhood Exposure
21-111-0062	1999	TO-15	Cane Run Elementary	Neighborhood Exposure
21-111-0067	2009	TO-15	Cannons Lane	Neighborhood Exposure

APPENDIX B

Louisville Metro Air Pollution Control District's

Ambient Air Monitoring Work Plan
For
National Core (NCore) Monitoring Station

Ambient Air Monitoring Work Plan
For
National Core (NCore) Monitoring Station

CBSA
Louisville-Jefferson County
KY-IN MSA

Louisville Metro Air Pollution Control District
850 Barret Avenue
Louisville, KY 40204

National Core (NCore) Multi-pollutant Monitoring Stations:

In October 2006 the United States Environmental Protection Agency (EPA) issued final amendments to the ambient air monitoring regulations for criteria pollutants. These amendments are codified in 40 CFR parts 53 and 58. The purpose of the amendments was to enhance ambient air quality monitoring to better serve current and future air quality needs. One of the most significant changes in the regulations was the requirement to establish National Core (NCore) multi-pollutant monitoring stations. These stations will provide data on several pollutants at lower detection limits and replace the National Air Monitoring Station (NAMS) networks that have existed for several years. The final network plan must be submitted to EPA by July 1, 2009, and the stations must be operational by January 1, 2011.

In 2007, EPA provided funding to the Louisville Metro Air Pollution Control District (LMAPCD) to begin the process of establishing an NCore station in Jefferson County. In January 2008, the Kentucky Division for Air Quality delegated the responsibility for establishing and operating an NCore station to the District. Upon evaluating the existing network, historical data, census data, meteorology, and topography the District recommends that the SLAMS site located at 2730 Cannons Lane be designated as the NCore site for the Louisville-Jefferson County CBSA.

Monitoring Objectives:

The NCore Network addresses the following monitoring objectives:

- timely reporting of data to the public through AIRNow, air quality forecasting, and other public reporting mechanisms
- support development of emission strategies through air quality model evaluation and other observational methods
- accountability of emission strategy progress through tracking long-term trends of criteria and non-criteria pollutants and their precursors
- support long-term health assessments that contribute to ongoing reviews of the National Ambient Air Quality Standards (NAAQS)
- compliance through establishing nonattainment/attainment areas by comparison with the NAAQS
- support multiple disciplines of scientific research, including public health, atmospheric and ecological

Site Configuration:

The NCore sites must measure at a minimum $PM_{2.5}$ particle mass using continuous and integrated/filter based samplers, speciated $PM_{2.5}$, $PM_{10-2.5}$ (PM_{10c}) particle mass, speciated $PM_{10-2.5}$ particle mass, O_3, SO_2, CO, NO/NO_y, wind speed, wind direction, relative humidity, and ambient temperature. Table 1 provides a list of the sampling equipment and methodology currently used and proposed for the Cannons Lane NCore site

Table 1: Monitors/Samplers

Monitor Type	Designations	Analysis Method	Frequency of Sampling	Startup Date
Carbon Monoxide (CO)	NCore AQI	Automated Reference Method* utilizing trace level non-dispersive infrared analysis.	Continuously	01/01/2010
Nitrogen Oxide (NO_x)	NCore AQI	Automated Reference Method utilizing chemiluminescence analysis.	Continuously	01/01/2010
Ozone (O_3)	NCore AQI	Automated Equivalent Method utilizing UV photometry analysis.	Continuously	01/01/2010
Sulfur Dioxide (SO_2)	NCore AQI	Automated Equivalent Method utilizing trace level UV fluorescence analysis	Continuously	01/01/2010
Total Reactive Nitrogen (NO/NO_y)	NCore	Automated method utilizing trace level chemiluminescence analysis.	Continuously	01/01/2011
$PM_{2.5}$ Filter	NCore	Manual Reference Method utilizing gravimetric analysis.	1/3 days	01/01/2009
$PM_{2.5}$ Continuous	NCore AQI	Automated Equivalent Method* utilizing Tapered Element Oscillating Microbalance/gravimetric analysis	Continuously	01/01/2009
$PM_{2.5}$ Speciation	NCore	Multi-species manual collection method utilizing thermal optical, ion chromatography, gravimetric, and X-ray fluorescence analyses.	1/6 days 1/3 days	01/01/2009 01/01/2011
PM_{10c} Filter	NCore	Manual Reference Method* PM_{10c} utilizing differential gravimetric analysis.	1/3 days	01/01/2009
$PM_{10-2.5}$ Speciation	NCore	Method pending	1/3 days	Requirement under review
Meteorological	NCore	Air Quality Measurements approved instrumentation for wind speed, wind direction, humidity, temperature, rainfall, and solar radiation	Continuously	07/01/2009
Lead	SLAMS	Manual Reference Method TSP Sampler, Analytical method to be determined.	1/6	01/01/2011
Radiation	RadNet	RadNet fixed station air monitor, manual and automated methods	Continuously + 2 weekly filters	01/01/2009
Volatile Organic Compounds	SPM	EPA Compendium Method TO-15 utilizing Summa® passivated canisters	1/12	02/10/2009

* Pending EPA designation

Quality Assurance Status:

All Quality Assurance procedures shall be implemented in accordance with 40 CFR 58, Appendix A. The District's current Quality Assurance Project Plan covers $PM_{2.5}$, Ozone, NOx, SO_2, CO, $PM_{2.5}$ Speciation, and meteorological measurements. The Quality Assurance Project Plan will be revised to include trace level measurements and lead. Standard operating procedures manuals will be adopted or developed for new instrumentation.

Area of Representativeness:

40 CFR Part 58 Appendix D provides design criteria for ambient air monitoring. The monitoring objective for the NCore site is to produce data that represents a fairly large area and therefore the spatial scale of the site is important. The spatial scale defines the physical dimensions of the air parcel nearest to a monitoring site throughout which actual pollutant concentrations are reasonably similar. It is determined by the characteristics of the area surrounding the air monitoring site and the site's distance from nearby air pollution sources such as roadways, factories, etc. In the case of urban NCore the spatial scales to be used are neighborhood and urban. Table 2 shows the area of representativeness for each pollutant for the Cannons Lane site.

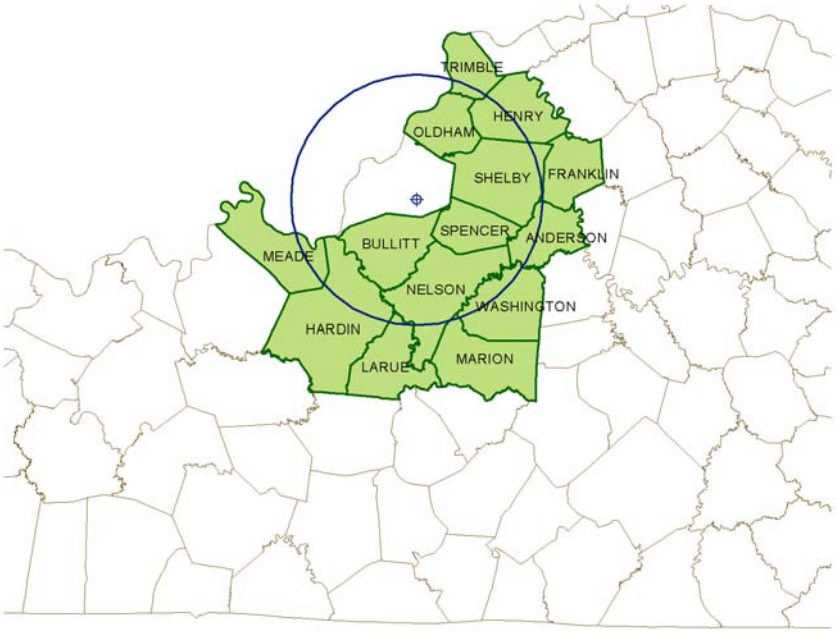
Table 2: Spatial Scales for Each Pollutant

Pollutant	Spatial Scale	Comments
Ozone	Neighborhood and Urban Scale	Use 10 km
NO_x /NO_y	Neighborhood and Urban Scale	Use 10 km
Carbon Monoxide	Neighborhood Scale	There is no Urban scale for CO
SO_2	Neighborhood Scale	There is no Urban scale for SO_2
PM_{10}/$PM_{2.5}$/Lead	Urban	
Radiation	Urban	
VOCs	Neighborhood	

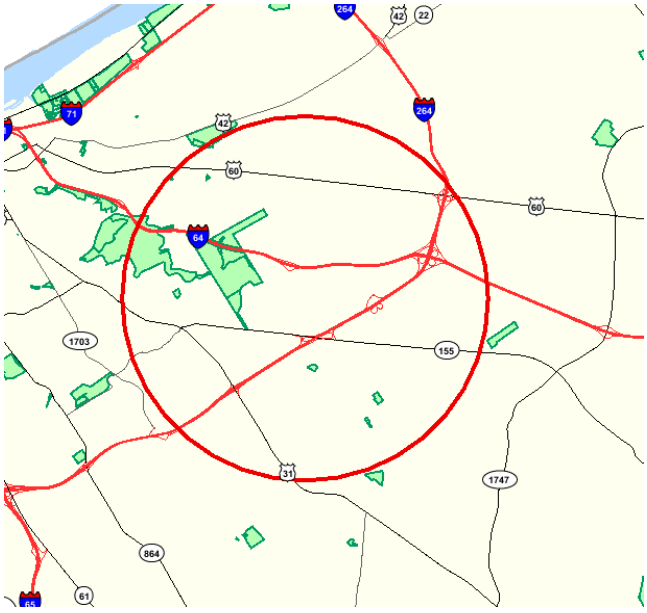
For neighborhood scale the area covered is up to a 4 km radius around the air monitoring site. This area is a mix of commercial, light industrial, and residential. Approximately 20% of the total population for Jefferson County lives within a 4 km radius of the site. This scale also includes 36 schools, 3 hospitals, 6 parks and 3 large shopping venues.

Urban scale is 4 km up to 50 km. 50 km would cover the entire MSA and overlap the current monitoring network. Dropping the scale down to 10 km covers most of the urban core and a portion of the MSA currently not covered by air monitoring. On a 10 km scale the land use varies from light to heavy industrial, commercial and dense residential. Approximately 50% of the total population for Jefferson County lives within 10 km of the site.

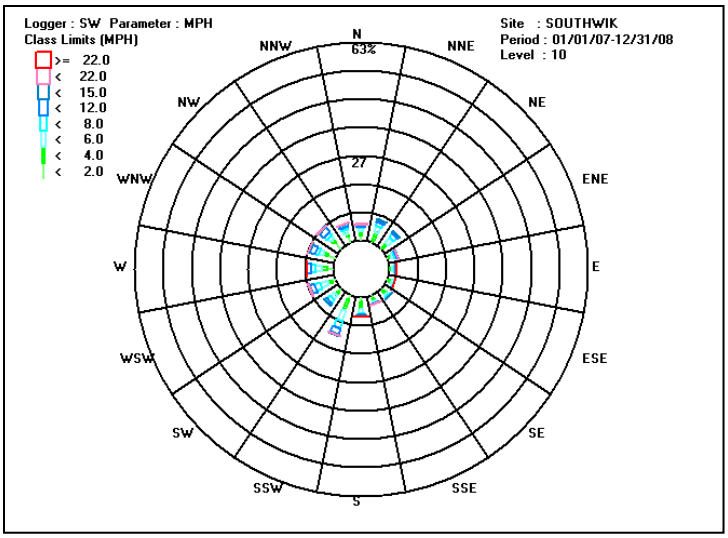
Ozone, $PM_{2.5}$, PM_{10}, and NO_x urban scale (50 km)

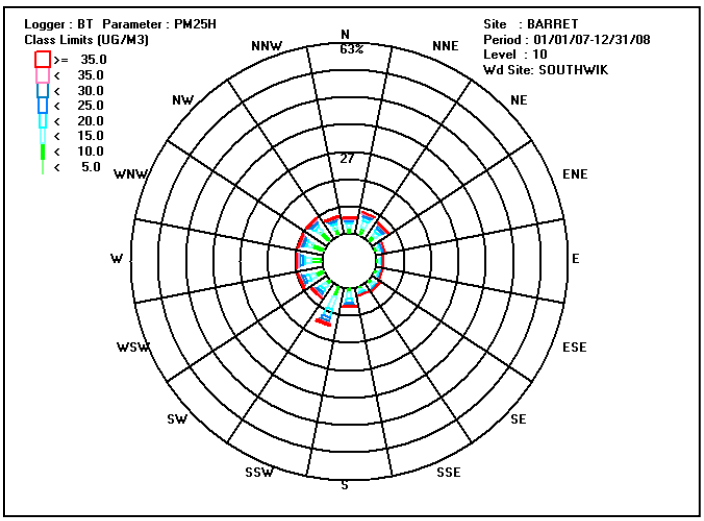


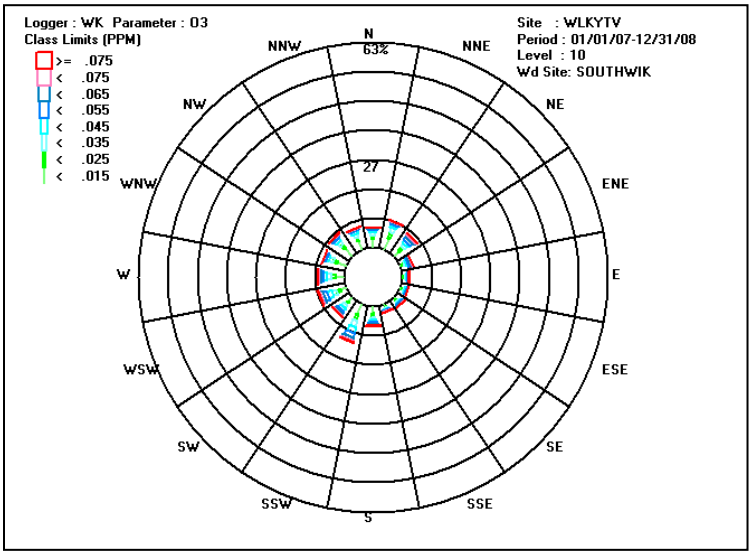
CO neighborhood scale (4 km)



The proposed NCore site is located east of the urban core and north east of the heavier industrialized areas of the metro area. The wind rose (Parameter MPH) indicates the prevailing wind directions while the pollution roses show the distributions of $PM_{2.5}$ and ozone readings within the 16 quadrants. The placement of the NCore site east of the urban core provides the best location for measuring transport and secondary pollutant formation from that area. The placement of the NCore site downwind of the more industrialized areas compliments the existing network which, is primarily designed to measure maximum concentration on a neighborhood scale. An added bonus would be measurement of transport from the NNE and NE quadrants which although monitored by sites in Southern Indiana, are not effectively addressed by sites located in Kentucky.

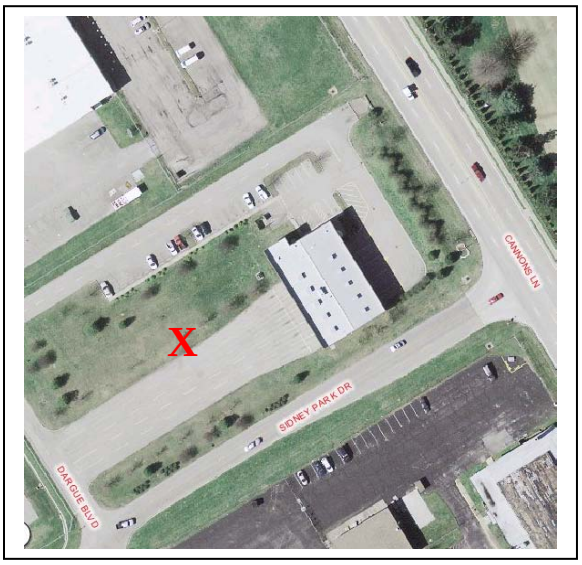






Site Description and Spacing:

401 KAR 50:20 Air Quality Control Region: Louisville Interstate (078)
CBSA: Louisville-Jefferson County, KY-IN MSA
Site Name: Cannons Lane
AQS ID: 21-111-0067
Location: 2730 Cannons Lane
County: Jefferson
GPS Coordinates: 38.228833, -85.654403
Date Established: January 1, 2009
Inspection Dates: Initial site inspection by KyDAQ April 17, 2008
Site inspection by EPA December 9, 2008
Inspections By: Andrea P. Keatley, Kentucky Division for Air Quality
Richard Guillot and Jerry Burger, EPA Region 4 SESD
Site Approval Status: EPA approval as SLAMS December 22, 2008
NCore approval pending



The station is located on property leased by LMAPCD. The property was used as a Vehicle Emissions Testing (VET) center but is now used primarily for storage. The location is in the NE quadrant of Jefferson County and is approximately 9 km from the urban core of Metro Louisville.

NCore and $PM_{2.5}$ SLAMS Siting Criteria

Appendix E to 40 CFR Part 58-*Probe and Monitoring Path Siting Criteria for Ambient Air Quality Monitoring* contains specific location criteria applicable to NCore and SLAMS siting. The following measurements and data were obtained for evaluation of compliance with the criteria.

1. Horizontal Placement of Sampling Probes:
The gaseous instruments will be placed in a 10'w x 16'l x 8'h air monitoring shelter to be located approximately 45 meters behind the (VET) building. The

sample inlet(s) for CO, SO_2, NO_x, and O_3 will be approximately 2 meters above the roof of the shelter and 4.5 meters above ground level. The sample inlet probe for the NOy sampler will be placed on a 10 meter nested tower.

The manual particulate samplers are on a wooden deck near the sampling shelter. The height of the inlets of the particulate samplers varies between 2-3 meters. Separation of the samplers on the deck varies from 1-2 meters depending on the flow rate of the samplers.

The continuous particulate sampler is currently on the deck but will be moved to the roof of the air monitoring shelter once it is installed. The inlet will be 2 meters above the roof and 4.5 meters above ground. The control unit will be located inside the temperature controlled shelter.

2. Spacing from Obstructions:

VET Office/garage (h=7.5 meters): 45 meters
Large Pine to the North West (estimated h=8 meters): from drip line 20 meters
Small Pine to the North West (estimated h=5 meters): from drip line 14 meters
Deciduous tree to the West (estimated h=5 meters): from drip line 30 meters
Deciduous tree to the East (estimated h=7 meters): from drip line 16 meters
Sampling platform from air monitoring shelter (h=2.5 meters): 5.0 meters
T-Hanger (estimated h=10 meters): 67 meters
Army Reserve Center (estimated h=10 meters): 68 meters
National Guard Complex (estimated h= 10 meters): 76 meters

3. Spacing from Roadways:

Tables E-1, E-2, and Figure E-1 of 40 CFR Part 58 Appendix E list the minimum distances from roadways a monitoring probe needs to be based on the average daily traffic (ADT) counts. Table 3 summarizes the findings and includes the minimum separation distance from roadways for each pollutant. ADT counts were obtained from a traffic count map generated from the Kentucky Transportation Cabinet's website.

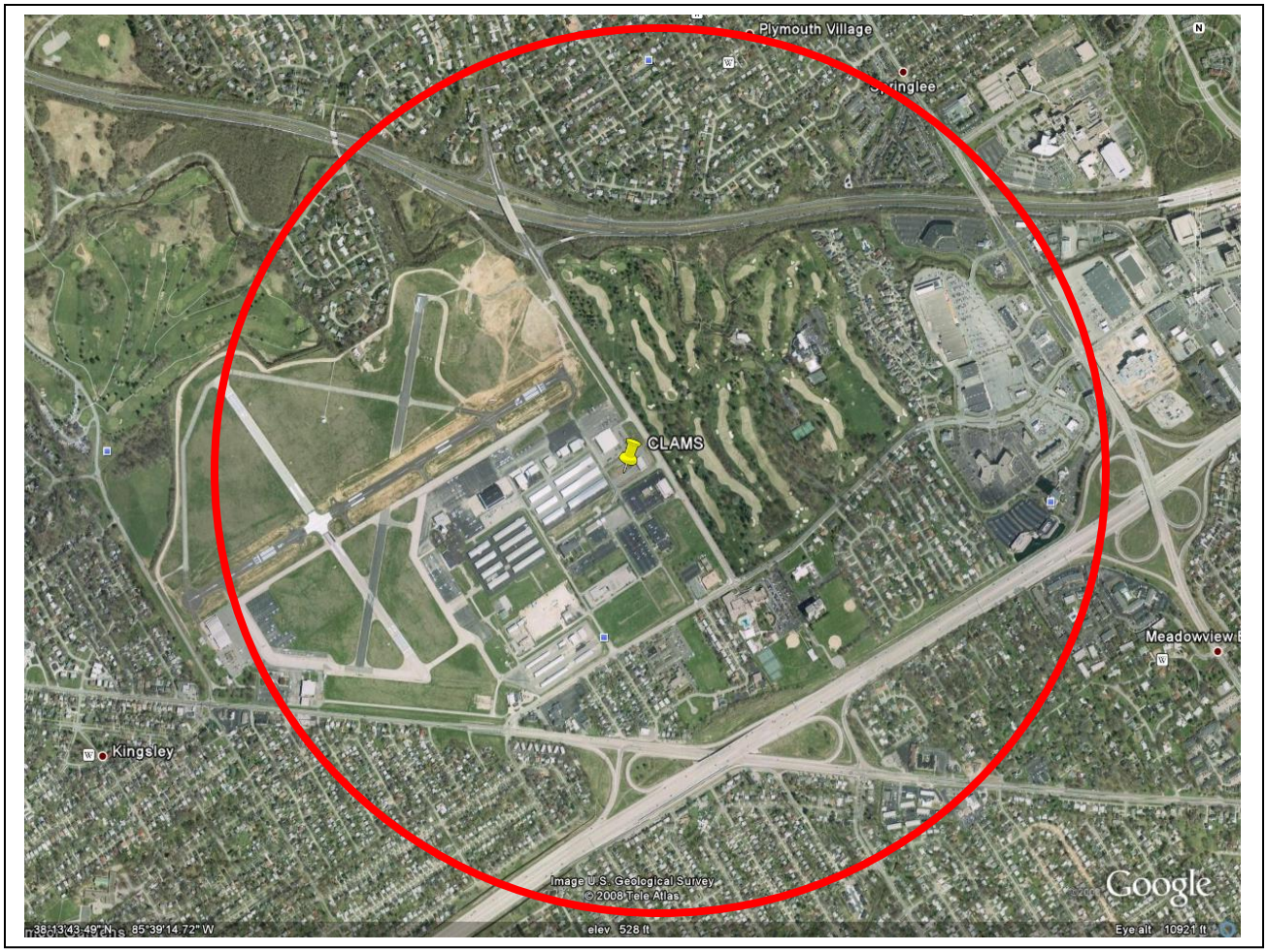
Table 3
Spacing from Roadways Analysis

Roadway	ADT	Distance from site (meters)	Minimum Distance Required (meters)			
			Ozone Table E-1	NO/NO_y Table E-1	CO Table E-2	PM Figure E-1
Cannons Lane	18,709 (2006)	104	40	30	45	80
Dutchmans Lane	16,605 (2007)	441	40	30	45	80
I-64	79,332 (2008)	732	100	100	150	160
I-264	153,890 (2007)	833	250	250	150	160
Sidney Park Drive	<1000 (estimated)	32	10	10	10	10
Dargue Blvd	<1000 (estimated)	45	10	10	10	10

4. Spacing from Minor Sources:

The closest source to the site is the Bowman Field Airport. The airport is a general aviation field with the majority of the air traffic being privately owned piston engine small aircraft. For FY 2008 the average take off and landings were reported as 52,712 or approximately 145 per day.

The main runway is approximately 854 meters from the site.
The main terminal is approximately 1372 meters from the site.



Cannons Lane (CLAMS) 1 km radius

N

W E

S

Direction	Description	Distance from Site
North	Army Reserve Center (offices, storage, hangers)	68 meters
North East	Parking lot for VET center (25 spaces)	20 meters
East	Cannons Lane VET center (office and storage)	45 meters
South East	National Guard Complex & Sidney Park Drive	76 meters
South	Intersection of Sydney Park Drive and Dargue Blvd	76 meters
South west	View toward Dargue Blvd (paved area was VET stacking lane)	45 meters
West	Airport rental T-Hangers	67 meters
North West	Airport rental T-Hangers	72 meters

Cannons Lane Ambient Air Monitoring Station

Site Details:

The photograph above was taken looking toward the NE and shows the sampling platform which is 8'w x 14'l and 18"h. The sample inlets are between 2-3 meters above the ground. The platform supports the $PM_{2.5}$ FRM, the PM_{10c}, $PM_{2.5}$ Speciation, URG Carbon, and the RadNet sampler. It also has room for lead sampling if needed and room for the PEP audit equipment. Electrical service to the platform is 100 amps with 5 (20 amp GFCI) outlets strategically placed on the platform to provide power to the instruments.

The air monitoring shelter will be located on the concrete pad in front of the site and approximately 6 meters from the sampling platform. The shelter will be 10'w x 16'l x 8'h. The roof of the shelter will be flat to support the sample inlets for the continuous particulate sampler(s) and has additional room for other samplers if the need arises. The 10 meter meteorological tower will be next to the shelter and will be of the "nested" type to insure that the NOy convertor is kept vertical and to ease servicing and calibration of the meteorological instruments. The shelter will be wired for 200 amp service and have internet and telephone connections. To maintain temperatures between 30-40 º C the shelter will have a 24,000 BTU heat pump with a digital programmable thermostat. The shelter insulation will be a minimum R-18. Once the shelter has been installed the chain link fence will be extended to enclose the entire site.

APPENDIX C

Source Impact Lead Monitoring
Waiver Requests
For
Kentucky Division for Air Quality (C-2)
And
Louisville Metro Air Pollution Control District (C-75)

AERMOD Modeling Analysis in Support of the Lead NAAQS Waiver Requests for the State of Kentucky

Introduction

On November 12, 2008, the United States Environmental Protection Agency (EPA) strengthened the National Ambient Air Quality Standard (NAAQS) for lead. The revised standard is now set at 0.15 µg/m^3 for the primary (health-based) and secondary (welfare-based) standards. In conjunction with the revision of the lead NAAQS, the EPA promulgated new network design criteria, which can be found in 40 CFR Part 58, Appendix D, paragraph 4.5. Source-oriented monitoring is required for those facilities which emit 1.0 ton per year (tpy) or more of lead in the air.

The Kentucky Division for Air Quality (Division) received formal notification from EPA Region 4 in April 2009 of the sources within the Commonwealth that were subject to lead monitoring per the revised regulations. Those seven facilities are listed in this document as ***Appendix A: Kentucky Facilities with Lead Emissions over 1.0 TPY***. The facilities include: American Electric Power – Big Sandy Plant (Big Sandy), in Louisa, KY; Calgon Carbon in Catlettsburg, KY; Enersys in Richmond, KY; Newpage in Wickliffe, KY; North American Stainless (NAS) in Ghent, KY; Superior Battery in Russell Springs, KY; and Tennessee Valley Authority (TVA) Shawnee Fossil Plant in West Paducah, KY.

Section 4.5(ii) of Appendix D to 40 CFR 58 contains waiver provision for source-oriented lead monitoring, if a state or local agency can demonstrate that the lead source will not contribute to a maximum lead concentration in ambient air in excess of one-half of the Pb NAAQS (i.e., 0.075 µg/m^3). Consequently, the Division has modeled the facilities to determine whether or not to pursue waivers. Additionally, recent Kentucky Emissions Inventory data has been reviewed for this purpose.

Emissions Inventory Data

The Division's Emissions Inventory Section (EIS) has compiled calculations for 2006-2008 data for those seven facilities listed in the aforementioned ***Appendix A: Kentucky Facilities with Lead Emissions over 1.0 TPY.***

Emissions Inventory Reports for all seven facilities are included with this document on a compact disc (CD) for review. The CD (labeled KY DAQ EIS Data) also contains Kentucky Emissions Inventory data files for 2006, 2007, and 2008, as well as permits for the facilities in question. Table 1 shows the results of the recent EIS calculations.

Table 1. Kentucky Emissions Inventory Data

Facility Name	Location	2006 Actual Emissions (tpy)	2007 Actual Emissions (tpy)	2008 Actual Emissions (tpy)
Big Sandy	Louisa	2.37	0.61	Not complete
Calgon Carbon	Catlettsburg	6.01	6.06	6.29
Enersys	Richmond	0.11	2.16	1.45
Newpage	Wickliffe	7.39	6.28	Not complete
North American Stainless	Ghent	0.98	0.59	0.65
Superior Battery	Russell Springs	1.35	0.67	0.61
TVA Shawnee	West Paducah	8.33	8.42	8.57

Selection Criteria for the Modeled Facilities

Pursuant to 40 CFR Part 58, Appendix D, paragraph 4.5(a), monitoring agencies must use the most recent National Emissions Inventory (NEI) or other scientifically justifiable data to determine if a facility emits more than 1 tpy of lead. The Division, at the direction of EPA Region 4, chose to use both state emissions inventory data and Toxic Release Inventory (TRI) data from 2006 and 2007. 40 CFR Part 58 Appendix D 4.5 (ii) states: "The Regional Administrator may waive the requirement in paragraph 4.5(a) for monitoring near lead (Pb) sources if the State or, where appropriate, local agency can demonstrate the Pb source will not contribute to a maximum Pb concentration in ambient air *in excess of* 50% of the NAAQS (based on historical monitoring data, modeling, or other means)." The lead NAAQS is based on a 3-month rolling average.

Model Parameters

Urban versus Rural Determination

The facilities modeled in this analysis were all modeled as rural. The rural setting was chosen based on the population density procedure as stated in Section 7.2.3(d) of 40 CFR 51, Appendix W. In addition, none of the facilities modeled fall into a highly industrialized category as mentioned subsequently in Section 7.2.3(e) of Appendix W.

Meteorological Data

In compliance with the EPA air quality modeling guideline found in Section 8.3 of 40 CFR Part 51, Appendix W, the modeling performed for each facility relied on five years of consecutive meteorological data taken from the most representative surface and upper air meteorological stations. A summary of general meteorological modeling data can be found in Table 2. The meteorological data

years were chosen in part due to their availability and the completeness of the data. Unfortunately, the funding for more recent data for this particular project, which is in excess of $3,150, was not available. Therefore, the facilities were modeled with meteorological data ranging from 1988 to 1992, or 1989 to 1993, which is free to the public. Data sets deemed complete for the respective five years were chosen.

Table 2. Meteorological Modeling Data

Facility	Met Years	Surface Air Station	Upper Air Station
Big Sandy	1988-1992	Huntington/Tri-State Airport	Huntington/Tri-State Airport
Calgon Carbon	1988-1992	Huntington/Tri-State Airport	Huntington/Tri-State Airport
Enersys	1988-1992	Lexington/Blue-grass Field	Huntington/Tri-State Airport
Newpage	1989-1993	Paducah/WSO Airport	Paducah/WSO Airport
North American Stainless	1988-1992	Covington/ Greater Cincinnati	Dayton/Wright Patterson AFB
Superior Battery	1988-1992	Lexington/Blue-grass Field	Nashville/Int'l Airport
TVA Shawnee Fossil Plant	1989-1993	Paducah/WSO Airport	Paducah/WSO Airport

Representativeness/Surface Characteristics

According to the AERMOD Implementation Modeling Guidelines, the meteorological stations should be representative of the facility. The National Weather Service (NWS) meteorological stations chosen for each facility depended on the facility's location, topography, land use, and surface characteristics in reference to each facility. The surface roughness values at each facility were compared against the surface roughness values of the respective meteorological surface station and modeled separately to determine the difference in surface characteristics between them. In the interest of being conservative towards human health, the surface characteristics which yielded the highest monthly concentration were used in calculating the 3-month rolling average. The surface roughness data (albedo, bowen ratio, and surface roughness values) for each of these facilities and meteorological stations can be found in ***Appendix B: AERSURFACE Tables***. Surface roughness parameters are tabulated in Table 3. In AERSURFACE, the default 1 km radius was chosen, temporal resolution was set to "monthly", 12-30º averaged sectors were used throughout the analysis, and the application site coordinates were set to the facility.

Table 3. AERSURFACE defaults for the Meteorological Stations/Sites Used

Facility	Surface Roughness Radius (km)	Surface Moisture	Temporal Resolution	Number of 30° Sectors
Big Sandy	1.0	Average	Monthly	12
Calgon Carbon	1.0	Average	Monthly	12
Enersys	1.0	Average	Monthly	12
Newpage	1.0	Average	Monthly	12
NAS	1.0	Average	Monthly	12
Superior Battery	1.0	Average	Monthly	12
TVA Shawnee	1.0	Average	Monthly	12

The land use was classified based on the 1992 National Land Cover Data (NLCD 92) which is available from the USGS. The NLCD 92 contains a 21-category land cover classification, which is based on Landsat imagery.

Pollutant Averaging

The pollutant averaging time was set to 1-month. The 1-month average was converted to a 3-month rolling average using the lead post processor, which is available from EPA at http://www.epa.gov/ttn/amtic/pb-monitoring.html.

Building Downwash

Building downwash was not deemed necessary for facilities with very tall stacks, such as those found at coal-fired power plants. The stack heights for both AEP Big Sandy and TVA Shawnee exceed the Good Engineering Practices (GEP) stack heights. In addition, any facility significantly over or under the 0.075 $\mu g/m^3$ lead concentration on a 3-month rolling average did not have the building downwash (BPIP) algorithm applied in the model. Therefore, building downwash was only applied to the modeling for Superior Battery based on preliminary modeling showing a 3-month rolling average concentration at one-half the lead NAAQS.

Lead Emission Sources

The lead sources for each facility are tabulated in ***Appendix C*** of this document. The emission sources are based on the emissions data of the year that triggered the analysis as found in Appendix A.

AEP Big Sandy and TVA Shawnee are both electric utilities. AEP Big Sandy uses 2 pulverized coal (pc) combustors. In the case of TVA Shawnee, 9 pc's and 1 bubbling fluidized bed combustor are used. In addition, both facilities have smaller auxiliary units. Hence, their lead emissions primarily stem from the combustion of coal. Enersys and Superior Battery are both battery manufacturers. Their lead emissions are related to battery plating and manufacture. Calgon Carbon produces activated carbon and carbon-based media. Their primary feedstock is bituminous coal, which is also the source material for their lead emissions. Newpage is a paper producer whose primary lead emission point is their combination boiler. North American Stainless produces stainless steel and their primary lead emissions are from a furnace.

Receptors/Terrain

As stated in Section 8.2.2 of Appendix A to Appendix W of 40 CFR 51, "Receptor sites for refined modeling should be utilized in sufficient detail to estimate the highest concentration and possible violations of a NAAQS or PSD increment. In designing a receptor network, the emphasis should be placed on receptor resolution and location, not total number of receptors. The selection of receptor sites should be a case-by-case determination taking into consideration the topography, the climatology, monitor sites, and the results of the initial screening procedure."

The receptor grid parameters (spacing and number of receptors) were chosen in a way to encompass a majority of the plume as well as the significant impact area (SIA) in which the maximum impact occurs. The receptor grids are optimized to have the maximum concentration occur within a 100x100 meter grid. This is achieved by either expanding a tiered receptor grid or including a separate (uniform Cartesian) grid to cover the maximum impact area.

Digital Elevation Maps (DEM) or National Elevation Data (NED) maps available from the USGS were used for the AERMAP processor for each facility.

Table 4 provides a summary of parameters used in AERMOD, which includes the number and distance between receptors, whether building downwash was used, whether plant boundaries were defined, and what type of terrain data was chosen for the facilities.

Table 4. AERMOD General Summary

Facility	Model	Total Receptors	Receptor Grid Parameters	Building Downwash	Plant Boundaries	Terrain DEM or NED Data
Big Sandy	Airport Model	1604	Distance from Center/Tier Spacing 1000m/100m 5000m/500m 10000m/1000m Plus uniform Cartesian grid 100m x 100m to encompass SIA	No	Yes	NED
	Site Model	1163	Distance from Center/Tier Spacing 1000m/100m 5000m/500m 10000m/1000m	No	Yes	NED
Calgon Carbon	Airport Model	1507	Distance from Center/Tier Spacing 1500m/100m 3500m/500m 8000m/1000m	No	No	NED

	Site Model	1507	Distance from Center/Tier Spacing 1500m/100m 3500m/500m 8000m/1000m	No	No	NED
Enersys	Airport Model	1039	Distance from Center/Tier Spacing 100m/100m 3000m/500m	No	Yes	NED
	Site Model	1039	Distance from Center/Tier Spacing 100m/100m 3000m/500m	No	Yes	NED
NAS	Airport Model	3281	Distance from Center/Tier Spacing 2000m/100m 10000m/500m 15000m/1000m	No	Yes	NED
	Site Model	3281	Distance from Center/Tier Spacing 2000m/100m 10000m/500m 15000m/1000m	No	Yes	NED
NewPage	Airport Model	1594	Distance from Center/Tier Spacing 1000m/100m 5000m/500m 15000m/1000m Plus uniform Cartesian grid 100m x 100m to encompass SIA	No	Yes	NED
	Site Model	1602	Distance from Center/Tier Spacing 1000m/100m 5000m/500m 15000m/1000m Plus uniform Cartesian grid 100m x 100m to encompass SIA	No	Yes	NED
Superior Battery	Airport Model	1410	Distance from Center/Tier Spacing 1500m/100m 3500m/500m 8000m/1000m	Yes	No	NED
	Site Model	1410	Distance from Center/Tier Spacing 1500m/100m 3500m/500m 8000m/1000m	Yes	No	NED
TVA Shawnee	Airport Model	2949	3000m x 3000m Plus uniform Cartesian grid 100m x 100m to encompass SIA	No	Yes	DEM

	Site Model	3556	3000m x 3000m Plus three uniform Cartesian grids: 100m x 100m to encompass SIA 750m x 500m 500m x 1000m	No	Yes	DEM

Non-Default Parameters

The Division used a non-default option in the control pathway. The toxics non-default option was chosen to access the total deposition output. In the source pathway, particulate was selected for gas and particle deposition. Method 2 was selected for handling particle deposition by total particulate mass. Particle inputs for Method 2 consisted of the fine particle fraction equaling 0.75 and the mass mean particle diameter equaling 0.5 microns. These values were selected from Appendix B of the AERMOD Deposition Algorithms - Science Document (Revised Draft) found on EPA's Support Center for Regulatory Air Models (SCRAM) website at http://www.epa.gov/scram001/7thconf/aermod/aer_scid.pdf.

Results

Using the parameters given in this document, the models were run. The results for each facility are tabulated Table 5.

Table 5. 3-Month Rolling Average Concentrations

Facility	Surface Characteristics	One-half Lead NAAQS ($\mu g/m^3$)	3-Month Rolling Average Concentration ($\mu g/m^3$)
Big Sandy Plant	Airport	0.075	0.034
	Site	0.075	0.050
Calgon Carbon	Airport	0.075	0.289
	Site	0.075	0.286
Enersys	Airport	0.075	0.244
	Site	0.075	0.407
Newpage	Airport	0.075	0.004
	Site	0.075	0.015
North American Stainless	Airport	0.075	0.001
	Site	0.075	0.001
Superior Battery	Airport	0.075	0.982
	Site	0.075	1.341
TVA Shawnee Fossil Plant	Airport	0.075	0.001
	Site	0.075	0.000

Upon review, the output concentrations from the models show that Calgon Carbon, Enersys, and Superior Battery substantially surpass the modeled ambient concentration required to receive a waiver and indicate a modeled exceedance of the new lead NAAQS. Data in Table 5 also illustrate that the 3-month rolling averages for AEP Big Sandy, Newpage, TVA Shawnee, and North American Stainless are substantially below one-half the lead NAAQS.

Modeled Plots

Plots of the modeled high 1st high monthly impacts for the facilities can be found in ***Appendix D*** of this document. These figures are contour plots of the ambient lead concentrations as modeled. Please note, the concentration shown in the figures do not represent a 3-month rolling average but instead represent the highest monthly impact for the meteorological years chosen. Receptors are not placed within plant boundaries for the facilities that have defined fence lines. Air within the plant boundary of these facilities are represented as white areas. The facilities without defined physical barriers delineating the property line have receptors within their plant boundaries in accordance with the definition of ambient air found in 40 CFR 50.1(e). These facilities boundaries are depicted as red boundary lines.

Conclusion

As mentioned previously, modeling has demonstrated that a waiver for monitoring lead at AEP Big Sandy, Newpage, TVA Shawnee, and North American Stainless can be requested based upon a maximum 3-month rolling average at or below one-half the lead NAAQS. The Calgon Carbon, Enersys, and Superior Battery facilities emissions have been modeled and shown to exceed one-half the lead NAAQS. Therefore, Calgon Carbon, Enersys, and Superior Battery should be monitored in accordance with 40 CFR Part 58, Appendix D, paragraph 4.5(a).

Additional Information

Data has been complied for each facility and is available on the attached compact disc (CD) labeled *KY DAQ Lead Modeling Data: AERMOD*. Each facility has a designated folder which contains files specific the airport and site models. Each model has three folders: the Post Processor folder, the AERMET folder, and the AERMOD folder. The Post Processor folder contains the 3-Month Processor Output File (.out), Plot File (.plt), and a Post File (.pos). The AERMET folder contains the Profile File (.pfl) for Upper Air, Surface File (.sfc), AERMET Log File (.log), and the AERMET Output File (.out). The AERMOD folder contains the AERMOD Input File (.adi) and the AERMOD Output File (.ado).

Appendix A. Kentucky Facilities with Lead Emissions over 1.0 TPY

Facility	City	State	Lead Emissions (tpy)	Data Source
AMERICAN ELECTRIC POWER - BIG SANDY PLANT	LOUISA	KY	**2.37**	2006 S/L Data
CALGON CARBON	CATLETTSBURG	KY	**6.06**	2007 S/L Data
ENERSYS	RICHMOND	KY	**2.16**	2007 S/L Data
NEWPAGE	WICKLIFFE	KY	**6.28**	2007 S/L Data
NORTH AMERICAN STAINLESS	GHENT	KY	**1.14**	2007 TRI
SUPERIOR BATTERY	RUSSELL SPRINGS	KY	**1.35**	2006 S/L Data
TVA SHAWNEE FOSSIL PLANT	WEST PADUCAH	KY	**8.42**	2007 S/L Data

Appendix B. AERSURFACE Tables

Superior Battery Airport					Superior Battery Site				
Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length	Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length
1	1	0.17	0.79	0.067	1	1	0.17	0.79	0.065
1	2	0.17	0.79	0.035	1	2	0.17	0.79	0.079
1	3	0.17	0.79	0.034	1	3	0.17	0.79	0.051
1	4	0.17	0.79	0.036	1	4	0.17	0.79	0.041
1	5	0.17	0.79	0.062	1	5	0.17	0.79	0.05
1	6	0.17	0.79	0.043	1	6	0.17	0.79	0.052
1	7	0.17	0.79	0.042	1	7	0.17	0.79	0.068
1	8	0.17	0.79	0.038	1	8	0.17	0.79	0.103
1	9	0.17	0.79	0.076	1	9	0.17	0.79	0.095
1	10	0.17	0.79	0.08	1	10	0.17	0.79	0.034
1	11	0.17	0.79	0.057	1	11	0.17	0.79	0.073
1	12	0.17	0.79	0.045	1	12	0.17	0.79	0.055
2	1	0.17	0.79	0.067	2	1	0.17	0.79	0.065
2	2	0.17	0.79	0.035	2	2	0.17	0.79	0.079
2	3	0.17	0.79	0.034	2	3	0.17	0.79	0.051
2	4	0.17	0.79	0.036	2	4	0.17	0.79	0.041
2	5	0.17	0.79	0.062	2	5	0.17	0.79	0.05
2	6	0.17	0.79	0.043	2	6	0.17	0.79	0.052
2	7	0.17	0.79	0.042	2	7	0.17	0.79	0.068
2	8	0.17	0.79	0.038	2	8	0.17	0.79	0.103
2	9	0.17	0.79	0.076	2	9	0.17	0.79	0.095
2	10	0.17	0.79	0.08	2	10	0.17	0.79	0.034
2	11	0.17	0.79	0.057	2	11	0.17	0.79	0.073
2	12	0.17	0.79	0.045	2	12	0.17	0.79	0.055
3	1	0.15	0.41	0.075	3	1	0.15	0.43	0.096

3	2	0.15	0.41	0.046	3	2	0.15	0.43	0.116
3	3	0.15	0.41	0.047	3	3	0.15	0.43	0.076
3	4	0.15	0.41	0.05	3	4	0.15	0.43	0.061
3	5	0.15	0.41	0.089	3	5	0.15	0.43	0.074
3	6	0.15	0.41	0.06	3	6	0.15	0.43	0.073
3	7	0.15	0.41	0.057	3	7	0.15	0.43	0.101
3	8	0.15	0.41	0.048	3	8	0.15	0.43	0.154
3	9	0.15	0.41	0.097	3	9	0.15	0.43	0.144
3	10	0.15	0.41	0.1	3	10	0.15	0.43	0.05
3	11	0.15	0.41	0.068	3	11	0.15	0.43	0.102
3	12	0.15	0.41	0.051	3	12	0.15	0.43	0.084
4	1	0.15	0.41	0.075	4	1	0.15	0.43	0.096
4	2	0.15	0.41	0.046	4	2	0.15	0.43	0.116
4	3	0.15	0.41	0.047	4	3	0.15	0.43	0.076
4	4	0.15	0.41	0.05	4	4	0.15	0.43	0.061
4	5	0.15	0.41	0.089	4	5	0.15	0.43	0.074
4	6	0.15	0.41	0.06	4	6	0.15	0.43	0.073
4	7	0.15	0.41	0.057	4	7	0.15	0.43	0.101
4	8	0.15	0.41	0.048	4	8	0.15	0.43	0.154
4	9	0.15	0.41	0.097	4	9	0.15	0.43	0.144
4	10	0.15	0.41	0.1	4	10	0.15	0.43	0.05
4	11	0.15	0.41	0.068	4	11	0.15	0.43	0.102
4	12	0.15	0.41	0.051	4	12	0.15	0.43	0.084
5	1	0.15	0.41	0.075	5	1	0.15	0.43	0.096
5	2	0.15	0.41	0.046	5	2	0.15	0.43	0.116
5	3	0.15	0.41	0.047	5	3	0.15	0.43	0.076
5	4	0.15	0.41	0.05	5	4	0.15	0.43	0.061
5	5	0.15	0.41	0.089	5	5	0.15	0.43	0.074
5	6	0.15	0.41	0.06	5	6	0.15	0.43	0.073
5	7	0.15	0.41	0.057	5	7	0.15	0.43	0.101
5	8	0.15	0.41	0.048	5	8	0.15	0.43	0.154

5	9	0.15	0.41	0.097	5	9	0.15	0.43	0.144
5	10	0.15	0.41	0.1	5	10	0.15	0.43	0.05
5	11	0.15	0.41	0.068	5	11	0.15	0.43	0.102
5	12	0.15	0.41	0.051	5	12	0.15	0.43	0.084
6	1	0.18	0.5	0.094	6	1	0.18	0.4	0.302
6	2	0.18	0.5	0.117	6	2	0.18	0.4	0.341
6	3	0.18	0.5	0.138	6	3	0.18	0.4	0.269
6	4	0.18	0.5	0.16	6	4	0.18	0.4	0.238
6	5	0.18	0.5	0.242	6	5	0.18	0.4	0.257
6	6	0.18	0.5	0.193	6	6	0.18	0.4	0.257
6	7	0.18	0.5	0.107	6	7	0.18	0.4	0.327
6	8	0.18	0.5	0.077	6	8	0.18	0.4	0.411
6	9	0.18	0.5	0.152	6	9	0.18	0.4	0.403
6	10	0.18	0.5	0.127	6	10	0.18	0.4	0.203
6	11	0.18	0.5	0.076	6	11	0.18	0.4	0.31
6	12	0.18	0.5	0.06	6	12	0.18	0.4	0.288
7	1	0.18	0.5	0.094	7	1	0.18	0.4	0.302
7	2	0.18	0.5	0.117	7	2	0.18	0.4	0.341
7	3	0.18	0.5	0.138	7	3	0.18	0.4	0.269
7	4	0.18	0.5	0.16	7	4	0.18	0.4	0.238
7	5	0.18	0.5	0.242	7	5	0.18	0.4	0.257
7	6	0.18	0.5	0.193	7	6	0.18	0.4	0.257
7	7	0.18	0.5	0.107	7	7	0.18	0.4	0.327
7	8	0.18	0.5	0.077	7	8	0.18	0.4	0.411
7	9	0.18	0.5	0.152	7	9	0.18	0.4	0.403
7	10	0.18	0.5	0.127	7	10	0.18	0.4	0.203
7	11	0.18	0.5	0.076	7	11	0.18	0.4	0.31
7	12	0.18	0.5	0.06	7	12	0.18	0.4	0.288
8	1	0.18	0.5	0.094	8	1	0.18	0.4	0.302
8	2	0.18	0.5	0.117	8	2	0.18	0.4	0.341
8	3	0.18	0.5	0.138	8	3	0.18	0.4	0.269

8	4	0.18	0.5	0.16	8	4	0.18	0.4	0.238
8	5	0.18	0.5	0.242	8	5	0.18	0.4	0.257
8	6	0.18	0.5	0.193	8	6	0.18	0.4	0.257
8	7	0.18	0.5	0.107	8	7	0.18	0.4	0.327
8	8	0.18	0.5	0.077	8	8	0.18	0.4	0.411
8	9	0.18	0.5	0.152	8	9	0.18	0.4	0.403
8	10	0.18	0.5	0.127	8	10	0.18	0.4	0.203
8	11	0.18	0.5	0.076	8	11	0.18	0.4	0.31
8	12	0.18	0.5	0.06	8	12	0.18	0.4	0.288
9	1	0.18	0.79	0.091	9	1	0.18	0.79	0.302
9	2	0.18	0.79	0.114	9	2	0.18	0.79	0.341
9	3	0.18	0.79	0.134	9	3	0.18	0.79	0.269
9	4	0.18	0.79	0.158	9	4	0.18	0.79	0.238
9	5	0.18	0.79	0.239	9	5	0.18	0.79	0.257
9	6	0.18	0.79	0.188	9	6	0.18	0.79	0.257
9	7	0.18	0.79	0.097	9	7	0.18	0.79	0.327
9	8	0.18	0.79	0.069	9	8	0.18	0.79	0.411
9	9	0.18	0.79	0.144	9	9	0.18	0.79	0.403
9	10	0.18	0.79	0.118	9	10	0.18	0.79	0.203
9	11	0.18	0.79	0.071	9	11	0.18	0.79	0.31
9	12	0.18	0.79	0.055	9	12	0.18	0.79	0.288
10	1	0.18	0.79	0.091	10	1	0.18	0.79	0.302
10	2	0.18	0.79	0.114	10	2	0.18	0.79	0.341
10	3	0.18	0.79	0.134	10	3	0.18	0.79	0.269
10	4	0.18	0.79	0.158	10	4	0.18	0.79	0.238
10	5	0.18	0.79	0.239	10	5	0.18	0.79	0.257
10	6	0.18	0.79	0.188	10	6	0.18	0.79	0.257
10	7	0.18	0.79	0.097	10	7	0.18	0.79	0.327
10	8	0.18	0.79	0.069	10	8	0.18	0.79	0.411
10	9	0.18	0.79	0.144	10	9	0.18	0.79	0.403
10	10	0.18	0.79	0.118	10	10	0.18	0.79	0.203

10	11	0.18	0.79	0.071	10	11	0.18	0.79	0.31
10	12	0.18	0.79	0.055	10	12	0.18	0.79	0.288
11	1	0.18	0.79	0.091	11	1	0.18	0.79	0.302
11	2	0.18	0.79	0.114	11	2	0.18	0.79	0.341
11	3	0.18	0.79	0.134	11	3	0.18	0.79	0.269
11	4	0.18	0.79	0.158	11	4	0.18	0.79	0.238
11	5	0.18	0.79	0.239	11	5	0.18	0.79	0.257
11	6	0.18	0.79	0.188	11	6	0.18	0.79	0.257
11	7	0.18	0.79	0.097	11	7	0.18	0.79	0.327
11	8	0.18	0.79	0.069	11	8	0.18	0.79	0.411
11	9	0.18	0.79	0.144	11	9	0.18	0.79	0.403
11	10	0.18	0.79	0.118	11	10	0.18	0.79	0.203
11	11	0.18	0.79	0.071	11	11	0.18	0.79	0.31
11	12	0.18	0.79	0.055	11	12	0.18	0.79	0.288
12	1	0.17	0.79	0.067	12	1	0.17	0.79	0.065
12	2	0.17	0.79	0.035	12	2	0.17	0.79	0.079
12	3	0.17	0.79	0.034	12	3	0.17	0.79	0.051
12	4	0.17	0.79	0.036	12	4	0.17	0.79	0.041
12	5	0.17	0.79	0.062	12	5	0.17	0.79	0.05
12	6	0.17	0.79	0.043	12	6	0.17	0.79	0.052
12	7	0.17	0.79	0.042	12	7	0.17	0.79	0.068
12	8	0.17	0.79	0.038	12	8	0.17	0.79	0.103
12	9	0.17	0.79	0.076	12	9	0.17	0.79	0.095
12	10	0.17	0.79	0.08	12	10	0.17	0.79	0.034
12	11	0.17	0.79	0.057	12	11	0.17	0.79	0.073
12	12	0.17	0.79	0.045	12	12	0.17	0.79	0.055

Enersys Airport					Enersys Site				
Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length	Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length

1	1	0.17	0.79	0.067	1	1	0.17	0.78	0.18
1	2	0.17	0.79	0.035	1	2	0.17	0.78	0.056
1	3	0.17	0.79	0.034	1	3	0.17	0.78	0.143
1	4	0.17	0.79	0.036	1	4	0.17	0.78	0.062
1	5	0.17	0.79	0.062	1	5	0.17	0.78	0.096
1	6	0.17	0.79	0.043	1	6	0.17	0.78	0.149
1	7	0.17	0.79	0.042	1	7	0.17	0.78	0.314
1	8	0.17	0.79	0.038	1	8	0.17	0.78	0.29
1	9	0.17	0.79	0.076	1	9	0.17	0.78	0.519
1	10	0.17	0.79	0.08	1	10	0.17	0.78	0.379
1	11	0.17	0.79	0.057	1	11	0.17	0.78	0.41
1	12	0.17	0.79	0.045	1	12	0.17	0.78	0.24
2	1	0.17	0.79	0.067	2	1	0.17	0.78	0.18
2	2	0.17	0.79	0.035	2	2	0.17	0.78	0.056
2	3	0.17	0.79	0.034	2	3	0.17	0.78	0.143
2	4	0.17	0.79	0.036	2	4	0.17	0.78	0.062
2	5	0.17	0.79	0.062	2	5	0.17	0.78	0.096
2	6	0.17	0.79	0.043	2	6	0.17	0.78	0.149
2	7	0.17	0.79	0.042	2	7	0.17	0.78	0.314
2	8	0.17	0.79	0.038	2	8	0.17	0.78	0.29
2	9	0.17	0.79	0.076	2	9	0.17	0.78	0.519
2	10	0.17	0.79	0.08	2	10	0.17	0.78	0.379
2	11	0.17	0.79	0.057	2	11	0.17	0.78	0.41
2	12	0.17	0.79	0.045	2	12	0.17	0.78	0.24
3	1	0.15	0.41	0.075	3	1	0.14	0.42	0.228
3	2	0.15	0.41	0.046	3	2	0.14	0.42	0.075
3	3	0.15	0.41	0.047	3	3	0.14	0.42	0.181
3	4	0.15	0.41	0.05	3	4	0.14	0.42	0.083
3	5	0.15	0.41	0.089	3	5	0.14	0.42	0.121
3	6	0.15	0.41	0.06	3	6	0.14	0.42	0.183
3	7	0.15	0.41	0.057	3	7	0.14	0.42	0.355

3	8	0.15	0.41	0.048	3	8	0.14	0.42	0.334
3	9	0.15	0.41	0.097	3	9	0.14	0.42	0.56
3	10	0.15	0.41	0.1	3	10	0.14	0.42	0.43
3	11	0.15	0.41	0.068	3	11	0.14	0.42	0.472
3	12	0.15	0.41	0.051	3	12	0.14	0.42	0.284
4	1	0.15	0.41	0.075	4	1	0.14	0.42	0.228
4	2	0.15	0.41	0.046	4	2	0.14	0.42	0.075
4	3	0.15	0.41	0.047	4	3	0.14	0.42	0.181
4	4	0.15	0.41	0.05	4	4	0.14	0.42	0.083
4	5	0.15	0.41	0.089	4	5	0.14	0.42	0.121
4	6	0.15	0.41	0.06	4	6	0.14	0.42	0.183
4	7	0.15	0.41	0.057	4	7	0.14	0.42	0.355
4	8	0.15	0.41	0.048	4	8	0.14	0.42	0.334
4	9	0.15	0.41	0.097	4	9	0.14	0.42	0.56
4	10	0.15	0.41	0.1	4	10	0.14	0.42	0.43
4	11	0.15	0.41	0.068	4	11	0.14	0.42	0.472
4	12	0.15	0.41	0.051	4	12	0.14	0.42	0.284
5	1	0.15	0.41	0.075	5	1	0.14	0.42	0.228
5	2	0.15	0.41	0.046	5	2	0.14	0.42	0.075
5	3	0.15	0.41	0.047	5	3	0.14	0.42	0.181
5	4	0.15	0.41	0.05	5	4	0.14	0.42	0.083
5	5	0.15	0.41	0.089	5	5	0.14	0.42	0.121
5	6	0.15	0.41	0.06	5	6	0.14	0.42	0.183
5	7	0.15	0.41	0.057	5	7	0.14	0.42	0.355
5	8	0.15	0.41	0.048	5	8	0.14	0.42	0.334
5	9	0.15	0.41	0.097	5	9	0.14	0.42	0.56
5	10	0.15	0.41	0.1	5	10	0.14	0.42	0.43
5	11	0.15	0.41	0.068	5	11	0.14	0.42	0.472
5	12	0.15	0.41	0.051	5	12	0.14	0.42	0.284
6	1	0.18	0.5	0.094	6	1	0.18	0.47	0.276
6	2	0.18	0.5	0.117	6	2	0.18	0.47	0.112

6	3	0.18	0.5	0.138	6	3	0.18	0.47	0.373
6	4	0.18	0.5	0.16	6	4	0.18	0.47	0.237
6	5	0.18	0.5	0.242	6	5	0.18	0.47	0.239
6	6	0.18	0.5	0.193	6	6	0.18	0.47	0.356
6	7	0.18	0.5	0.107	6	7	0.18	0.47	0.41
6	8	0.18	0.5	0.077	6	8	0.18	0.47	0.386
6	9	0.18	0.5	0.152	6	9	0.18	0.47	0.59
6	10	0.18	0.5	0.127	6	10	0.18	0.47	0.469
6	11	0.18	0.5	0.076	6	11	0.18	0.47	0.528
6	12	0.18	0.5	0.06	6	12	0.18	0.47	0.325
7	1	0.18	0.5	0.094	7	1	0.18	0.47	0.276
7	2	0.18	0.5	0.117	7	2	0.18	0.47	0.112
7	3	0.18	0.5	0.138	7	3	0.18	0.47	0.373
7	4	0.18	0.5	0.16	7	4	0.18	0.47	0.237
7	5	0.18	0.5	0.242	7	5	0.18	0.47	0.239
7	6	0.18	0.5	0.193	7	6	0.18	0.47	0.356
7	7	0.18	0.5	0.107	7	7	0.18	0.47	0.41
7	8	0.18	0.5	0.077	7	8	0.18	0.47	0.386
7	9	0.18	0.5	0.152	7	9	0.18	0.47	0.59
7	10	0.18	0.5	0.127	7	10	0.18	0.47	0.469
7	11	0.18	0.5	0.076	7	11	0.18	0.47	0.528
7	12	0.18	0.5	0.06	7	12	0.18	0.47	0.325
8	1	0.18	0.5	0.094	8	1	0.18	0.47	0.276
8	2	0.18	0.5	0.117	8	2	0.18	0.47	0.112
8	3	0.18	0.5	0.138	8	3	0.18	0.47	0.373
8	4	0.18	0.5	0.16	8	4	0.18	0.47	0.237
8	5	0.18	0.5	0.242	8	5	0.18	0.47	0.239
8	6	0.18	0.5	0.193	8	6	0.18	0.47	0.356
8	7	0.18	0.5	0.107	8	7	0.18	0.47	0.41
8	8	0.18	0.5	0.077	8	8	0.18	0.47	0.386
8	9	0.18	0.5	0.152	8	9	0.18	0.47	0.59

8	10	0.18	0.5	0.127	8	10	0.18	0.47	0.469
8	11	0.18	0.5	0.076	8	11	0.18	0.47	0.528
8	12	0.18	0.5	0.06	8	12	0.18	0.47	0.325
9	1	0.18	0.79	0.091	9	1	0.18	0.78	0.254
9	2	0.18	0.79	0.114	9	2	0.18	0.78	0.098
9	3	0.18	0.79	0.134	9	3	0.18	0.78	0.367
9	4	0.18	0.79	0.158	9	4	0.18	0.78	0.233
9	5	0.18	0.79	0.239	9	5	0.18	0.78	0.228
9	6	0.18	0.79	0.188	9	6	0.18	0.78	0.348
9	7	0.18	0.79	0.097	9	7	0.18	0.78	0.39
9	8	0.18	0.79	0.069	9	8	0.18	0.78	0.364
9	9	0.18	0.79	0.144	9	9	0.18	0.78	0.574
9	10	0.18	0.79	0.118	9	10	0.18	0.78	0.449
9	11	0.18	0.79	0.071	9	11	0.18	0.78	0.511
9	12	0.18	0.79	0.055	9	12	0.18	0.78	0.304
10	1	0.18	0.79	0.091	10	1	0.18	0.78	0.254
10	2	0.18	0.79	0.114	10	2	0.18	0.78	0.098
10	3	0.18	0.79	0.134	10	3	0.18	0.78	0.367
10	4	0.18	0.79	0.158	10	4	0.18	0.78	0.233
10	5	0.18	0.79	0.239	10	5	0.18	0.78	0.228
10	6	0.18	0.79	0.188	10	6	0.18	0.78	0.348
10	7	0.18	0.79	0.097	10	7	0.18	0.78	0.39
10	8	0.18	0.79	0.069	10	8	0.18	0.78	0.364
10	9	0.18	0.79	0.144	10	9	0.18	0.78	0.574
10	10	0.18	0.79	0.118	10	10	0.18	0.78	0.449
10	11	0.18	0.79	0.071	10	11	0.18	0.78	0.511
10	12	0.18	0.79	0.055	10	12	0.18	0.78	0.304
11	1	0.18	0.79	0.091	11	1	0.18	0.78	0.254
11	2	0.18	0.79	0.114	11	2	0.18	0.78	0.098
11	3	0.18	0.79	0.134	11	3	0.18	0.78	0.367
11	4	0.18	0.79	0.158	11	4	0.18	0.78	0.233

11	5	0.18	0.79	0.239	11	5	0.18	0.78	0.228
11	6	0.18	0.79	0.188	11	6	0.18	0.78	0.348
11	7	0.18	0.79	0.097	11	7	0.18	0.78	0.39
11	8	0.18	0.79	0.069	11	8	0.18	0.78	0.364
11	9	0.18	0.79	0.144	11	9	0.18	0.78	0.574
11	10	0.18	0.79	0.118	11	10	0.18	0.78	0.449
11	11	0.18	0.79	0.071	11	11	0.18	0.78	0.511
11	12	0.18	0.79	0.055	11	12	0.18	0.78	0.304
12	1	0.17	0.79	0.067	12	1	0.17	0.78	0.18
12	2	0.17	0.79	0.035	12	2	0.17	0.78	0.056
12	3	0.17	0.79	0.034	12	3	0.17	0.78	0.143
12	4	0.17	0.79	0.036	12	4	0.17	0.78	0.062
12	5	0.17	0.79	0.062	12	5	0.17	0.78	0.096
12	6	0.17	0.79	0.043	12	6	0.17	0.78	0.149
12	7	0.17	0.79	0.042	12	7	0.17	0.78	0.314
12	8	0.17	0.79	0.038	12	8	0.17	0.78	0.29
12	9	0.17	0.79	0.076	12	9	0.17	0.78	0.519
12	10	0.17	0.79	0.08	12	10	0.17	0.78	0.379
12	11	0.17	0.79	0.057	12	11	0.17	0.78	0.41
12	12	0.17	0.79	0.045	12	12	0.17	0.78	0.24

Big Sandy Airport					Big Sandy Site				
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness Length**	**Month**	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness Length**
1	1	0.16	0.82	0.232	1	1	0.17	0.93	0.133
1	2	0.16	0.82	0.206	1	2	0.17	0.93	0.028
1	3	0.16	0.82	0.299	1	3	0.17	0.93	0.037
1	4	0.16	0.82	0.488	1	4	0.17	0.93	0.119
1	5	0.16	0.82	0.372	1	5	0.17	0.93	0.106
1	6	0.16	0.82	0.199	1	6	0.17	0.93	0.185

1	7	0.16	0.82	0.192	1	7	0.17	0.93	0.283
1	8	0.16	0.82	0.044	1	8	0.17	0.93	0.272
1	9	0.16	0.82	0.04	1	9	0.17	0.93	0.165
1	10	0.16	0.82	0.06	1	10	0.17	0.93	0.274
1	11	0.16	0.82	0.383	1	11	0.17	0.93	0.402
1	12	0.16	0.82	0.303	1	12	0.17	0.93	0.292
2	1	0.16	0.82	0.232	2	1	0.17	0.93	0.133
2	2	0.16	0.82	0.206	2	2	0.17	0.93	0.028
2	3	0.16	0.82	0.299	2	3	0.17	0.93	0.037
2	4	0.16	0.82	0.488	2	4	0.17	0.93	0.119
2	5	0.16	0.82	0.372	2	5	0.17	0.93	0.106
2	6	0.16	0.82	0.199	2	6	0.17	0.93	0.185
2	7	0.16	0.82	0.192	2	7	0.17	0.93	0.283
2	8	0.16	0.82	0.044	2	8	0.17	0.93	0.272
2	9	0.16	0.82	0.04	2	9	0.17	0.93	0.165
2	10	0.16	0.82	0.06	2	10	0.17	0.93	0.274
2	11	0.16	0.82	0.383	2	11	0.17	0.93	0.402
2	12	0.16	0.82	0.303	2	12	0.17	0.93	0.292
3	1	0.15	0.56	0.356	3	1	0.16	0.64	0.182
3	2	0.15	0.56	0.311	3	2	0.16	0.64	0.035
3	3	0.15	0.56	0.463	3	3	0.16	0.64	0.048
3	4	0.15	0.56	0.772	3	4	0.16	0.64	0.168
3	5	0.15	0.56	0.574	3	5	0.16	0.64	0.152
3	6	0.15	0.56	0.279	3	6	0.16	0.64	0.262
3	7	0.15	0.56	0.28	3	7	0.16	0.64	0.394
3	8	0.15	0.56	0.062	3	8	0.16	0.64	0.351
3	9	0.15	0.56	0.055	3	9	0.16	0.64	0.181
3	10	0.15	0.56	0.079	3	10	0.16	0.64	0.322
3	11	0.15	0.56	0.566	3	11	0.16	0.64	0.626
3	12	0.15	0.56	0.451	3	12	0.16	0.64	0.44
4	1	0.15	0.56	0.356	4	1	0.16	0.64	0.182

4	2	0.15	0.56	0.311	4	2	0.16	0.64	0.035
4	3	0.15	0.56	0.463	4	3	0.16	0.64	0.048
4	4	0.15	0.56	0.772	4	4	0.16	0.64	0.168
4	5	0.15	0.56	0.574	4	5	0.16	0.64	0.152
4	6	0.15	0.56	0.279	4	6	0.16	0.64	0.262
4	7	0.15	0.56	0.28	4	7	0.16	0.64	0.394
4	8	0.15	0.56	0.062	4	8	0.16	0.64	0.351
4	9	0.15	0.56	0.055	4	9	0.16	0.64	0.181
4	10	0.15	0.56	0.079	4	10	0.16	0.64	0.322
4	11	0.15	0.56	0.566	4	11	0.16	0.64	0.626
4	12	0.15	0.56	0.451	4	12	0.16	0.64	0.44
5	1	0.15	0.56	0.356	5	1	0.16	0.64	0.182
5	2	0.15	0.56	0.311	5	2	0.16	0.64	0.035
5	3	0.15	0.56	0.463	5	3	0.16	0.64	0.048
5	4	0.15	0.56	0.772	5	4	0.16	0.64	0.168
5	5	0.15	0.56	0.574	5	5	0.16	0.64	0.152
5	6	0.15	0.56	0.279	5	6	0.16	0.64	0.262
5	7	0.15	0.56	0.28	5	7	0.16	0.64	0.394
5	8	0.15	0.56	0.062	5	8	0.16	0.64	0.351
5	9	0.15	0.56	0.055	5	9	0.16	0.64	0.181
5	10	0.15	0.56	0.079	5	10	0.16	0.64	0.322
5	11	0.15	0.56	0.566	5	11	0.16	0.64	0.626
5	12	0.15	0.56	0.451	5	12	0.16	0.64	0.44
6	1	0.16	0.39	0.684	6	1	0.16	0.32	0.222
6	2	0.16	0.39	0.642	6	2	0.16	0.32	0.039
6	3	0.16	0.39	0.803	6	3	0.16	0.32	0.055
6	4	0.16	0.39	1.096	6	4	0.16	0.32	0.201
6	5	0.16	0.39	0.86	6	5	0.16	0.32	0.201
6	6	0.16	0.39	0.447	6	6	0.16	0.32	0.331
6	7	0.16	0.39	0.434	6	7	0.16	0.32	0.527
6	8	0.16	0.39	0.12	6	8	0.16	0.32	0.416

6	9	0.16	0.39	0.115	6	9	0.16	0.32	0.192
6	10	0.16	0.39	0.123	6	10	0.16	0.32	0.378
6	11	0.16	0.39	0.742	6	11	0.16	0.32	0.834
6	12	0.16	0.39	0.714	6	12	0.16	0.32	0.575
7	1	0.16	0.39	0.684	7	1	0.16	0.32	0.222
7	2	0.16	0.39	0.642	7	2	0.16	0.32	0.039
7	3	0.16	0.39	0.803	7	3	0.16	0.32	0.055
7	4	0.16	0.39	1.096	7	4	0.16	0.32	0.201
7	5	0.16	0.39	0.86	7	5	0.16	0.32	0.201
7	6	0.16	0.39	0.447	7	6	0.16	0.32	0.331
7	7	0.16	0.39	0.434	7	7	0.16	0.32	0.527
7	8	0.16	0.39	0.12	7	8	0.16	0.32	0.416
7	9	0.16	0.39	0.115	7	9	0.16	0.32	0.192
7	10	0.16	0.39	0.123	7	10	0.16	0.32	0.378
7	11	0.16	0.39	0.742	7	11	0.16	0.32	0.834
7	12	0.16	0.39	0.714	7	12	0.16	0.32	0.575
8	1	0.16	0.39	0.684	8	1	0.16	0.32	0.222
8	2	0.16	0.39	0.642	8	2	0.16	0.32	0.039
8	3	0.16	0.39	0.803	8	3	0.16	0.32	0.055
8	4	0.16	0.39	1.096	8	4	0.16	0.32	0.201
8	5	0.16	0.39	0.86	8	5	0.16	0.32	0.201
8	6	0.16	0.39	0.447	8	6	0.16	0.32	0.331
8	7	0.16	0.39	0.434	8	7	0.16	0.32	0.527
8	8	0.16	0.39	0.12	8	8	0.16	0.32	0.416
8	9	0.16	0.39	0.115	8	9	0.16	0.32	0.192
8	10	0.16	0.39	0.123	8	10	0.16	0.32	0.378
8	11	0.16	0.39	0.742	8	11	0.16	0.32	0.834
8	12	0.16	0.39	0.714	8	12	0.16	0.32	0.575
9	1	0.16	0.82	0.684	9	1	0.16	0.93	0.221
9	2	0.16	0.82	0.642	9	2	0.16	0.93	0.039
9	3	0.16	0.82	0.803	9	3	0.16	0.93	0.055

9	4	0.16	0.82	1.096	9	4	0.16	0.93	0.201
9	5	0.16	0.82	0.86	9	5	0.16	0.93	0.201
9	6	0.16	0.82	0.443	9	6	0.16	0.93	0.331
9	7	0.16	0.82	0.42	9	7	0.16	0.93	0.527
9	8	0.16	0.82	0.111	9	8	0.16	0.93	0.415
9	9	0.16	0.82	0.107	9	9	0.16	0.93	0.191
9	10	0.16	0.82	0.115	9	10	0.16	0.93	0.378
9	11	0.16	0.82	0.735	9	11	0.16	0.93	0.834
9	12	0.16	0.82	0.714	9	12	0.16	0.93	0.569
10	1	0.16	0.82	0.684	10	1	0.16	0.93	0.221
10	2	0.16	0.82	0.642	10	2	0.16	0.93	0.039
10	3	0.16	0.82	0.803	10	3	0.16	0.93	0.055
10	4	0.16	0.82	1.096	10	4	0.16	0.93	0.201
10	5	0.16	0.82	0.86	10	5	0.16	0.93	0.201
10	6	0.16	0.82	0.443	10	6	0.16	0.93	0.331
10	7	0.16	0.82	0.42	10	7	0.16	0.93	0.527
10	8	0.16	0.82	0.111	10	8	0.16	0.93	0.415
10	9	0.16	0.82	0.107	10	9	0.16	0.93	0.191
10	10	0.16	0.82	0.115	10	10	0.16	0.93	0.378
10	11	0.16	0.82	0.735	10	11	0.16	0.93	0.834
10	12	0.16	0.82	0.714	10	12	0.16	0.93	0.569
11	1	0.16	0.82	0.684	11	1	0.16	0.93	0.221
11	2	0.16	0.82	0.642	11	2	0.16	0.93	0.039
11	3	0.16	0.82	0.803	11	3	0.16	0.93	0.055
11	4	0.16	0.82	1.096	11	4	0.16	0.93	0.201
11	5	0.16	0.82	0.86	11	5	0.16	0.93	0.201
11	6	0.16	0.82	0.443	11	6	0.16	0.93	0.331
11	7	0.16	0.82	0.42	11	7	0.16	0.93	0.527
11	8	0.16	0.82	0.111	11	8	0.16	0.93	0.415
11	9	0.16	0.82	0.107	11	9	0.16	0.93	0.191
11	10	0.16	0.82	0.115	11	10	0.16	0.93	0.378

11	11	0.16	0.82	0.735	11	11	0.16	0.93	0.834
11	12	0.16	0.82	0.714	11	12	0.16	0.93	0.569
12	1	0.16	0.82	0.232	12	1	0.17	0.93	0.133
12	2	0.16	0.82	0.206	12	2	0.17	0.93	0.028
12	3	0.16	0.82	0.299	12	3	0.17	0.93	0.037
12	4	0.16	0.82	0.488	12	4	0.17	0.93	0.119
12	5	0.16	0.82	0.372	12	5	0.17	0.93	0.106
12	6	0.16	0.82	0.199	12	6	0.17	0.93	0.185
12	7	0.16	0.82	0.192	12	7	0.17	0.93	0.283
12	8	0.16	0.82	0.044	12	8	0.17	0.93	0.272
12	9	0.16	0.82	0.04	12	9	0.17	0.93	0.165
12	10	0.16	0.82	0.06	12	10	0.17	0.93	0.274
12	11	0.16	0.82	0.383	12	11	0.17	0.93	0.402
12	12	0.16	0.82	0.303	12	12	0.17	0.93	0.292

Calgon Carbon Airport					Calgon Carbon Surface				
Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length	Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length
1	1	0.16	0.82	0.23	1	1	0.17	0.91	0.166
1	2	0.16	0.82	0.208	1	2	0.17	0.91	0.189
1	3	0.16	0.82	0.293	1	3	0.17	0.91	0.097
1	4	0.16	0.82	0.488	1	4	0.17	0.91	0.017
1	5	0.16	0.82	0.373	1	5	0.17	0.91	0.058
1	6	0.16	0.82	0.198	1	6	0.17	0.91	0.689
1	7	0.16	0.82	0.195	1	7	0.17	0.91	0.204
1	8	0.16	0.82	0.041	1	8	0.17	0.91	0.557
1	9	0.16	0.82	0.043	1	9	0.17	0.91	0.279
1	10	0.16	0.82	0.055	1	10	0.17	0.91	0.489
1	11	0.16	0.82	0.383	1	11	0.17	0.91	0.048
1	12	0.16	0.82	0.294	1	12	0.17	0.91	0.146

2	1	0.16	0.82	0.23	2	1	0.17	0.91	0.166
2	2	0.16	0.82	0.208	2	2	0.17	0.91	0.189
2	3	0.16	0.82	0.293	2	3	0.17	0.91	0.097
2	4	0.16	0.82	0.488	2	4	0.17	0.91	0.017
2	5	0.16	0.82	0.373	2	5	0.17	0.91	0.058
2	6	0.16	0.82	0.198	2	6	0.17	0.91	0.689
2	7	0.16	0.82	0.195	2	7	0.17	0.91	0.204
2	8	0.16	0.82	0.041	2	8	0.17	0.91	0.557
2	9	0.16	0.82	0.043	2	9	0.17	0.91	0.279
2	10	0.16	0.82	0.055	2	10	0.17	0.91	0.489
2	11	0.16	0.82	0.383	2	11	0.17	0.91	0.048
2	12	0.16	0.82	0.294	2	12	0.17	0.91	0.146
3	1	0.15	0.56	0.352	3	1	0.15	0.61	0.216
3	2	0.15	0.56	0.317	3	2	0.15	0.61	0.262
3	3	0.15	0.56	0.452	3	3	0.15	0.61	0.126
3	4	0.15	0.56	0.773	3	4	0.15	0.61	0.019
3	5	0.15	0.56	0.575	3	5	0.15	0.61	0.062
3	6	0.15	0.56	0.278	3	6	0.15	0.61	0.877
3	7	0.15	0.56	0.284	3	7	0.15	0.61	0.276
3	8	0.15	0.56	0.058	3	8	0.15	0.61	0.855
3	9	0.15	0.56	0.06	3	9	0.15	0.61	0.407
3	10	0.15	0.56	0.071	3	10	0.15	0.61	0.736
3	11	0.15	0.56	0.565	3	11	0.15	0.61	0.063
3	12	0.15	0.56	0.436	3	12	0.15	0.61	0.178
4	1	0.15	0.56	0.352	4	1	0.15	0.61	0.216
4	2	0.15	0.56	0.317	4	2	0.15	0.61	0.262
4	3	0.15	0.56	0.452	4	3	0.15	0.61	0.126
4	4	0.15	0.56	0.773	4	4	0.15	0.61	0.019
4	5	0.15	0.56	0.575	4	5	0.15	0.61	0.062
4	6	0.15	0.56	0.278	4	6	0.15	0.61	0.877
4	7	0.15	0.56	0.284	4	7	0.15	0.61	0.276

4	8	0.15	0.56	0.058	4	8	0.15	0.61	0.855
4	9	0.15	0.56	0.06	4	9	0.15	0.61	0.407
4	10	0.15	0.56	0.071	4	10	0.15	0.61	0.736
4	11	0.15	0.56	0.565	4	11	0.15	0.61	0.063
4	12	0.15	0.56	0.436	4	12	0.15	0.61	0.178
5	1	0.15	0.56	0.352	5	1	0.15	0.61	0.216
5	2	0.15	0.56	0.317	5	2	0.15	0.61	0.262
5	3	0.15	0.56	0.452	5	3	0.15	0.61	0.126
5	4	0.15	0.56	0.773	5	4	0.15	0.61	0.019
5	5	0.15	0.56	0.575	5	5	0.15	0.61	0.062
5	6	0.15	0.56	0.278	5	6	0.15	0.61	0.877
5	7	0.15	0.56	0.284	5	7	0.15	0.61	0.276
5	8	0.15	0.56	0.058	5	8	0.15	0.61	0.855
5	9	0.15	0.56	0.06	5	9	0.15	0.61	0.407
5	10	0.15	0.56	0.071	5	10	0.15	0.61	0.736
5	11	0.15	0.56	0.565	5	11	0.15	0.61	0.063
5	12	0.15	0.56	0.436	5	12	0.15	0.61	0.178
6	1	0.16	0.39	0.68	6	1	0.16	0.35	0.261
6	2	0.16	0.39	0.65	6	2	0.16	0.35	0.312
6	3	0.16	0.39	0.791	6	3	0.16	0.35	0.159
6	4	0.16	0.39	1.096	6	4	0.16	0.35	0.023
6	5	0.16	0.39	0.857	6	5	0.16	0.35	0.065
6	6	0.16	0.39	0.447	6	6	0.16	0.35	1.003
6	7	0.16	0.39	0.44	6	7	0.16	0.35	0.327
6	8	0.16	0.39	0.116	6	8	0.16	0.35	1.123
6	9	0.16	0.39	0.12	6	9	0.16	0.35	0.618
6	10	0.16	0.39	0.115	6	10	0.16	0.35	1.042
6	11	0.16	0.39	0.738	6	11	0.16	0.35	0.076
6	12	0.16	0.39	0.695	6	12	0.16	0.35	0.247
7	1	0.16	0.39	0.68	7	1	0.16	0.35	0.261
7	2	0.16	0.39	0.65	7	2	0.16	0.35	0.312

7	3	0.16	0.39	0.791	7	3	0.16	0.35	0.159
7	4	0.16	0.39	1.096	7	4	0.16	0.35	0.023
7	5	0.16	0.39	0.857	7	5	0.16	0.35	0.065
7	6	0.16	0.39	0.447	7	6	0.16	0.35	1.003
7	7	0.16	0.39	0.44	7	7	0.16	0.35	0.327
7	8	0.16	0.39	0.116	7	8	0.16	0.35	1.123
7	9	0.16	0.39	0.12	7	9	0.16	0.35	0.618
7	10	0.16	0.39	0.115	7	10	0.16	0.35	1.042
7	11	0.16	0.39	0.738	7	11	0.16	0.35	0.076
7	12	0.16	0.39	0.695	7	12	0.16	0.35	0.247
8	1	0.16	0.39	0.68	8	1	0.16	0.35	0.261
8	2	0.16	0.39	0.65	8	2	0.16	0.35	0.312
8	3	0.16	0.39	0.791	8	3	0.16	0.35	0.159
8	4	0.16	0.39	1.096	8	4	0.16	0.35	0.023
8	5	0.16	0.39	0.857	8	5	0.16	0.35	0.065
8	6	0.16	0.39	0.447	8	6	0.16	0.35	1.003
8	7	0.16	0.39	0.44	8	7	0.16	0.35	0.327
8	8	0.16	0.39	0.116	8	8	0.16	0.35	1.123
8	9	0.16	0.39	0.12	8	9	0.16	0.35	0.618
8	10	0.16	0.39	0.115	8	10	0.16	0.35	1.042
8	11	0.16	0.39	0.738	8	11	0.16	0.35	0.076
8	12	0.16	0.39	0.695	8	12	0.16	0.35	0.247
9	1	0.16	0.82	0.68	9	1	0.16	0.91	0.261
9	2	0.16	0.82	0.65	9	2	0.16	0.91	0.312
9	3	0.16	0.82	0.791	9	3	0.16	0.91	0.159
9	4	0.16	0.82	1.096	9	4	0.16	0.91	0.023
9	5	0.16	0.82	0.857	9	5	0.16	0.91	0.065
9	6	0.16	0.82	0.443	9	6	0.16	0.91	1.003
9	7	0.16	0.82	0.427	9	7	0.16	0.91	0.327
9	8	0.16	0.82	0.107	9	8	0.16	0.91	1.123
9	9	0.16	0.82	0.112	9	9	0.16	0.91	0.618

9	10	0.16	0.82	0.107	9	10	0.16	0.91	1.042
9	11	0.16	0.82	0.731	9	11	0.16	0.91	0.076
9	12	0.16	0.82	0.695	9	12	0.16	0.91	0.247
10	1	0.16	0.82	0.68	10	1	0.16	0.91	0.261
10	2	0.16	0.82	0.65	10	2	0.16	0.91	0.312
10	3	0.16	0.82	0.791	10	3	0.16	0.91	0.159
10	4	0.16	0.82	1.096	10	4	0.16	0.91	0.023
10	5	0.16	0.82	0.857	10	5	0.16	0.91	0.065
10	6	0.16	0.82	0.443	10	6	0.16	0.91	1.003
10	7	0.16	0.82	0.427	10	7	0.16	0.91	0.327
10	8	0.16	0.82	0.107	10	8	0.16	0.91	1.123
10	9	0.16	0.82	0.112	10	9	0.16	0.91	0.618
10	10	0.16	0.82	0.107	10	10	0.16	0.91	1.042
10	11	0.16	0.82	0.731	10	11	0.16	0.91	0.076
10	12	0.16	0.82	0.695	10	12	0.16	0.91	0.247
11	1	0.16	0.82	0.68	11	1	0.16	0.91	0.261
11	2	0.16	0.82	0.65	11	2	0.16	0.91	0.312
11	3	0.16	0.82	0.791	11	3	0.16	0.91	0.159
11	4	0.16	0.82	1.096	11	4	0.16	0.91	0.023
11	5	0.16	0.82	0.857	11	5	0.16	0.91	0.065
11	6	0.16	0.82	0.443	11	6	0.16	0.91	1.003
11	7	0.16	0.82	0.427	11	7	0.16	0.91	0.327
11	8	0.16	0.82	0.107	11	8	0.16	0.91	1.123
11	9	0.16	0.82	0.112	11	9	0.16	0.91	0.618
11	10	0.16	0.82	0.107	11	10	0.16	0.91	1.042
11	11	0.16	0.82	0.731	11	11	0.16	0.91	0.076
11	12	0.16	0.82	0.695	11	12	0.16	0.91	0.247
12	1	0.16	0.82	0.23	12	1	0.17	0.91	0.166
12	2	0.16	0.82	0.208	12	2	0.17	0.91	0.189
12	3	0.16	0.82	0.293	12	3	0.17	0.91	0.097
12	4	0.16	0.82	0.488	12	4	0.17	0.91	0.017

12	5	0.16	0.82	0.373	12	5	0.17	0.91	0.058
12	6	0.16	0.82	0.198	12	6	0.17	0.91	0.689
12	7	0.16	0.82	0.195	12	7	0.17	0.91	0.204
12	8	0.16	0.82	0.041	12	8	0.17	0.91	0.557
12	9	0.16	0.82	0.043	12	9	0.17	0.91	0.279
12	10	0.16	0.82	0.055	12	10	0.17	0.91	0.489
12	11	0.16	0.82	0.383	12	11	0.17	0.91	0.048
12	12	0.16	0.82	0.294	12	12	0.17	0.91	0.146

Newpage Airport					Newpage Site				
Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length	Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length
1	1	0.17	0.72	0.04	1	1	0.16	0.49	0.492
1	2	0.17	0.72	0.054	1	2	0.16	0.49	0.507
1	3	0.17	0.72	0.037	1	3	0.16	0.49	0.624
1	4	0.17	0.72	0.026	1	4	0.16	0.49	0.422
1	5	0.17	0.72	0.022	1	5	0.16	0.49	0.211
1	6	0.17	0.72	0.022	1	6	0.16	0.49	0.342
1	7	0.17	0.72	0.02	1	7	0.16	0.49	0.385
1	8	0.17	0.72	0.014	1	8	0.16	0.49	0.115
1	9	0.17	0.72	0.017	1	9	0.16	0.49	0.285
1	10	0.17	0.72	0.021	1	10	0.16	0.49	0.536
1	11	0.17	0.72	0.024	1	11	0.16	0.49	0.475
1	12	0.17	0.72	0.028	1	12	0.16	0.49	0.354
2	1	0.17	0.72	0.04	2	1	0.16	0.49	0.492
2	2	0.17	0.72	0.054	2	2	0.16	0.49	0.507
2	3	0.17	0.72	0.037	2	3	0.16	0.49	0.624
2	4	0.17	0.72	0.026	2	4	0.16	0.49	0.422
2	5	0.17	0.72	0.022	2	5	0.16	0.49	0.211

2	6	0.17	0.72	0.022	2	6	0.16	0.49	0.342
2	7	0.17	0.72	0.02	2	7	0.16	0.49	0.385
2	8	0.17	0.72	0.014	2	8	0.16	0.49	0.115
2	9	0.17	0.72	0.017	2	9	0.16	0.49	0.285
2	10	0.17	0.72	0.021	2	10	0.16	0.49	0.536
2	11	0.17	0.72	0.024	2	11	0.16	0.49	0.475
2	12	0.17	0.72	0.028	2	12	0.16	0.49	0.354
3	1	0.14	0.36	0.057	3	1	0.14	0.29	0.684
3	2	0.14	0.36	0.076	3	2	0.14	0.29	0.691
3	3	0.14	0.36	0.053	3	3	0.14	0.29	0.791
3	4	0.14	0.36	0.038	3	4	0.14	0.29	0.446
3	5	0.14	0.36	0.032	3	5	0.14	0.29	0.255
3	6	0.14	0.36	0.03	3	6	0.14	0.29	0.403
3	7	0.14	0.36	0.027	3	7	0.14	0.29	0.442
3	8	0.14	0.36	0.021	3	8	0.14	0.29	0.141
3	9	0.14	0.36	0.025	3	9	0.14	0.29	0.322
3	10	0.14	0.36	0.031	3	10	0.14	0.29	0.62
3	11	0.14	0.36	0.036	3	11	0.14	0.29	0.622
3	12	0.14	0.36	0.042	3	12	0.14	0.29	0.471
4	1	0.14	0.36	0.057	4	1	0.14	0.29	0.684
4	2	0.14	0.36	0.076	4	2	0.14	0.29	0.691
4	3	0.14	0.36	0.053	4	3	0.14	0.29	0.791
4	4	0.14	0.36	0.038	4	4	0.14	0.29	0.446
4	5	0.14	0.36	0.032	4	5	0.14	0.29	0.255
4	6	0.14	0.36	0.03	4	6	0.14	0.29	0.403
4	7	0.14	0.36	0.027	4	7	0.14	0.29	0.442
4	8	0.14	0.36	0.021	4	8	0.14	0.29	0.141
4	9	0.14	0.36	0.025	4	9	0.14	0.29	0.322
4	10	0.14	0.36	0.031	4	10	0.14	0.29	0.62
4	11	0.14	0.36	0.036	4	11	0.14	0.29	0.622
4	12	0.14	0.36	0.042	4	12	0.14	0.29	0.471

5	1	0.14	0.36	0.057	5	1	0.14	0.29	0.684
5	2	0.14	0.36	0.076	5	2	0.14	0.29	0.691
5	3	0.14	0.36	0.053	5	3	0.14	0.29	0.791
5	4	0.14	0.36	0.038	5	4	0.14	0.29	0.446
5	5	0.14	0.36	0.032	5	5	0.14	0.29	0.255
5	6	0.14	0.36	0.03	5	6	0.14	0.29	0.403
5	7	0.14	0.36	0.027	5	7	0.14	0.29	0.442
5	8	0.14	0.36	0.021	5	8	0.14	0.29	0.141
5	9	0.14	0.36	0.025	5	9	0.14	0.29	0.322
5	10	0.14	0.36	0.031	5	10	0.14	0.29	0.62
5	11	0.14	0.36	0.036	5	11	0.14	0.29	0.622
5	12	0.14	0.36	0.042	5	12	0.14	0.29	0.471
6	1	0.19	0.45	0.239	6	1	0.17	0.32	0.929
6	2	0.19	0.45	0.234	6	2	0.17	0.32	0.923
6	3	0.19	0.45	0.189	6	3	0.17	0.32	0.925
6	4	0.19	0.45	0.168	6	4	0.17	0.32	0.475
6	5	0.19	0.45	0.118	6	5	0.17	0.32	0.448
6	6	0.19	0.45	0.059	6	6	0.17	0.32	0.572
6	7	0.19	0.45	0.033	6	7	0.17	0.32	0.574
6	8	0.19	0.45	0.028	6	8	0.17	0.32	0.221
6	9	0.19	0.45	0.041	6	9	0.17	0.32	0.5
6	10	0.19	0.45	0.098	6	10	0.17	0.32	0.739
6	11	0.19	0.45	0.18	6	11	0.17	0.32	0.836
6	12	0.19	0.45	0.163	6	12	0.17	0.32	0.734
7	1	0.19	0.45	0.239	7	1	0.17	0.32	0.929
7	2	0.19	0.45	0.234	7	2	0.17	0.32	0.923
7	3	0.19	0.45	0.189	7	3	0.17	0.32	0.925
7	4	0.19	0.45	0.168	7	4	0.17	0.32	0.475
7	5	0.19	0.45	0.118	7	5	0.17	0.32	0.448
7	6	0.19	0.45	0.059	7	6	0.17	0.32	0.572
7	7	0.19	0.45	0.033	7	7	0.17	0.32	0.574

7	8	0.19	0.45	0.028	7	8	0.17	0.32	0.221
7	9	0.19	0.45	0.041	7	9	0.17	0.32	0.5
7	10	0.19	0.45	0.098	7	10	0.17	0.32	0.739
7	11	0.19	0.45	0.18	7	11	0.17	0.32	0.836
7	12	0.19	0.45	0.163	7	12	0.17	0.32	0.734
8	1	0.19	0.45	0.239	8	1	0.17	0.32	0.929
8	2	0.19	0.45	0.234	8	2	0.17	0.32	0.923
8	3	0.19	0.45	0.189	8	3	0.17	0.32	0.925
8	4	0.19	0.45	0.168	8	4	0.17	0.32	0.475
8	5	0.19	0.45	0.118	8	5	0.17	0.32	0.448
8	6	0.19	0.45	0.059	8	6	0.17	0.32	0.572
8	7	0.19	0.45	0.033	8	7	0.17	0.32	0.574
8	8	0.19	0.45	0.028	8	8	0.17	0.32	0.221
8	9	0.19	0.45	0.041	8	9	0.17	0.32	0.5
8	10	0.19	0.45	0.098	8	10	0.17	0.32	0.739
8	11	0.19	0.45	0.18	8	11	0.17	0.32	0.836
8	12	0.19	0.45	0.163	8	12	0.17	0.32	0.734
9	1	0.19	0.71	0.239	9	1	0.17	0.46	0.929
9	2	0.19	0.71	0.231	9	2	0.17	0.46	0.923
9	3	0.19	0.71	0.187	9	3	0.17	0.46	0.925
9	4	0.19	0.71	0.166	9	4	0.17	0.46	0.475
9	5	0.19	0.71	0.111	9	5	0.17	0.46	0.448
9	6	0.19	0.71	0.052	9	6	0.17	0.46	0.572
9	7	0.19	0.71	0.027	9	7	0.17	0.46	0.57
9	8	0.19	0.71	0.022	9	8	0.17	0.46	0.211
9	9	0.19	0.71	0.034	9	9	0.17	0.46	0.494
9	10	0.19	0.71	0.091	9	10	0.17	0.46	0.738
9	11	0.19	0.71	0.18	9	11	0.17	0.46	0.836
9	12	0.19	0.71	0.157	9	12	0.17	0.46	0.734
10	1	0.19	0.71	0.239	10	1	0.17	0.46	0.929
10	2	0.19	0.71	0.231	10	2	0.17	0.46	0.923

10	3	0.19	0.71	0.187	10	3	0.17	0.46	0.925
10	4	0.19	0.71	0.166	10	4	0.17	0.46	0.475
10	5	0.19	0.71	0.111	10	5	0.17	0.46	0.448
10	6	0.19	0.71	0.052	10	6	0.17	0.46	0.572
10	7	0.19	0.71	0.027	10	7	0.17	0.46	0.57
10	8	0.19	0.71	0.022	10	8	0.17	0.46	0.211
10	9	0.19	0.71	0.034	10	9	0.17	0.46	0.494
10	10	0.19	0.71	0.091	10	10	0.17	0.46	0.738
10	11	0.19	0.71	0.18	10	11	0.17	0.46	0.836
10	12	0.19	0.71	0.157	10	12	0.17	0.46	0.734
11	1	0.19	0.71	0.239	11	1	0.17	0.46	0.929
11	2	0.19	0.71	0.231	11	2	0.17	0.46	0.923
11	3	0.19	0.71	0.187	11	3	0.17	0.46	0.925
11	4	0.19	0.71	0.166	11	4	0.17	0.46	0.475
11	5	0.19	0.71	0.111	11	5	0.17	0.46	0.448
11	6	0.19	0.71	0.052	11	6	0.17	0.46	0.572
11	7	0.19	0.71	0.027	11	7	0.17	0.46	0.57
11	8	0.19	0.71	0.022	11	8	0.17	0.46	0.211
11	9	0.19	0.71	0.034	11	9	0.17	0.46	0.494
11	10	0.19	0.71	0.091	11	10	0.17	0.46	0.738
11	11	0.19	0.71	0.18	11	11	0.17	0.46	0.836
11	12	0.19	0.71	0.157	11	12	0.17	0.46	0.734
12	1	0.17	0.72	0.04	12	1	0.16	0.49	0.492
12	2	0.17	0.72	0.054	12	2	0.16	0.49	0.507
12	3	0.17	0.72	0.037	12	3	0.16	0.49	0.624
12	4	0.17	0.72	0.026	12	4	0.16	0.49	0.422
12	5	0.17	0.72	0.022	12	5	0.16	0.49	0.211
12	6	0.17	0.72	0.022	12	6	0.16	0.49	0.342
12	7	0.17	0.72	0.02	12	7	0.16	0.49	0.385
12	8	0.17	0.72	0.014	12	8	0.16	0.49	0.115
12	9	0.17	0.72	0.017	12	9	0.16	0.49	0.285

12	10	0.17	0.72	0.021	12	10	0.16	0.49	0.536
12	11	0.17	0.72	0.024	12	11	0.16	0.49	0.475
12	12	0.17	0.72	0.028	12	12	0.16	0.49	0.354

TVA Shawnee Airport					TVA Shawnee Site				
Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length	Month	Sector	Albedo	Bowen Ratio	Surface Roughness Length
1	1	0.17	0.72	0.04	1	1	0.16	0.53	0.048
1	2	0.17	0.72	0.054	1	2	0.16	0.53	0.009
1	3	0.17	0.72	0.037	1	3	0.16	0.53	0.036
1	4	0.17	0.72	0.026	1	4	0.16	0.53	0.109
1	5	0.17	0.72	0.022	1	5	0.16	0.53	0.18
1	6	0.17	0.72	0.022	1	6	0.16	0.53	0.123
1	7	0.17	0.72	0.02	1	7	0.16	0.53	0.18
1	8	0.17	0.72	0.014	1	8	0.16	0.53	0.16
1	9	0.17	0.72	0.017	1	9	0.16	0.53	0.045
1	10	0.17	0.72	0.021	1	10	0.16	0.53	0.009
1	11	0.17	0.72	0.024	1	11	0.16	0.53	0.054
1	12	0.17	0.72	0.028	1	12	0.16	0.53	0.085
2	1	0.17	0.72	0.04	2	1	0.16	0.53	0.048
2	2	0.17	0.72	0.054	2	2	0.16	0.53	0.009
2	3	0.17	0.72	0.037	2	3	0.16	0.53	0.036
2	4	0.17	0.72	0.026	2	4	0.16	0.53	0.109
2	5	0.17	0.72	0.022	2	5	0.16	0.53	0.18
2	6	0.17	0.72	0.022	2	6	0.16	0.53	0.123
2	7	0.17	0.72	0.02	2	7	0.16	0.53	0.18
2	8	0.17	0.72	0.014	2	8	0.16	0.53	0.16
2	9	0.17	0.72	0.017	2	9	0.16	0.53	0.045
2	10	0.17	0.72	0.021	2	10	0.16	0.53	0.009
2	11	0.17	0.72	0.024	2	11	0.16	0.53	0.054
2	12	0.17	0.72	0.028	2	12	0.16	0.53	0.085

3	1	0.14	0.36	0.057	3	1	0.14	0.31	0.056
3	2	0.14	0.36	0.076	3	2	0.14	0.31	0.01
3	3	0.14	0.36	0.053	3	3	0.14	0.31	0.041
3	4	0.14	0.36	0.038	3	4	0.14	0.31	0.129
3	5	0.14	0.36	0.032	3	5	0.14	0.31	0.242
3	6	0.14	0.36	0.03	3	6	0.14	0.31	0.148
3	7	0.14	0.36	0.027	3	7	0.14	0.31	0.199
3	8	0.14	0.36	0.021	3	8	0.14	0.31	0.186
3	9	0.14	0.36	0.025	3	9	0.14	0.31	0.048
3	10	0.14	0.36	0.031	3	10	0.14	0.31	0.009
3	11	0.14	0.36	0.036	3	11	0.14	0.31	0.059
3	12	0.14	0.36	0.042	3	12	0.14	0.31	0.097
4	1	0.14	0.36	0.057	4	1	0.14	0.31	0.056
4	2	0.14	0.36	0.076	4	2	0.14	0.31	0.01
4	3	0.14	0.36	0.053	4	3	0.14	0.31	0.041
4	4	0.14	0.36	0.038	4	4	0.14	0.31	0.129
4	5	0.14	0.36	0.032	4	5	0.14	0.31	0.242
4	6	0.14	0.36	0.03	4	6	0.14	0.31	0.148
4	7	0.14	0.36	0.027	4	7	0.14	0.31	0.199
4	8	0.14	0.36	0.021	4	8	0.14	0.31	0.186
4	9	0.14	0.36	0.025	4	9	0.14	0.31	0.048
4	10	0.14	0.36	0.031	4	10	0.14	0.31	0.009
4	11	0.14	0.36	0.036	4	11	0.14	0.31	0.059
4	12	0.14	0.36	0.042	4	12	0.14	0.31	0.097
5	1	0.14	0.36	0.057	5	1	0.14	0.31	0.056
5	2	0.14	0.36	0.076	5	2	0.14	0.31	0.01
5	3	0.14	0.36	0.053	5	3	0.14	0.31	0.041
5	4	0.14	0.36	0.038	5	4	0.14	0.31	0.129
5	5	0.14	0.36	0.032	5	5	0.14	0.31	0.242
5	6	0.14	0.36	0.03	5	6	0.14	0.31	0.148
5	7	0.14	0.36	0.027	5	7	0.14	0.31	0.199

5	8	0.14	0.36	0.021	5	8	0.14	0.31	0.186
5	9	0.14	0.36	0.025	5	9	0.14	0.31	0.048
5	10	0.14	0.36	0.031	5	10	0.14	0.31	0.009
5	11	0.14	0.36	0.036	5	11	0.14	0.31	0.059
5	12	0.14	0.36	0.042	5	12	0.14	0.31	0.097
6	1	0.19	0.45	0.239	6	1	0.17	0.35	0.062
6	2	0.19	0.45	0.234	6	2	0.17	0.35	0.011
6	3	0.19	0.45	0.189	6	3	0.17	0.35	0.054
6	4	0.19	0.45	0.168	6	4	0.17	0.35	0.172
6	5	0.19	0.45	0.118	6	5	0.17	0.35	0.382
6	6	0.19	0.45	0.059	6	6	0.17	0.35	0.275
6	7	0.19	0.45	0.033	6	7	0.17	0.35	0.281
6	8	0.19	0.45	0.028	6	8	0.17	0.35	0.277
6	9	0.19	0.45	0.041	6	9	0.17	0.35	0.059
6	10	0.19	0.45	0.098	6	10	0.17	0.35	0.009
6	11	0.19	0.45	0.18	6	11	0.17	0.35	0.069
6	12	0.19	0.45	0.163	6	12	0.17	0.35	0.108
7	1	0.19	0.45	0.239	7	1	0.17	0.35	0.062
7	2	0.19	0.45	0.234	7	2	0.17	0.35	0.011
7	3	0.19	0.45	0.189	7	3	0.17	0.35	0.054
7	4	0.19	0.45	0.168	7	4	0.17	0.35	0.172
7	5	0.19	0.45	0.118	7	5	0.17	0.35	0.382
7	6	0.19	0.45	0.059	7	6	0.17	0.35	0.275
7	7	0.19	0.45	0.033	7	7	0.17	0.35	0.281
7	8	0.19	0.45	0.028	7	8	0.17	0.35	0.277
7	9	0.19	0.45	0.041	7	9	0.17	0.35	0.059
7	10	0.19	0.45	0.098	7	10	0.17	0.35	0.009
7	11	0.19	0.45	0.18	7	11	0.17	0.35	0.069
7	12	0.19	0.45	0.163	7	12	0.17	0.35	0.108
8	1	0.19	0.45	0.239	8	1	0.17	0.35	0.062
8	2	0.19	0.45	0.234	8	2	0.17	0.35	0.011

8	3	0.19	0.45	0.189	8	3	0.17	0.35	0.054
8	4	0.19	0.45	0.168	8	4	0.17	0.35	0.172
8	5	0.19	0.45	0.118	8	5	0.17	0.35	0.382
8	6	0.19	0.45	0.059	8	6	0.17	0.35	0.275
8	7	0.19	0.45	0.033	8	7	0.17	0.35	0.281
8	8	0.19	0.45	0.028	8	8	0.17	0.35	0.277
8	9	0.19	0.45	0.041	8	9	0.17	0.35	0.059
8	10	0.19	0.45	0.098	8	10	0.17	0.35	0.009
8	11	0.19	0.45	0.18	8	11	0.17	0.35	0.069
8	12	0.19	0.45	0.163	8	12	0.17	0.35	0.108
9	1	0.19	0.71	0.239	9	1	0.17	0.52	0.062
9	2	0.19	0.71	0.231	9	2	0.17	0.52	0.011
9	3	0.19	0.71	0.187	9	3	0.17	0.52	0.054
9	4	0.19	0.71	0.166	9	4	0.17	0.52	0.172
9	5	0.19	0.71	0.111	9	5	0.17	0.52	0.376
9	6	0.19	0.71	0.052	9	6	0.17	0.52	0.269
9	7	0.19	0.71	0.027	9	7	0.17	0.52	0.278
9	8	0.19	0.71	0.022	9	8	0.17	0.52	0.271
9	9	0.19	0.71	0.034	9	9	0.17	0.52	0.059
9	10	0.19	0.71	0.091	9	10	0.17	0.52	0.009
9	11	0.19	0.71	0.18	9	11	0.17	0.52	0.069
9	12	0.19	0.71	0.157	9	12	0.17	0.52	0.108
10	1	0.19	0.71	0.239	10	1	0.17	0.52	0.062
10	2	0.19	0.71	0.231	10	2	0.17	0.52	0.011
10	3	0.19	0.71	0.187	10	3	0.17	0.52	0.054
10	4	0.19	0.71	0.166	10	4	0.17	0.52	0.172
10	5	0.19	0.71	0.111	10	5	0.17	0.52	0.376
10	6	0.19	0.71	0.052	10	6	0.17	0.52	0.269
10	7	0.19	0.71	0.027	10	7	0.17	0.52	0.278
10	8	0.19	0.71	0.022	10	8	0.17	0.52	0.271
10	9	0.19	0.71	0.034	10	9	0.17	0.52	0.059

10	10	0.19	0.71	0.091	10	10	0.17	0.52	0.009
10	11	0.19	0.71	0.18	10	11	0.17	0.52	0.069
10	12	0.19	0.71	0.157	10	12	0.17	0.52	0.108
11	1	0.19	0.71	0.239	11	1	0.17	0.52	0.062
11	2	0.19	0.71	0.231	11	2	0.17	0.52	0.011
11	3	0.19	0.71	0.187	11	3	0.17	0.52	0.054
11	4	0.19	0.71	0.166	11	4	0.17	0.52	0.172
11	5	0.19	0.71	0.111	11	5	0.17	0.52	0.376
11	6	0.19	0.71	0.052	11	6	0.17	0.52	0.269
11	7	0.19	0.71	0.027	11	7	0.17	0.52	0.278
11	8	0.19	0.71	0.022	11	8	0.17	0.52	0.271
11	9	0.19	0.71	0.034	11	9	0.17	0.52	0.059
11	10	0.19	0.71	0.091	11	10	0.17	0.52	0.009
11	11	0.19	0.71	0.18	11	11	0.17	0.52	0.069
11	12	0.19	0.71	0.157	11	12	0.17	0.52	0.108
12	1	0.17	0.72	0.04	12	1	0.16	0.53	0.048
12	2	0.17	0.72	0.054	12	2	0.16	0.53	0.009
12	3	0.17	0.72	0.037	12	3	0.16	0.53	0.036
12	4	0.17	0.72	0.026	12	4	0.16	0.53	0.109
12	5	0.17	0.72	0.022	12	5	0.16	0.53	0.18
12	6	0.17	0.72	0.022	12	6	0.16	0.53	0.123
12	7	0.17	0.72	0.02	12	7	0.16	0.53	0.18
12	8	0.17	0.72	0.014	12	8	0.16	0.53	0.16
12	9	0.17	0.72	0.017	12	9	0.16	0.53	0.045
12	10	0.17	0.72	0.021	12	10	0.16	0.53	0.009
12	11	0.17	0.72	0.024	12	11	0.16	0.53	0.054
12	12	0.17	0.72	0.028	12	12	0.16	0.53	0.085

North American Stainless Airport					North American Stainless Site				
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Surface Roughness**	**Month**	**Sector**	**Albedo**	**Bowen**	**Surface Roughness**

				Length				Ratio	Length
1	1	0.17	0.79	0.047	1	1	0.16	0.75	0.036
1	2	0.17	0.79	0.061	1	2	0.16	0.75	0.023
1	3	0.17	0.79	0.05	1	3	0.16	0.75	0.05
1	4	0.17	0.79	0.044	1	4	0.16	0.75	0.15
1	5	0.17	0.79	0.053	1	5	0.16	0.75	0.209
1	6	0.17	0.79	0.06	1	6	0.16	0.75	0.167
1	7	0.17	0.79	0.056	1	7	0.16	0.75	0.051
1	8	0.17	0.79	0.034	1	8	0.16	0.75	0.023
1	9	0.17	0.79	0.019	1	9	0.16	0.75	0.026
1	10	0.17	0.79	0.055	1	10	0.16	0.75	0.036
1	11	0.17	0.79	0.04	1	11	0.16	0.75	0.017
1	12	0.17	0.79	0.035	1	12	0.16	0.75	0.022
2	1	0.17	0.79	0.047	2	1	0.16	0.75	0.036
2	2	0.17	0.79	0.061	2	2	0.16	0.75	0.023
2	3	0.17	0.79	0.05	2	3	0.16	0.75	0.05
2	4	0.17	0.79	0.044	2	4	0.16	0.75	0.15
2	5	0.17	0.79	0.053	2	5	0.16	0.75	0.209
2	6	0.17	0.79	0.06	2	6	0.16	0.75	0.167
2	7	0.17	0.79	0.056	2	7	0.16	0.75	0.051
2	8	0.17	0.79	0.034	2	8	0.16	0.75	0.023
2	9	0.17	0.79	0.019	2	9	0.16	0.75	0.026
2	10	0.17	0.79	0.055	2	10	0.16	0.75	0.036
2	11	0.17	0.79	0.04	2	11	0.16	0.75	0.017
2	12	0.17	0.79	0.035	2	12	0.16	0.75	0.022
3	1	0.15	0.49	0.055	3	1	0.15	0.48	0.051
3	2	0.15	0.49	0.067	3	2	0.15	0.48	0.034
3	3	0.15	0.49	0.056	3	3	0.15	0.48	0.076
3	4	0.15	0.49	0.051	3	4	0.15	0.48	0.235
3	5	0.15	0.49	0.062	3	5	0.15	0.48	0.316
3	6	0.15	0.49	0.069	3	6	0.15	0.48	0.265
3	7	0.15	0.49	0.067	3	7	0.15	0.48	0.078

3	8	0.15	0.49	0.043	3	8	0.15	0.48	0.035
3	9	0.15	0.49	0.027	3	9	0.15	0.48	0.039
3	10	0.15	0.49	0.077	3	10	0.15	0.48	0.053
3	11	0.15	0.49	0.052	3	11	0.15	0.48	0.023
3	12	0.15	0.49	0.045	3	12	0.15	0.48	0.029
4	1	0.15	0.49	0.055	4	1	0.15	0.48	0.051
4	2	0.15	0.49	0.067	4	2	0.15	0.48	0.034
4	3	0.15	0.49	0.056	4	3	0.15	0.48	0.076
4	4	0.15	0.49	0.051	4	4	0.15	0.48	0.235
4	5	0.15	0.49	0.062	4	5	0.15	0.48	0.316
4	6	0.15	0.49	0.069	4	6	0.15	0.48	0.265
4	7	0.15	0.49	0.067	4	7	0.15	0.48	0.078
4	8	0.15	0.49	0.043	4	8	0.15	0.48	0.035
4	9	0.15	0.49	0.027	4	9	0.15	0.48	0.039
4	10	0.15	0.49	0.077	4	10	0.15	0.48	0.053
4	11	0.15	0.49	0.052	4	11	0.15	0.48	0.023
4	12	0.15	0.49	0.045	4	12	0.15	0.48	0.029
5	1	0.15	0.49	0.055	5	1	0.15	0.48	0.051
5	2	0.15	0.49	0.067	5	2	0.15	0.48	0.034
5	3	0.15	0.49	0.056	5	3	0.15	0.48	0.076
5	4	0.15	0.49	0.051	5	4	0.15	0.48	0.235
5	5	0.15	0.49	0.062	5	5	0.15	0.48	0.316
5	6	0.15	0.49	0.069	5	6	0.15	0.48	0.265
5	7	0.15	0.49	0.067	5	7	0.15	0.48	0.078
5	8	0.15	0.49	0.043	5	8	0.15	0.48	0.035
5	9	0.15	0.49	0.027	5	9	0.15	0.48	0.039
5	10	0.15	0.49	0.077	5	10	0.15	0.48	0.053
5	11	0.15	0.49	0.052	5	11	0.15	0.48	0.023
5	12	0.15	0.49	0.045	5	12	0.15	0.48	0.029
6	1	0.17	0.44	0.061	6	1	0.16	0.34	0.231
6	2	0.17	0.44	0.071	6	2	0.16	0.34	0.212
6	3	0.17	0.44	0.062	6	3	0.16	0.34	0.325

6	4	0.17	0.44	0.057	6	4	0.16	0.34	0.595
6	5	0.17	0.44	0.069	6	5	0.16	0.34	0.69
6	6	0.17	0.44	0.075	6	6	0.16	0.34	0.638
6	7	0.17	0.44	0.076	6	7	0.16	0.34	0.33
6	8	0.17	0.44	0.051	6	8	0.16	0.34	0.217
6	9	0.17	0.44	0.034	6	9	0.16	0.34	0.226
6	10	0.17	0.44	0.109	6	10	0.16	0.34	0.217
6	11	0.17	0.44	0.079	6	11	0.16	0.34	0.07
6	12	0.17	0.44	0.053	6	12	0.16	0.34	0.09
7	1	0.17	0.44	0.061	7	1	0.16	0.34	0.231
7	2	0.17	0.44	0.071	7	2	0.16	0.34	0.212
7	3	0.17	0.44	0.062	7	3	0.16	0.34	0.325
7	4	0.17	0.44	0.057	7	4	0.16	0.34	0.595
7	5	0.17	0.44	0.069	7	5	0.16	0.34	0.69
7	6	0.17	0.44	0.075	7	6	0.16	0.34	0.638
7	7	0.17	0.44	0.076	7	7	0.16	0.34	0.33
7	8	0.17	0.44	0.051	7	8	0.16	0.34	0.217
7	9	0.17	0.44	0.034	7	9	0.16	0.34	0.226
7	10	0.17	0.44	0.109	7	10	0.16	0.34	0.217
7	11	0.17	0.44	0.079	7	11	0.16	0.34	0.07
7	12	0.17	0.44	0.053	7	12	0.16	0.34	0.09
8	1	0.17	0.44	0.061	8	1	0.16	0.34	0.231
8	2	0.17	0.44	0.071	8	2	0.16	0.34	0.212
8	3	0.17	0.44	0.062	8	3	0.16	0.34	0.325
8	4	0.17	0.44	0.057	8	4	0.16	0.34	0.595
8	5	0.17	0.44	0.069	8	5	0.16	0.34	0.69
8	6	0.17	0.44	0.075	8	6	0.16	0.34	0.638
8	7	0.17	0.44	0.076	8	7	0.16	0.34	0.33
8	8	0.17	0.44	0.051	8	8	0.16	0.34	0.217
8	9	0.17	0.44	0.034	8	9	0.16	0.34	0.226
8	10	0.17	0.44	0.109	8	10	0.16	0.34	0.217
8	11	0.17	0.44	0.079	8	11	0.16	0.34	0.07

8	12	0.17	0.44	0.053	8	12	0.16	0.34	0.09
9	1	0.17	0.78	0.055	9	1	0.16	0.75	0.231
9	2	0.17	0.78	0.067	9	2	0.16	0.75	0.212
9	3	0.17	0.78	0.057	9	3	0.16	0.75	0.325
9	4	0.17	0.78	0.051	9	4	0.16	0.75	0.595
9	5	0.17	0.78	0.063	9	5	0.16	0.75	0.69
9	6	0.17	0.78	0.07	9	6	0.16	0.75	0.638
9	7	0.17	0.78	0.069	9	7	0.16	0.75	0.33
9	8	0.17	0.78	0.044	9	8	0.16	0.75	0.217
9	9	0.17	0.78	0.027	9	9	0.16	0.75	0.226
9	10	0.17	0.78	0.096	9	10	0.16	0.75	0.217
9	11	0.17	0.78	0.07	9	11	0.16	0.75	0.07
9	12	0.17	0.78	0.045	9	12	0.16	0.75	0.09
10	1	0.17	0.78	0.055	10	1	0.16	0.75	0.231
10	2	0.17	0.78	0.067	10	2	0.16	0.75	0.212
10	3	0.17	0.78	0.057	10	3	0.16	0.75	0.325
10	4	0.17	0.78	0.051	10	4	0.16	0.75	0.595
10	5	0.17	0.78	0.063	10	5	0.16	0.75	0.69
10	6	0.17	0.78	0.07	10	6	0.16	0.75	0.638
10	7	0.17	0.78	0.069	10	7	0.16	0.75	0.33
10	8	0.17	0.78	0.044	10	8	0.16	0.75	0.217
10	9	0.17	0.78	0.027	10	9	0.16	0.75	0.226
10	10	0.17	0.78	0.096	10	10	0.16	0.75	0.217
10	11	0.17	0.78	0.07	10	11	0.16	0.75	0.07
10	12	0.17	0.78	0.045	10	12	0.16	0.75	0.09
11	1	0.17	0.78	0.055	11	1	0.16	0.75	0.231
11	2	0.17	0.78	0.067	11	2	0.16	0.75	0.212
11	3	0.17	0.78	0.057	11	3	0.16	0.75	0.325
11	4	0.17	0.78	0.051	11	4	0.16	0.75	0.595
11	5	0.17	0.78	0.063	11	5	0.16	0.75	0.69
11	6	0.17	0.78	0.07	11	6	0.16	0.75	0.638
11	7	0.17	0.78	0.069	11	7	0.16	0.75	0.33

11	8	0.17	0.78	0.044	11	8	0.16	0.75	0.217
11	9	0.17	0.78	0.027	11	9	0.16	0.75	0.226
11	10	0.17	0.78	0.096	11	10	0.16	0.75	0.217
11	11	0.17	0.78	0.07	11	11	0.16	0.75	0.07
11	12	0.17	0.78	0.045	11	12	0.16	0.75	0.09
12	1	0.17	0.79	0.047	12	1	0.16	0.75	0.036
12	2	0.17	0.79	0.061	12	2	0.16	0.75	0.023
12	3	0.17	0.79	0.05	12	3	0.16	0.75	0.05
12	4	0.17	0.79	0.044	12	4	0.16	0.75	0.15
12	5	0.17	0.79	0.053	12	5	0.16	0.75	0.209
12	6	0.17	0.79	0.06	12	6	0.16	0.75	0.167
12	7	0.17	0.79	0.056	12	7	0.16	0.75	0.051
12	8	0.17	0.79	0.034	12	8	0.16	0.75	0.023
12	9	0.17	0.79	0.019	12	9	0.16	0.75	0.026
12	10	0.17	0.79	0.055	12	10	0.16	0.75	0.036
12	11	0.17	0.79	0.04	12	11	0.16	0.75	0.017
12	12	0.17	0.79	0.035	12	12	0.16	0.75	0.022

Appendix C. Lead Emission Sources

Facility	Source ID	X Coord. [m]	Y Coord. [m]	Base Elevation [m]	Release Height [m]	Emission Rate [g/s]	Gas Exit Temperature [K]	Gas Exit Velocity [m/s]	Inside Diameter [m]	Description
Big Sandy	COMB01	358314.98	4226074.65	1.75E+02	250.85	0.126	429.82	29.87	8.595	Unit 1Boiler- Coal Use
	COMB02	358314.98	4226074.28	1.75E+02	250.85	0.126	429.82	29.87	8.595	Unit 2 Boiler-Coal Use
	COMB04	358357.69	4226142.21	1.75E+02	31.09	0.126	659.26	17.983	2.103	Aux. Unit 2 Boiler
Calgon Carbon	045	361167.00	4244297.94	168.08	29.87	0.1744	435.93	18.288	0.853	Reactivation Furnance
Enersys	001	738518	4179618	302.04	17.07	8.97E-05	322.04	17.678	1.524	Grid Casting baghouse (4 total)
	002	738627	4179511	300.6	13.41	0.0001945	299.82	20.726	1.524	Assembly Baghouse (4 total)
	003	738632	4179534	305.25	13.41	0.0001207	299.82	21.031	1.067	Plate Finishing Baghouse (2 total)
	004	738543	4179577	302.16	15.85	0.001701	299.82	25.908	0.61	Iron Clad Filling Baghouse
	005	738545	4179581	302.28	15.85	0.001189	299.82	19.507	0.61	Iron Clad Filling Baghouse
	006	738542	4179573	302.08	15.85	0.01298	299.82	19.507	0.701	Iron Clad Filling Baghouse
	011	738532	4179615	302.32	18.29	9.65E-05	355.37	11.582	0.366	Lead Oxide Mill #1 Baghouse
	021	738538	4179614	302.48	18.29	0.04423	355.37	14.326	0.366	Lead Oxide Mill #2 Baghouse
	024	738636	4179538	306.19	12.19	1.74E-05	299.82	23.774	1.006	Assembly Baghouse
	025	738508	4179616	301.75	12.19	5.54E-05	299.82	17.678	1.433	Pasting Baghouse
	031	738535	4179614	302.39	18.29	3.97E-05	355.37	26.822	0.366	Lead Oxide Mill #3 Baghouse
North American Stainless	S1	666748.47	4287588.65	147.5	64.92	1.40E-09	313.15	21.92	1.219	Natural Gas - Boiler
	S2	666776.71	4287551	147.46	64.92	0.0328	408.15	19.48	4.572	Natural Gas Boiler/Furnace
	S3	667246.62	4287783.1	148.98	29.87	9.75E-06	477.59	10.24	0.914	Furnace
	S4	667027.48	4287593.63	149.29	49.99	3.02E-06	477.59	4.02	1.999	Furnace
Newpage	COMB5009	314777.41	4090785.83	105.78	71.32	1.75E-01	449.82	17.556	2.713	Bark/Combination Boiler
	008	314893.44	4090844.76	109.01	24.38	5.75E-03	349.82	9.144	1.753	Lime Kiln

Superior Battery	PBO1	678882.78	4104156.63	309.88	15.54	6.33E-06	407.04	7.925	0.381	Oxide Mill 1
	PBO2	678888.02	4104159.91	309.75	15.54	6.12E-06	379.82	7.925	0.381	Oxide Mill 2
	C1	678849.23	4104100.07	310.38	13.41	0.0007216	317.04	14.021	1.219	Grid Casting Operation
	P1	678840.57	4104179.77	313.03	13.41	0.0001385	338.71	9.754	1.524	Pasting Operation
	3P_AB	678797	4104154	314.49	13.11	0.002087	310.93	7.01	1.829	3 Process Operation a&b Lines
	3P_C	678839.45	4104378.74	313.99	12.19	0.03577	310.93	10.668	1.067	3 Process Operation c Lines
	SP_1	678835.72	4104354.56	314.41	7.62	4.32E-08	310.93	14.021	2.53	Smalls Parts Casting
	SP_2	678851.22	4104354.37	314.47	6.1	5.75E-10	310.93	14.021	0.253	Battery Cable Manufacturing
TVA Shawnee	STCK1	342436.92	4113016.64	94.71	243.84	0.1211	429.82	29.428	8.534	Units 1-5
	STCK2	342087.82	4113168.96	95.89	243.84	0.1211	422.04	29.632	8.53	Units 6-10

Appendix D

Figure 1. Big Sandy-Airport, High 1st High Monthly Average Concentration, Entire Domain

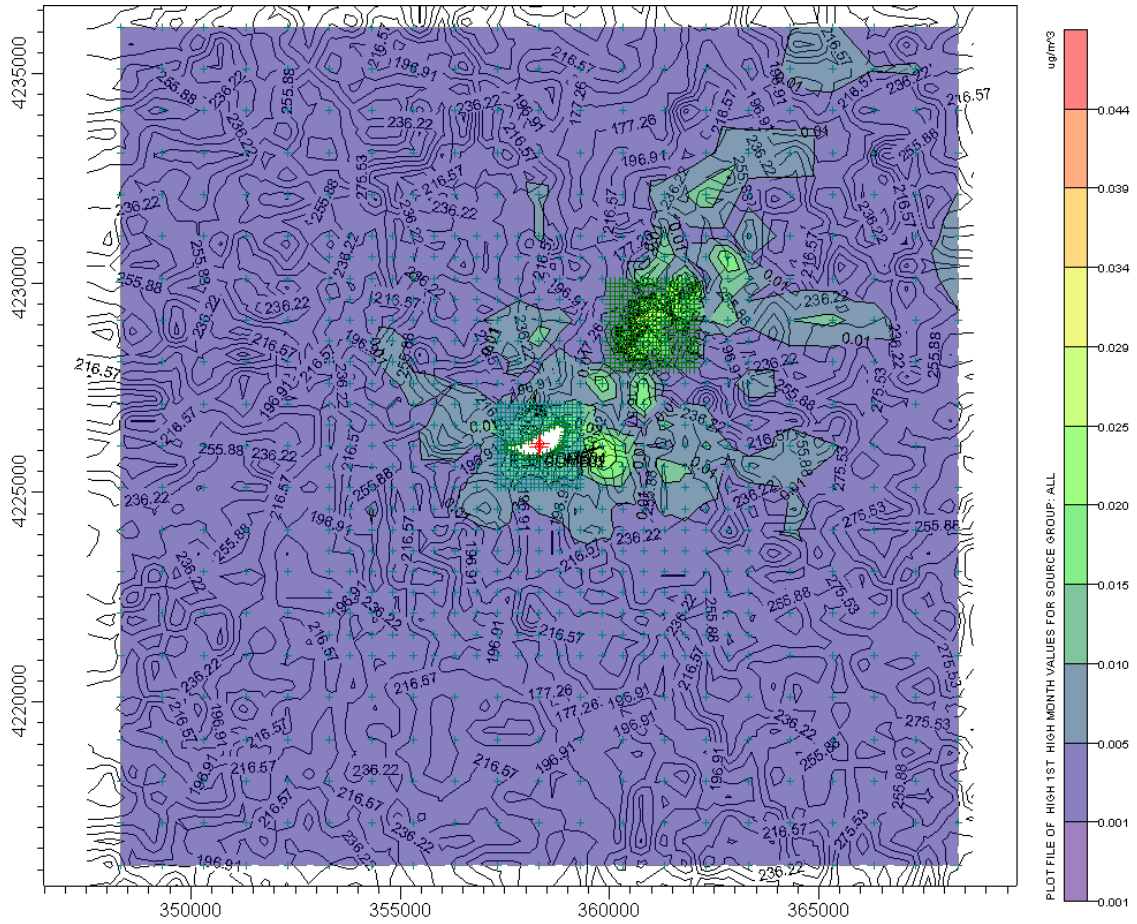


Figure 1.1 Big Sandy-Airport, High 1st High Monthly Average Concentration, Controlling Concentration

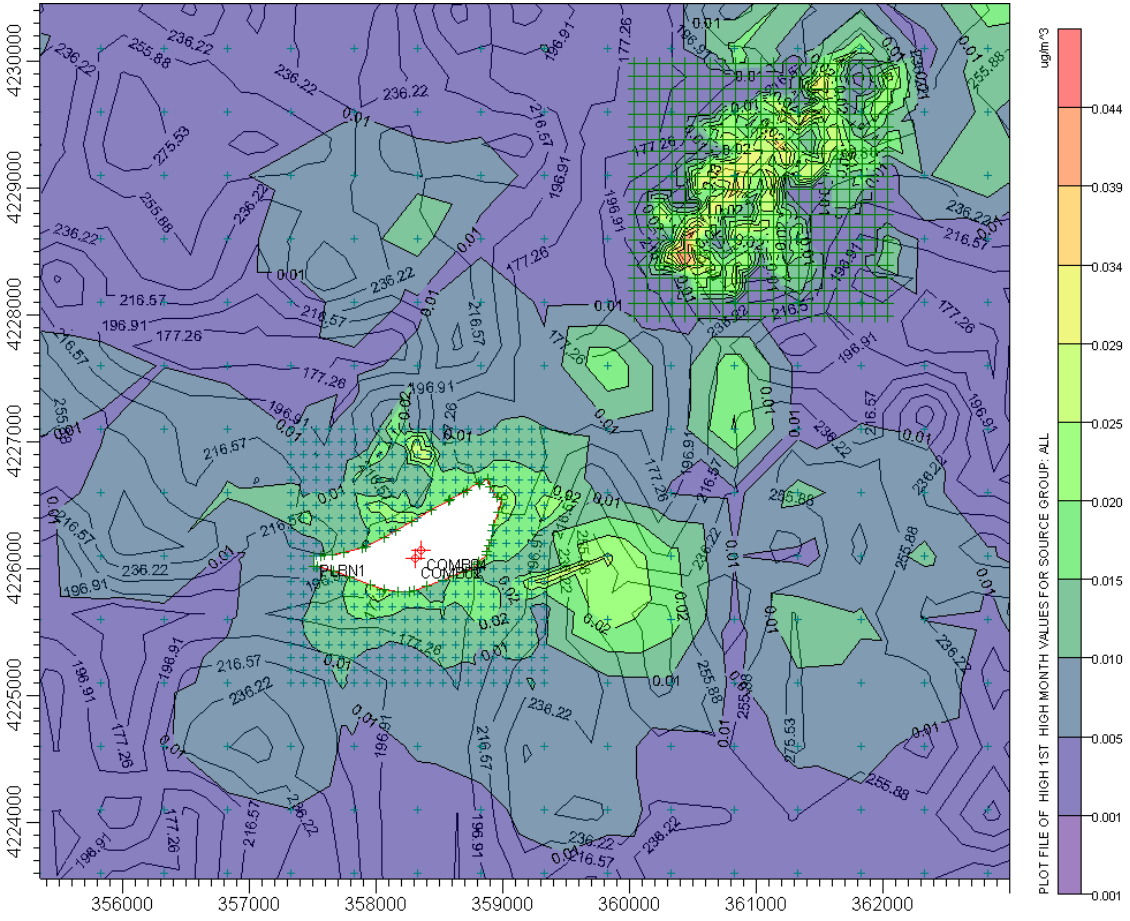


Figure 2. Big Sandy-Site, High 1st High Monthly Average Concentration, Entire Domain

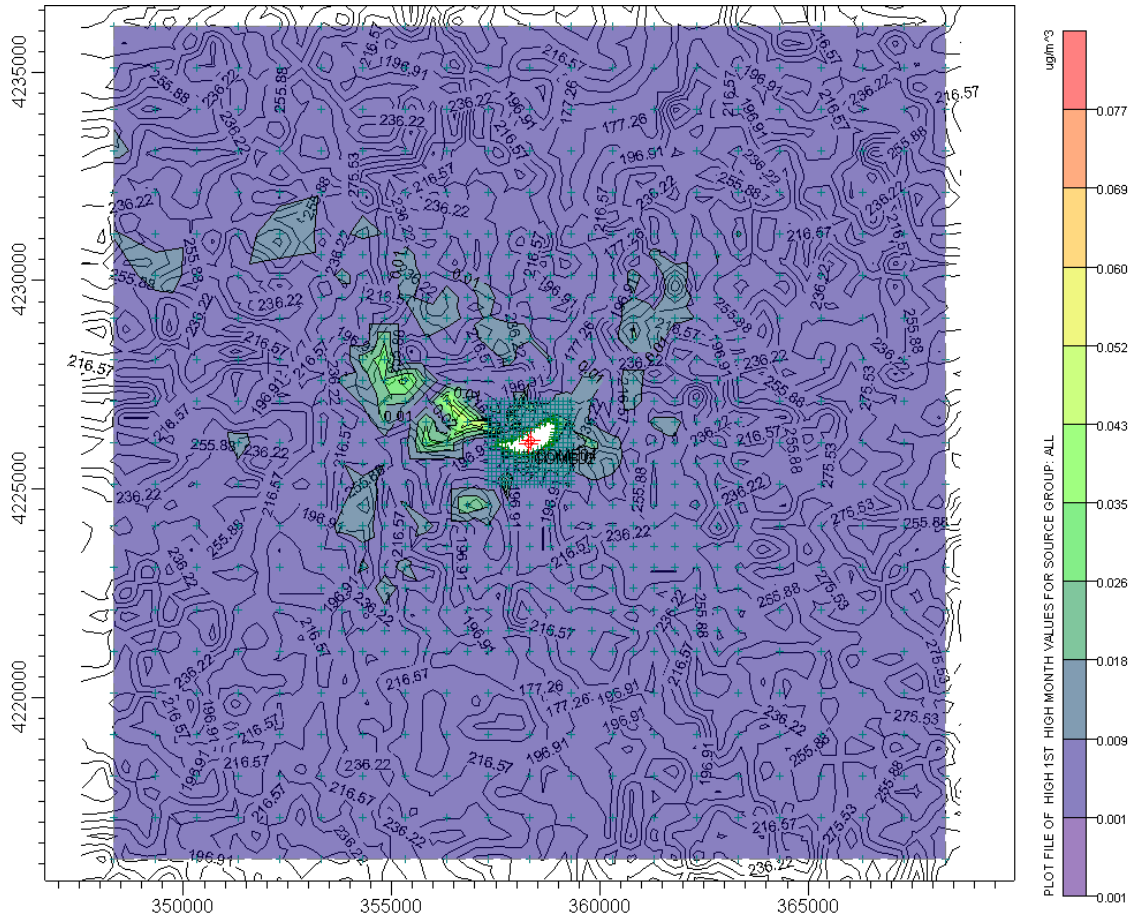


Figure 2.1 Big Sandy-Site, High 1st High Monthly Average Concentration, Controlling Concentration

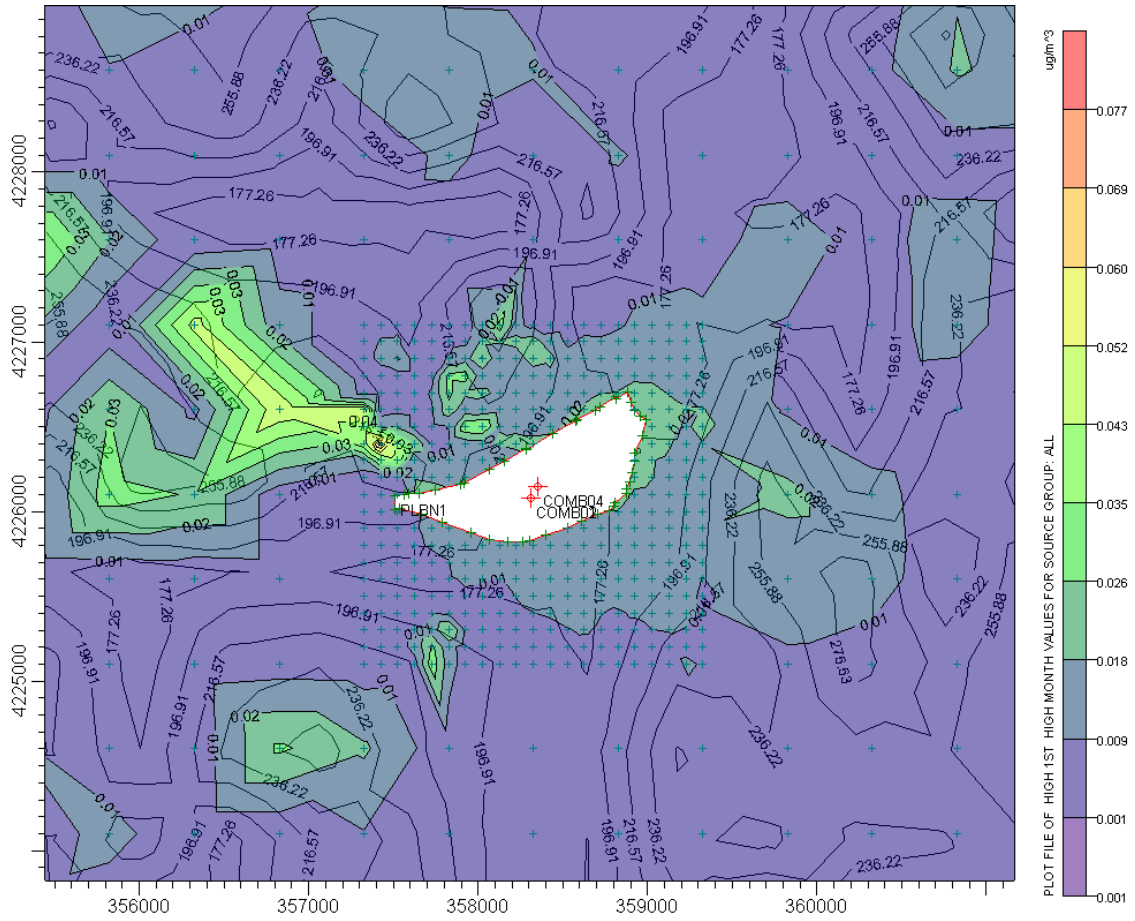


Figure 3. Calgon Carbon-Airport, High 1st High Monthly Average Concentration, Entire Domain

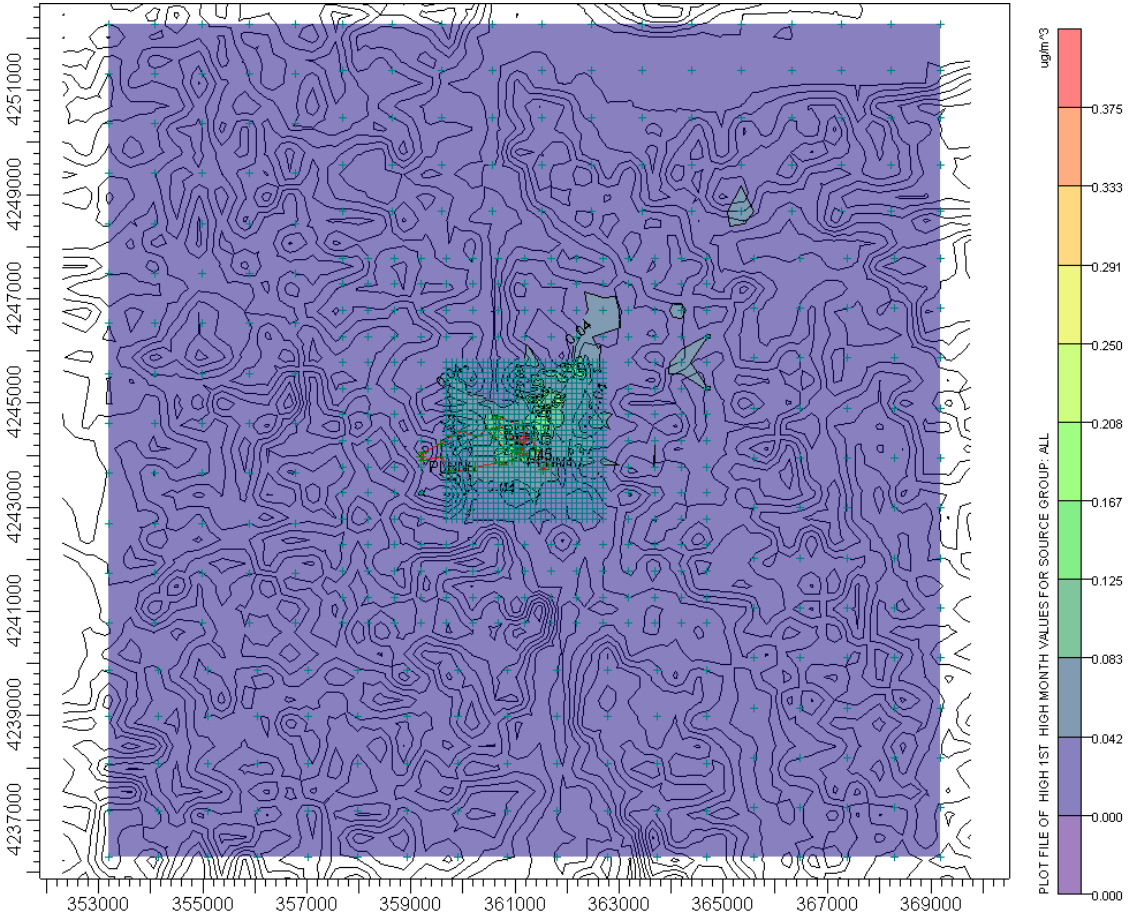


Figure 3.1 Calgon Carbon-Airport, High 1st High Monthly Average Concentration, Controlling Concentration

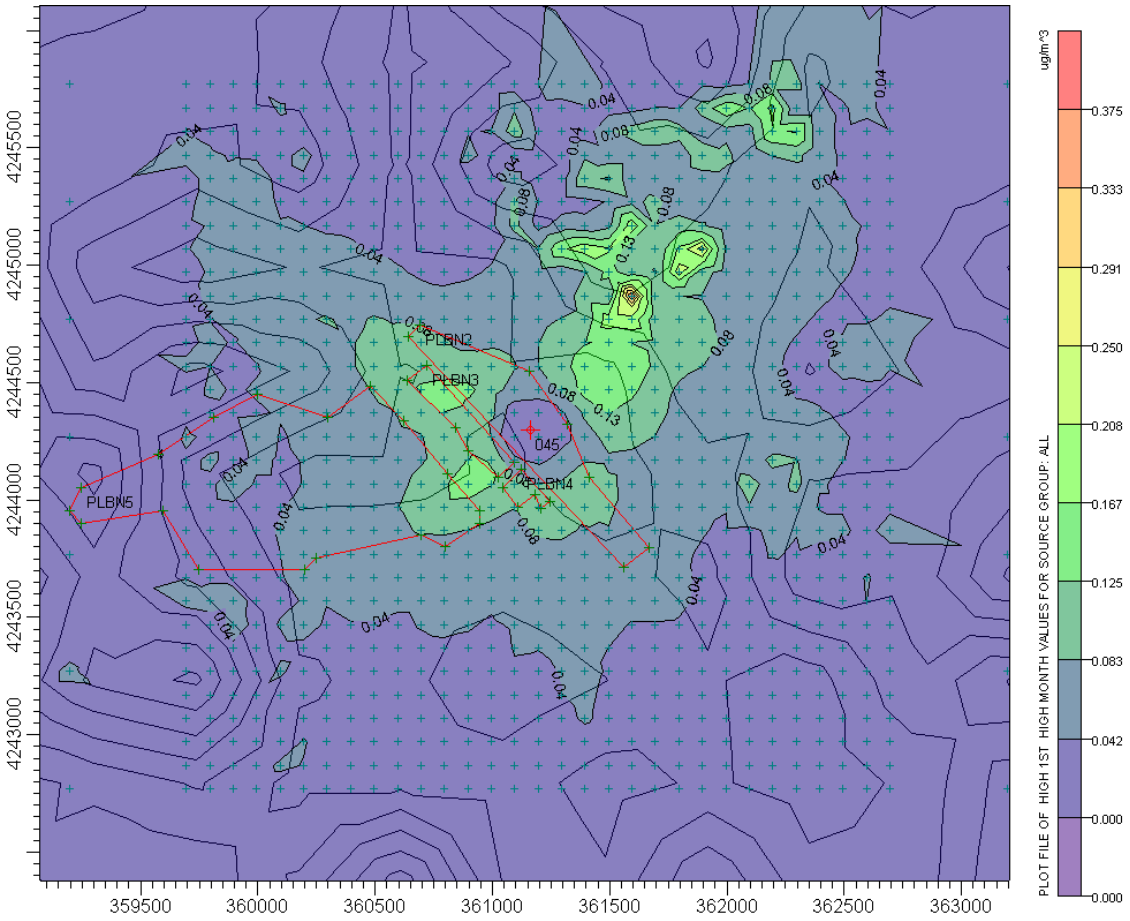


Figure 4. Calgon Carbon-Site, High 1st High Monthly Average Concentration, Entire Domain

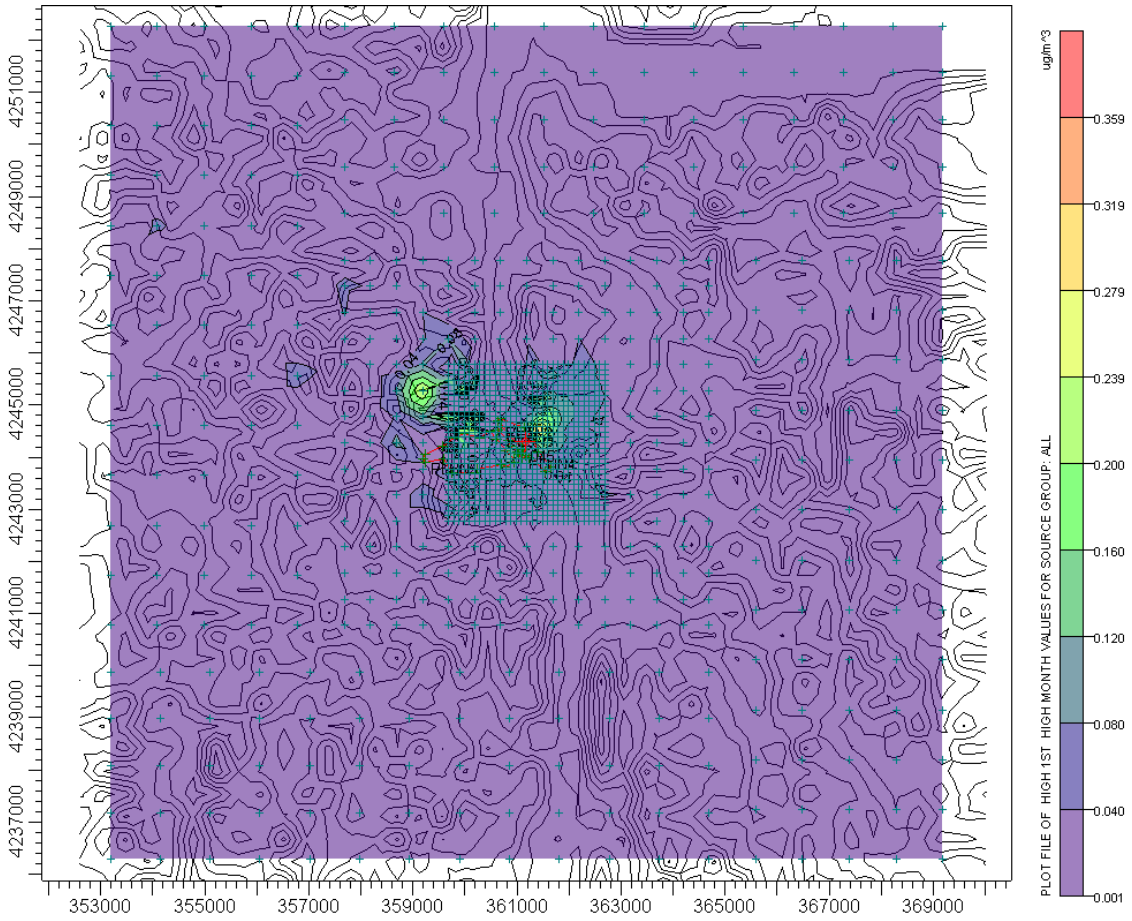


Figure 4.1 Calgon Carbon-Site, High 1st High Monthly Average Concentration, Controlling Concentration

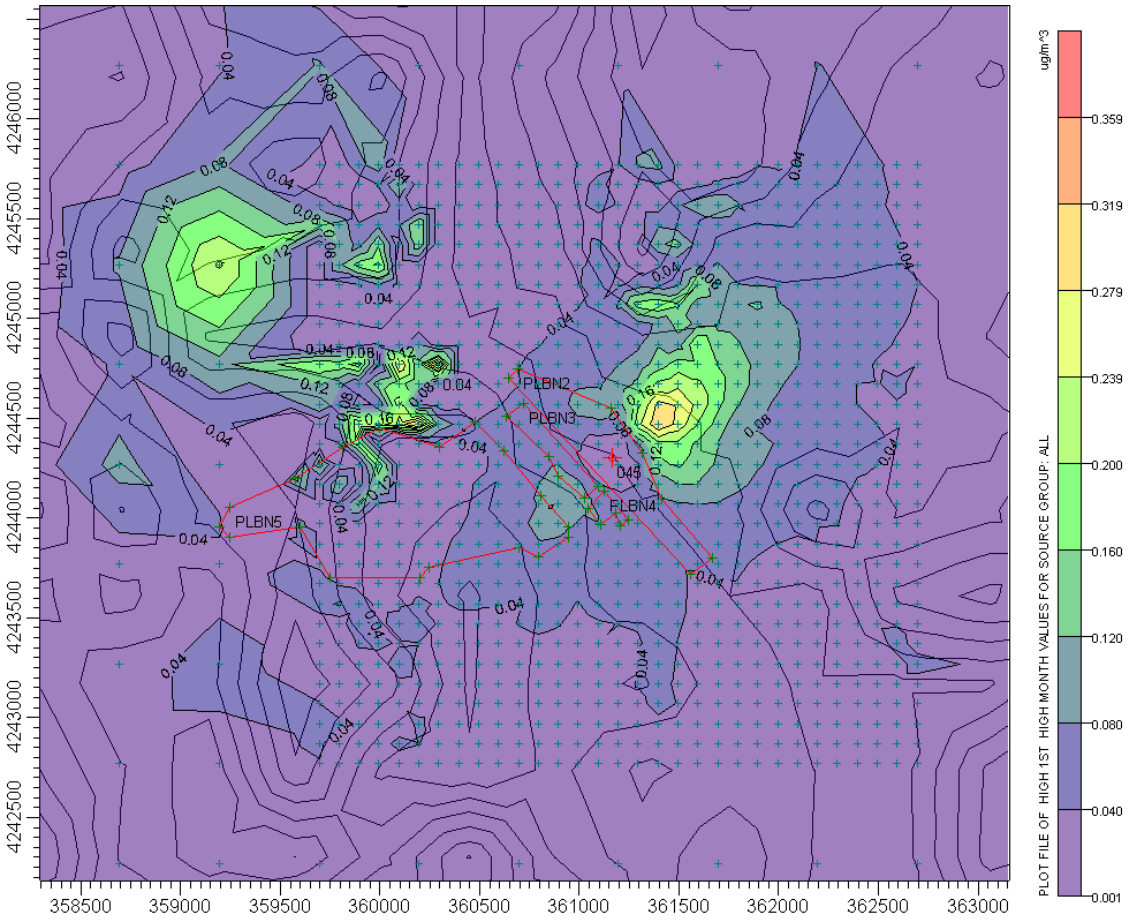


Figure 5. Enersys-Airport, High 1st High Monthly Average Concentration, Entire Domain

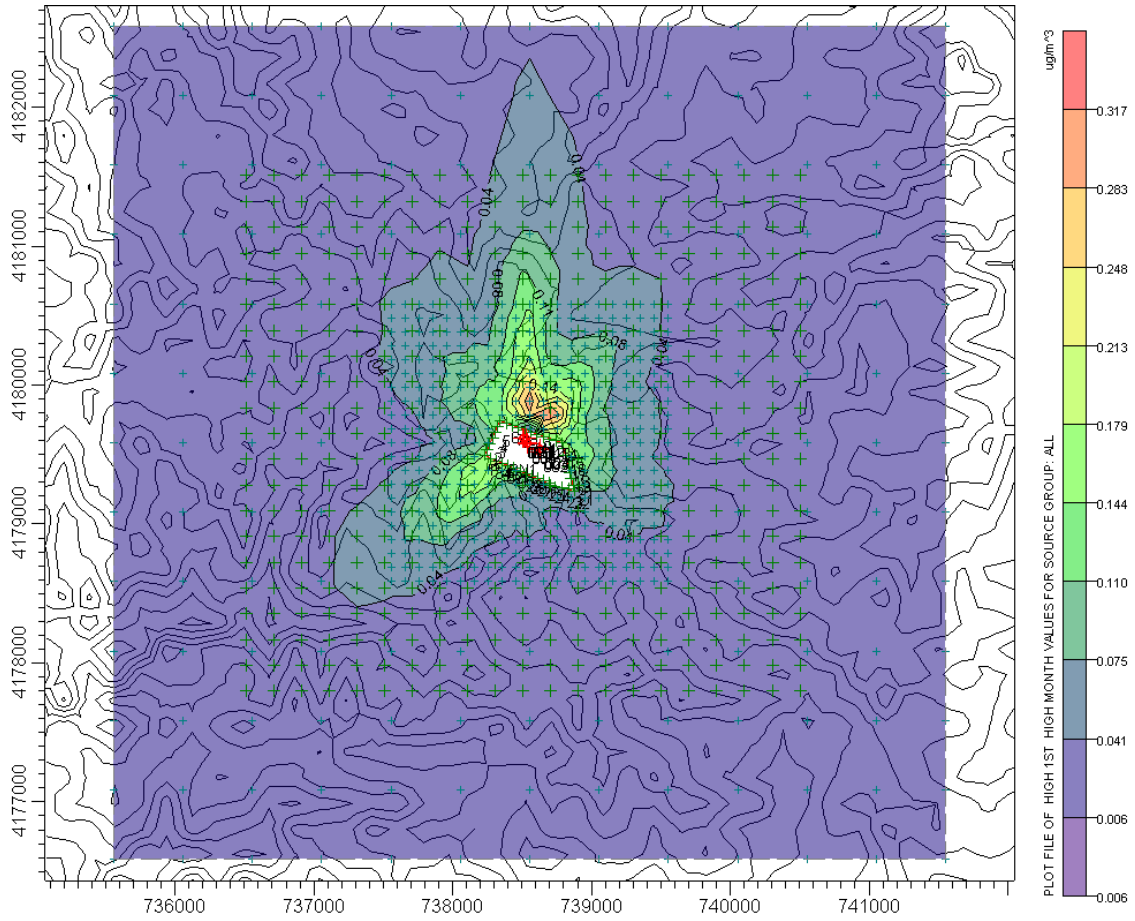


Figure 5.1 Enersys-Airport, High 1st High Monthly Average Concentration, Controlling Concentration

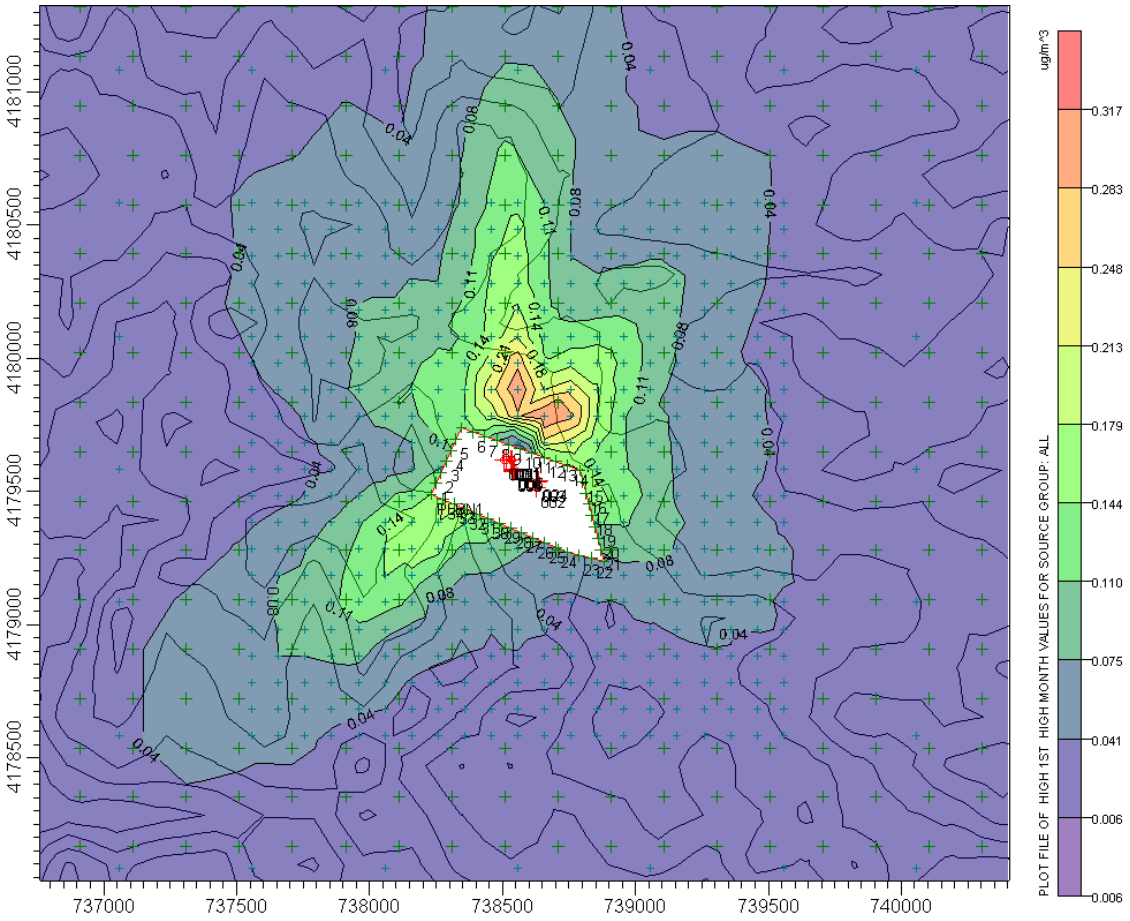


Figure 6. Enersys -Site, High 1st High Monthly Average Concentration, Entire Domain

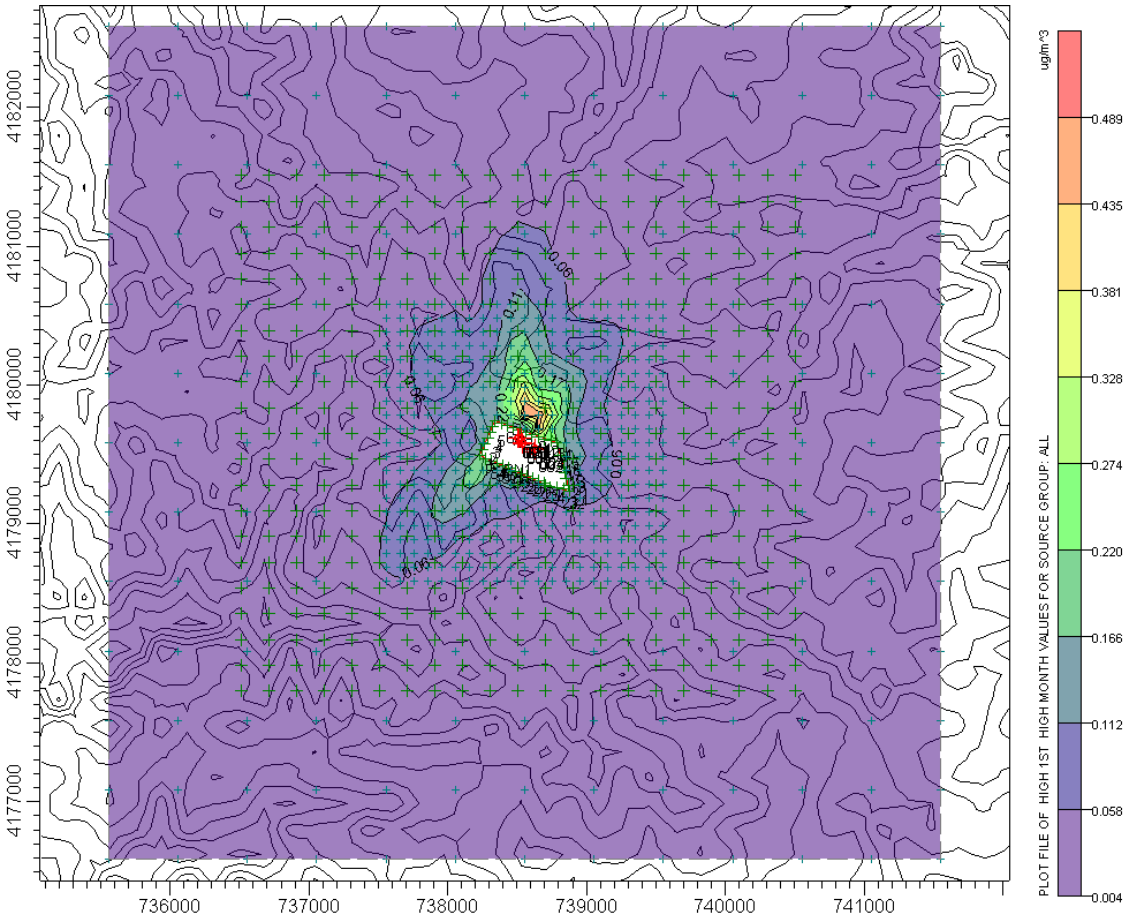


Figure 6.1 Enersys -Site, High 1st High Monthly Average Concentration, Controlling Concentration

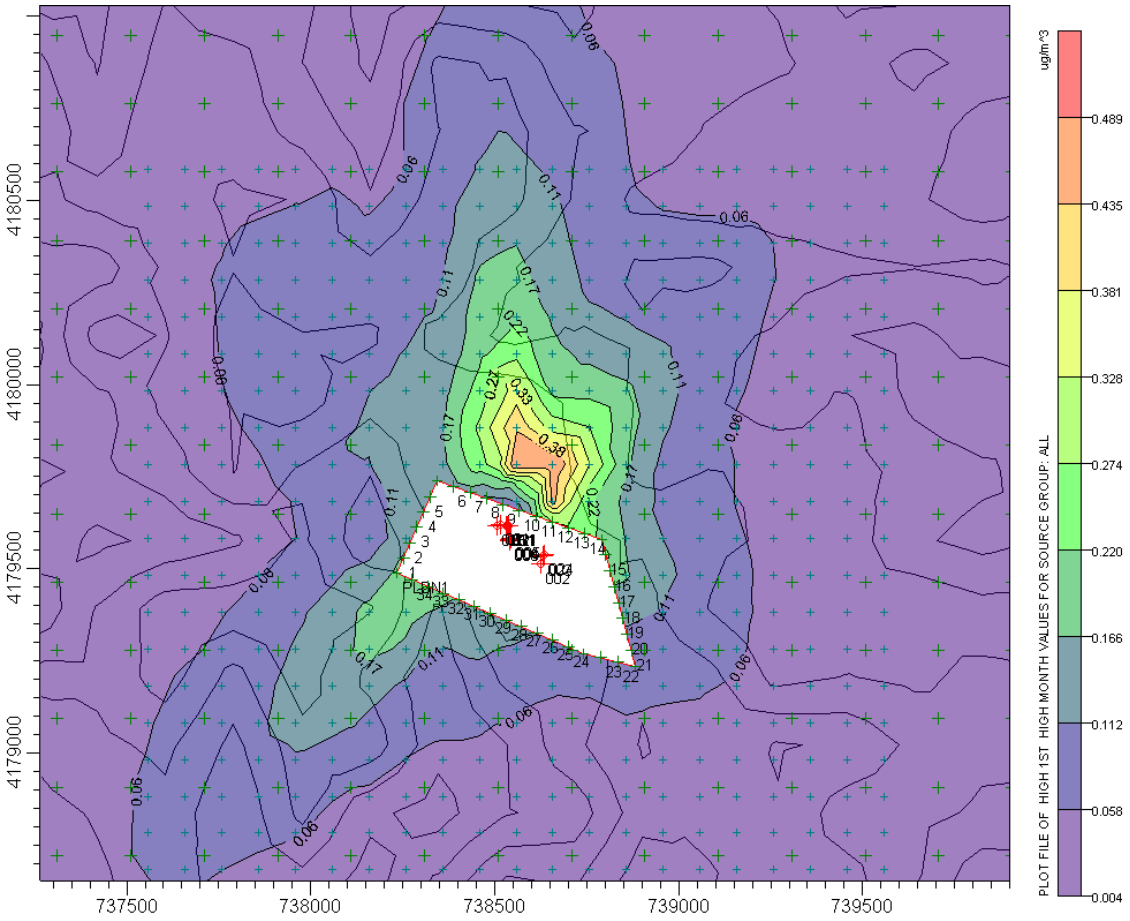


Figure 7. North American Stainless-Airport, High 1st High Monthly Average Concentration, Entire Domain

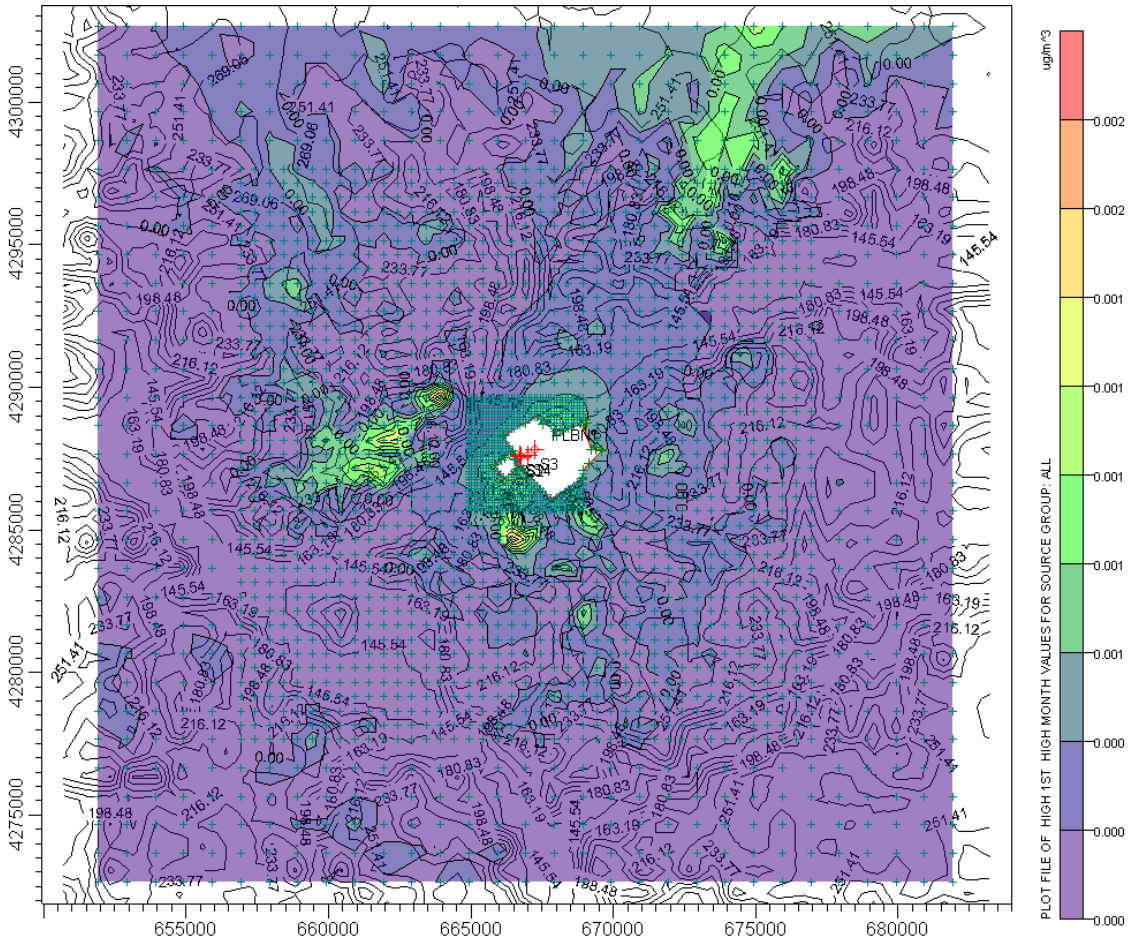


Figure 7.1 North American Stainless -Airport, High 1st High Monthly Average Concentration, Controlling Concentration

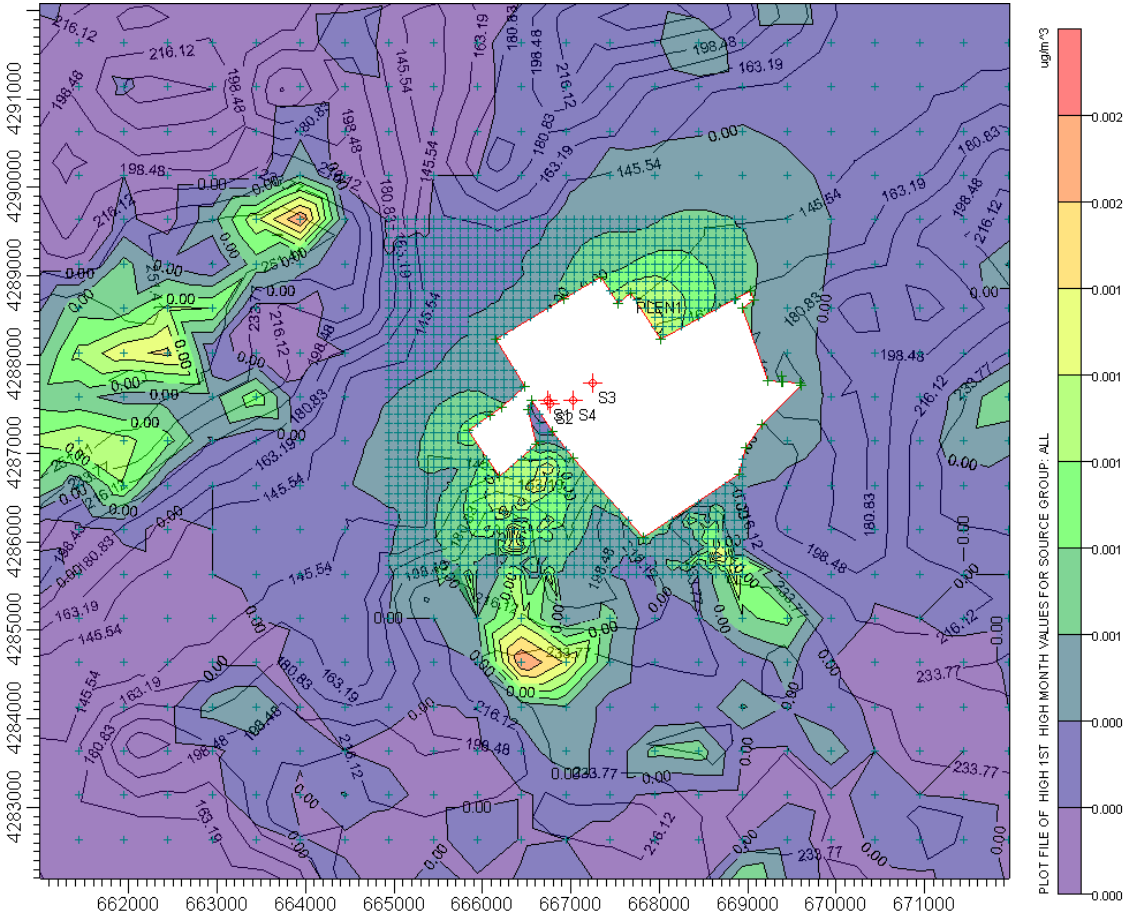


Figure 8. North American Stainless -Site, High 1st High Monthly Average Concentration, Entire Domain

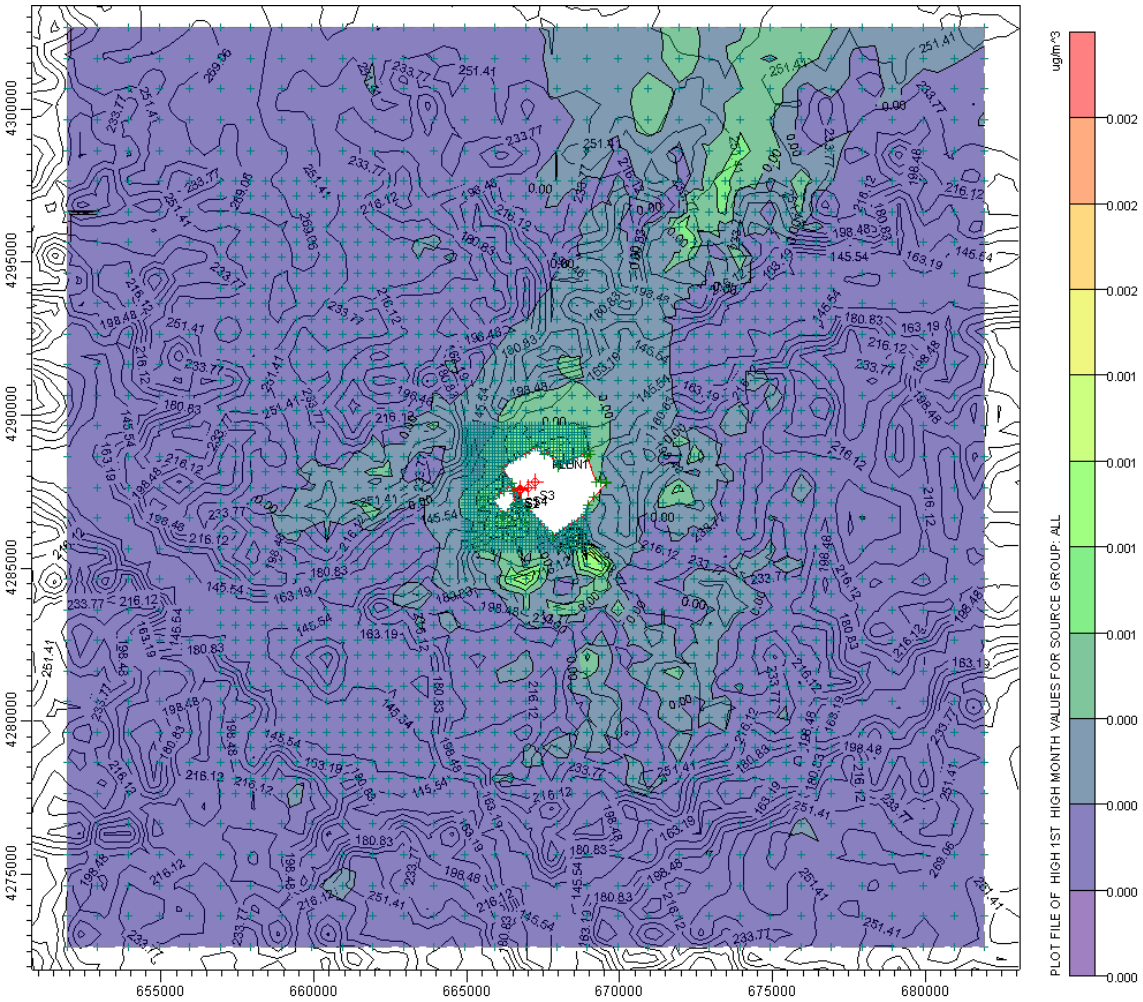


Figure 8.1 North American Stainless -Site, High 1st High Monthly Average Concentration, Controlling Concentration

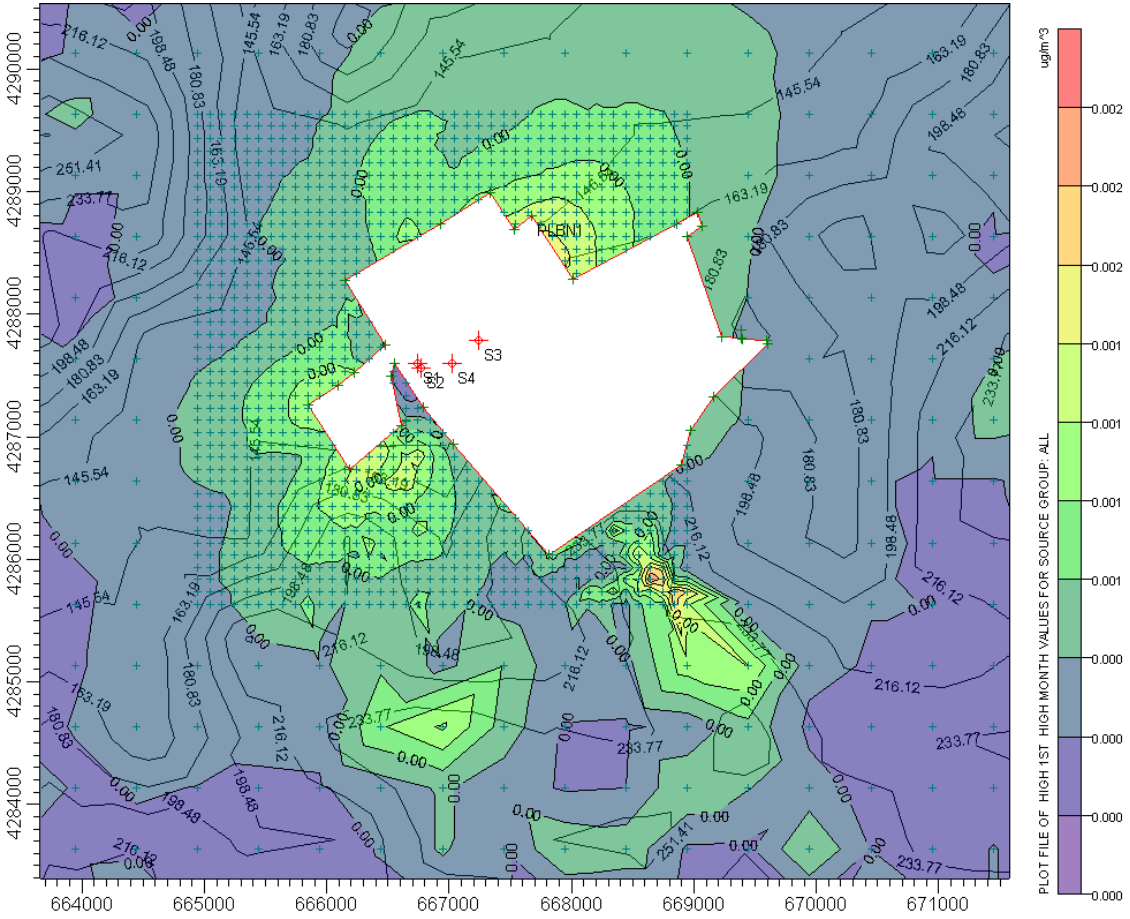


Figure 9. Newpage-Airport, High 1st High Monthly Average Concentration, Entire Domain

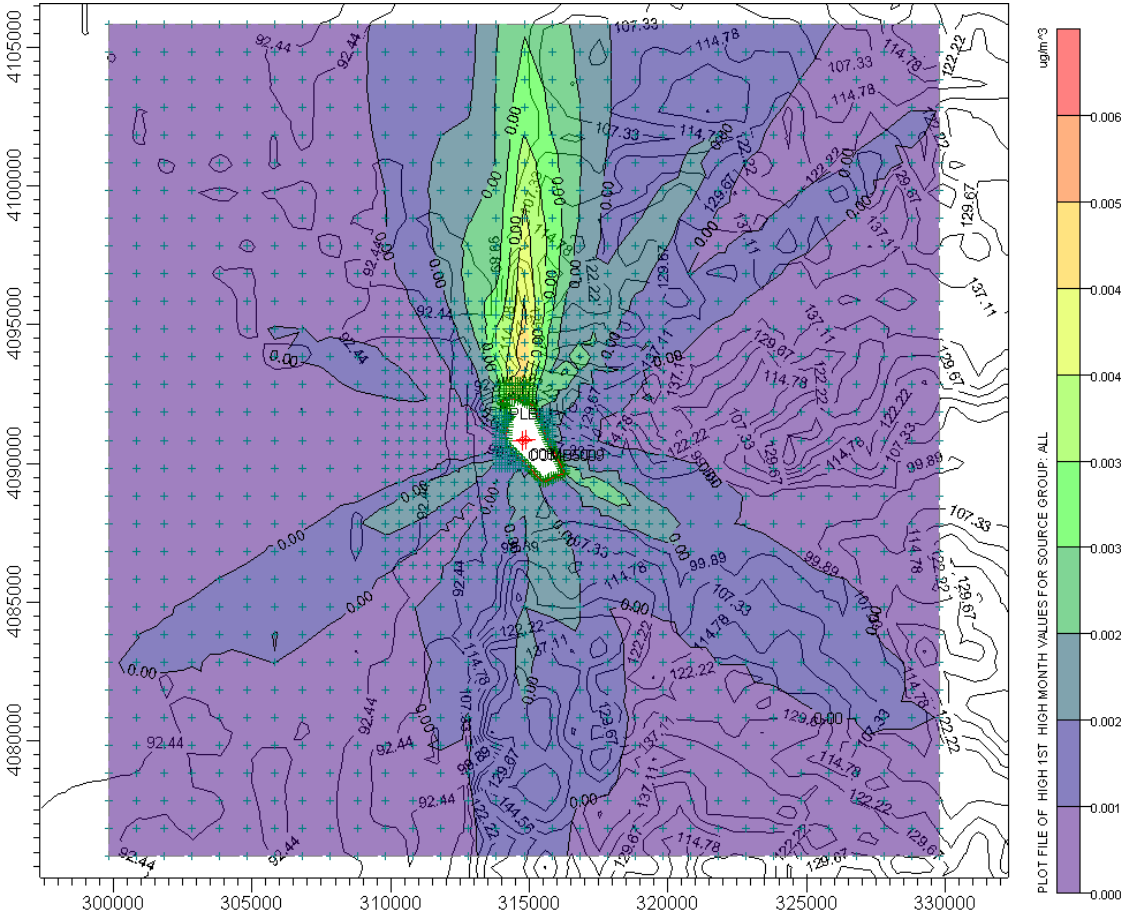


Figure 9.1 Newpage-Airport, High 1st High Monthly Average Concentration, Controlling Concentration

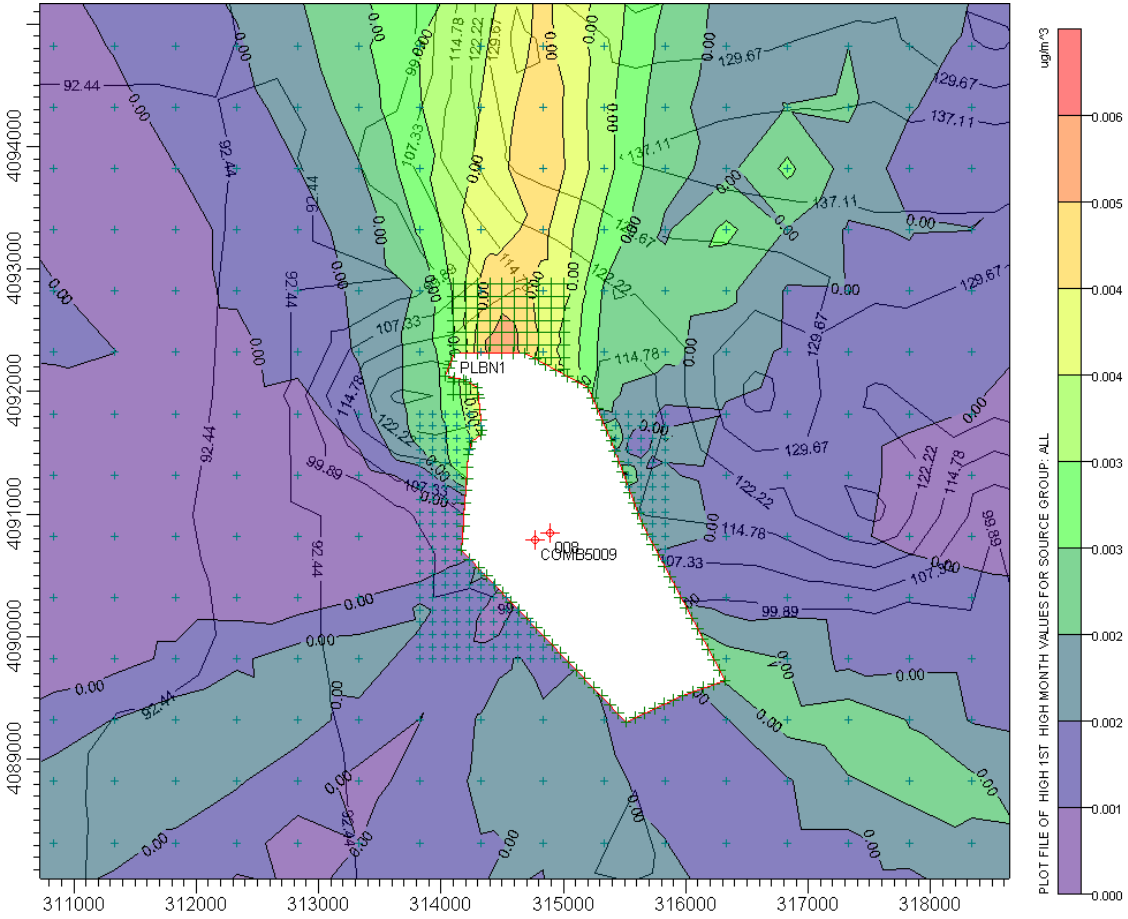


Figure 10. Newpage -Site, High 1st High Monthly Average Concentration, Entire Domain

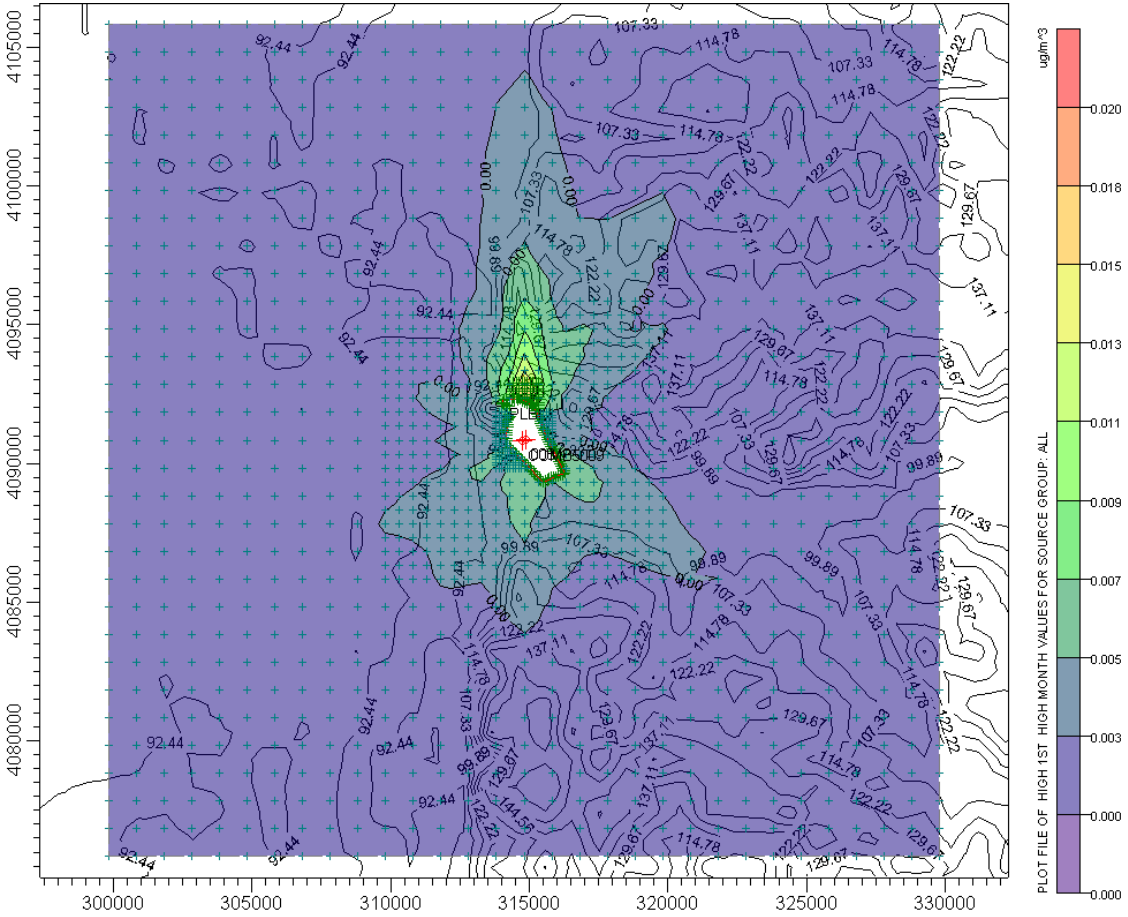


Figure 10.1 Newpage -Site, High 1st High Monthly Average Concentration, Controlling Concentration

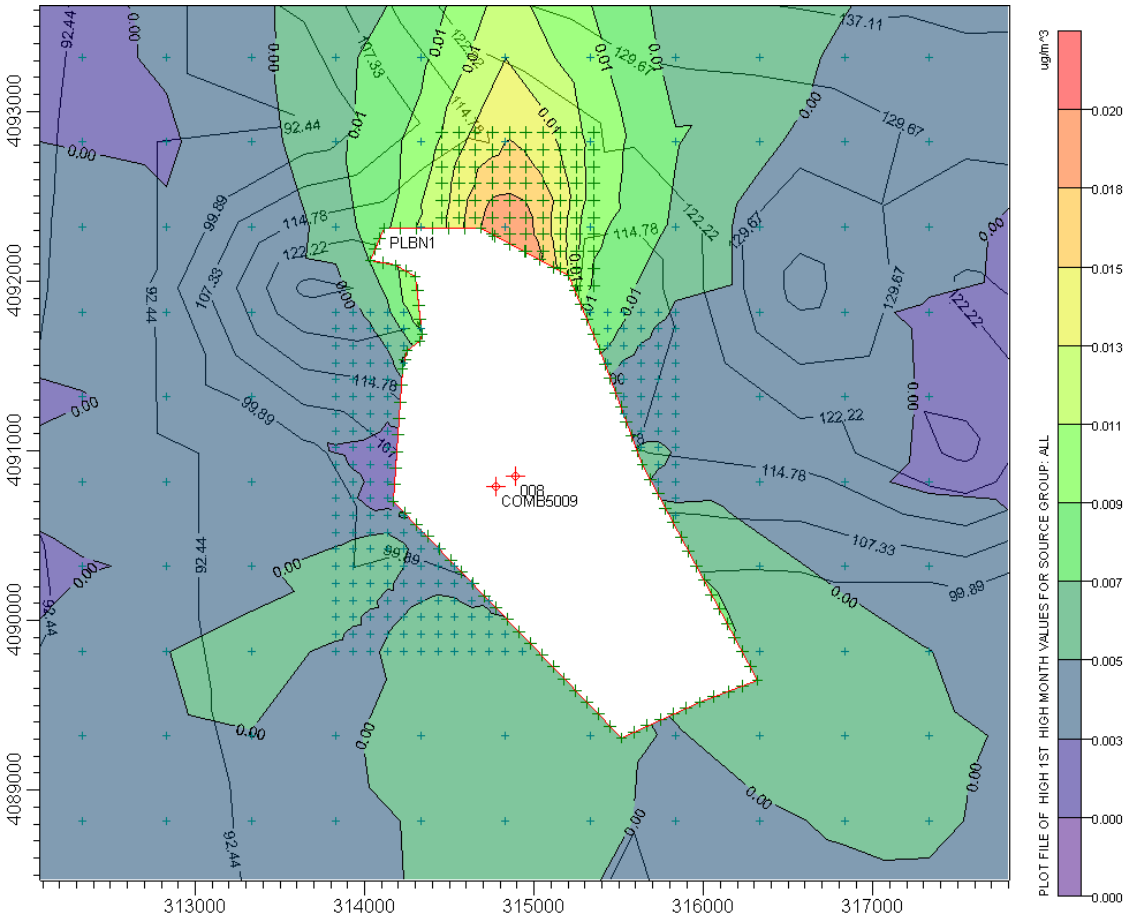


Figure 11. Superior Battery-Airport, High 1st High Monthly Average Concentration, Entire Domain

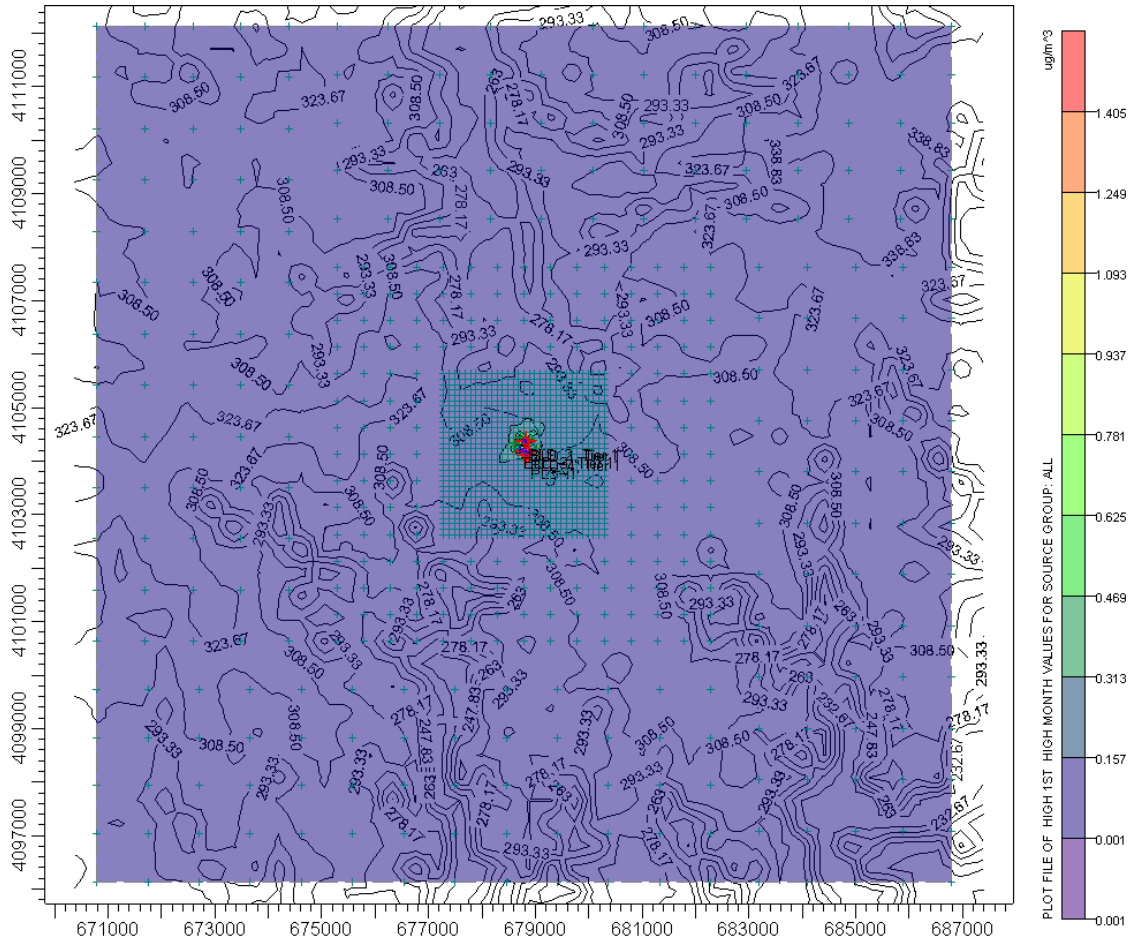


Figure 11.1 Superior Battery-Airport, High 1st High Monthly Average Concentration, Controlling Concentration

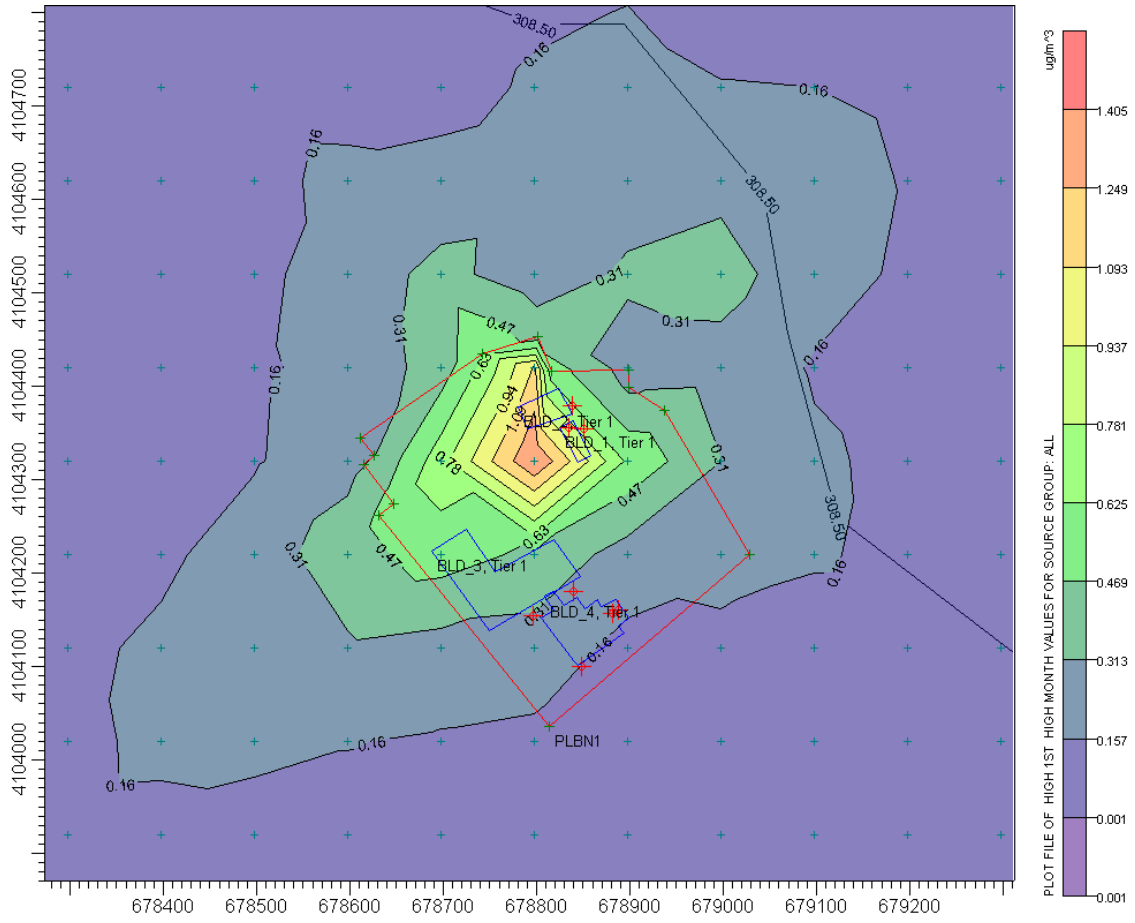


Figure 12. Superior Battery-Site, High 1st High Monthly Average Concentration, Entire Domain

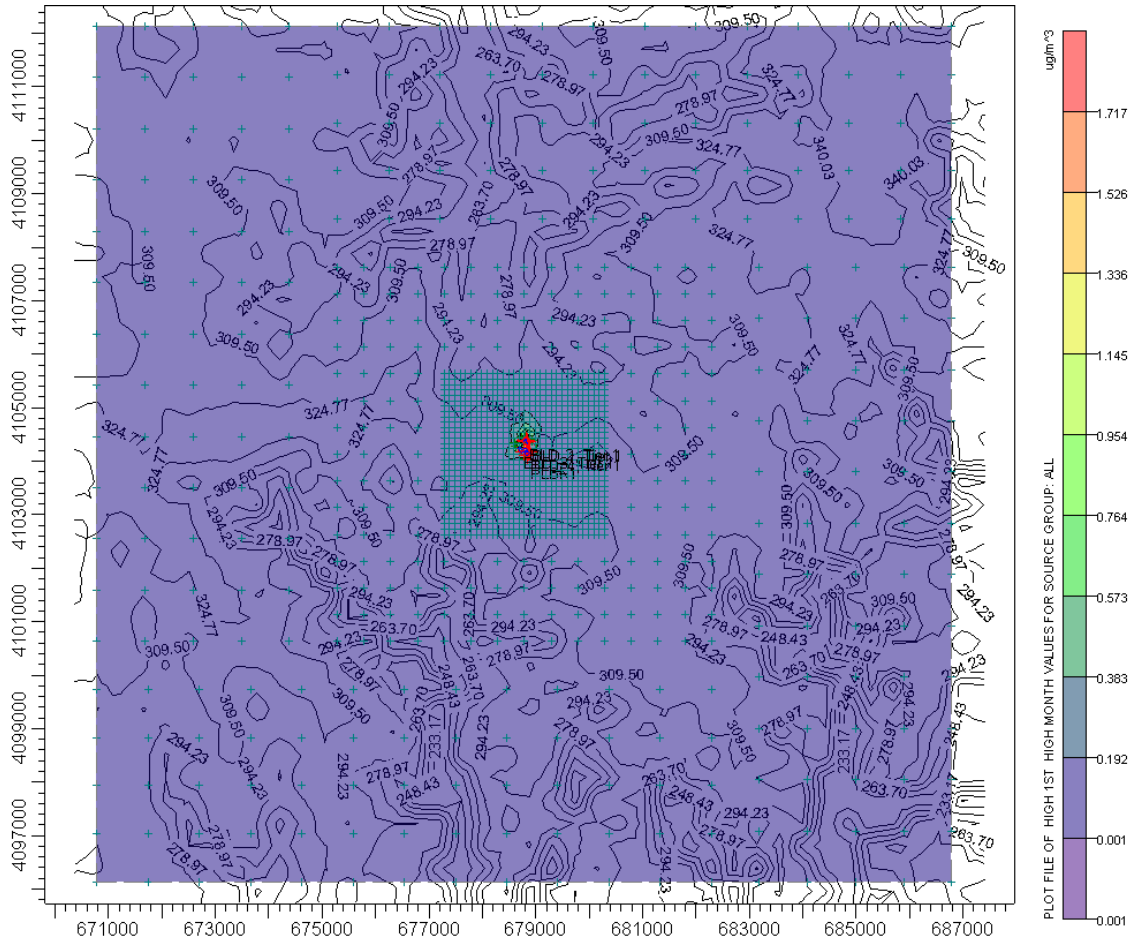


Figure 12.1 Superior Battery-Site, High 1st High Monthly Average Concentration, Controlling Concentration

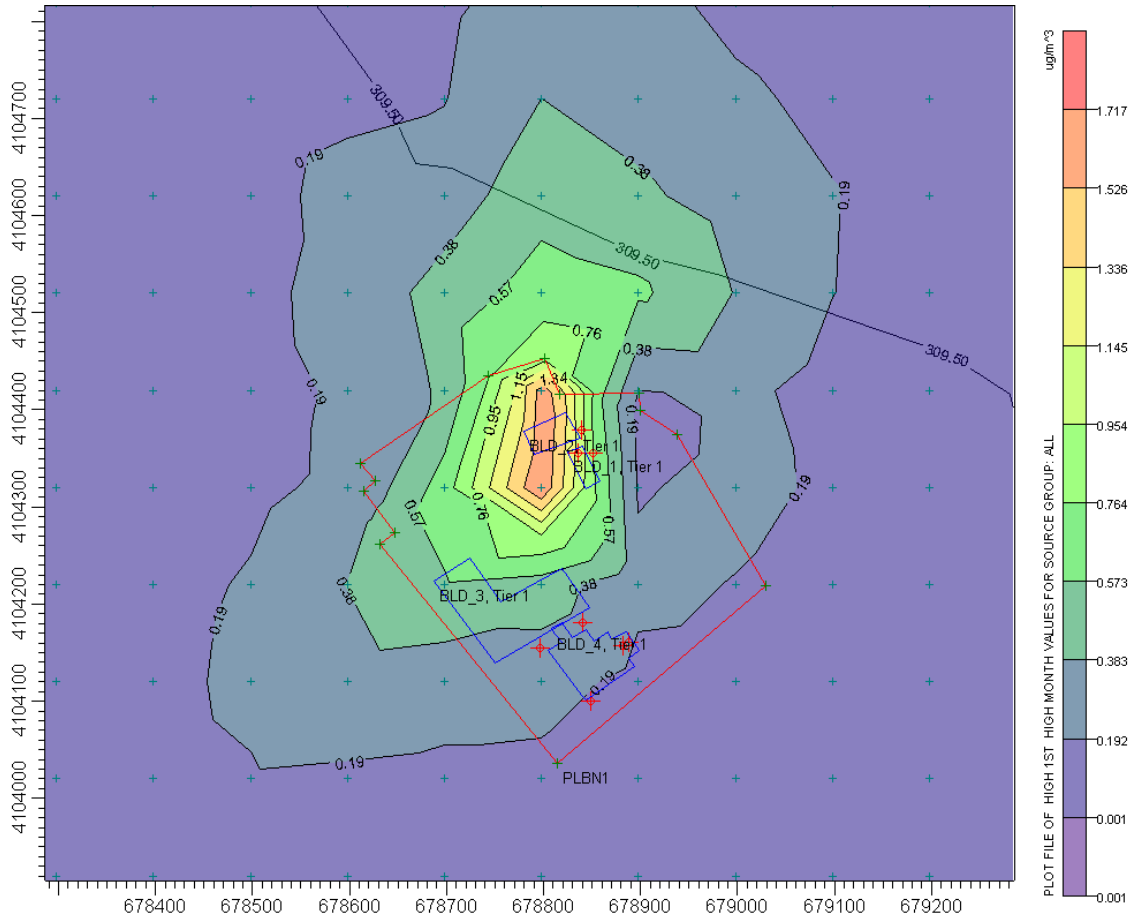


Figure 13. TVA-Airport, High 1st High Monthly Average Concentration, Entire Domain

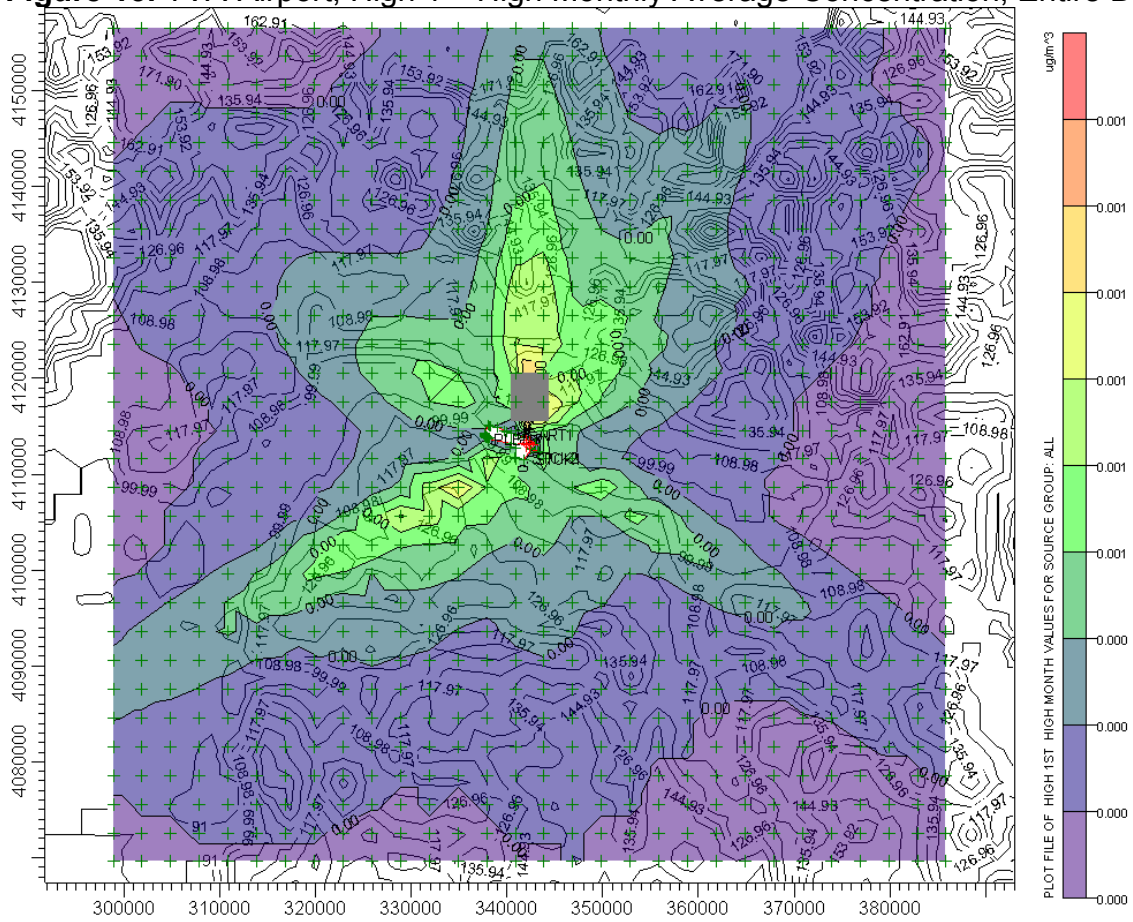


Figure 13.1 TVA-Airport, High 1st High Monthly Average Concentration, Controlling Concentration

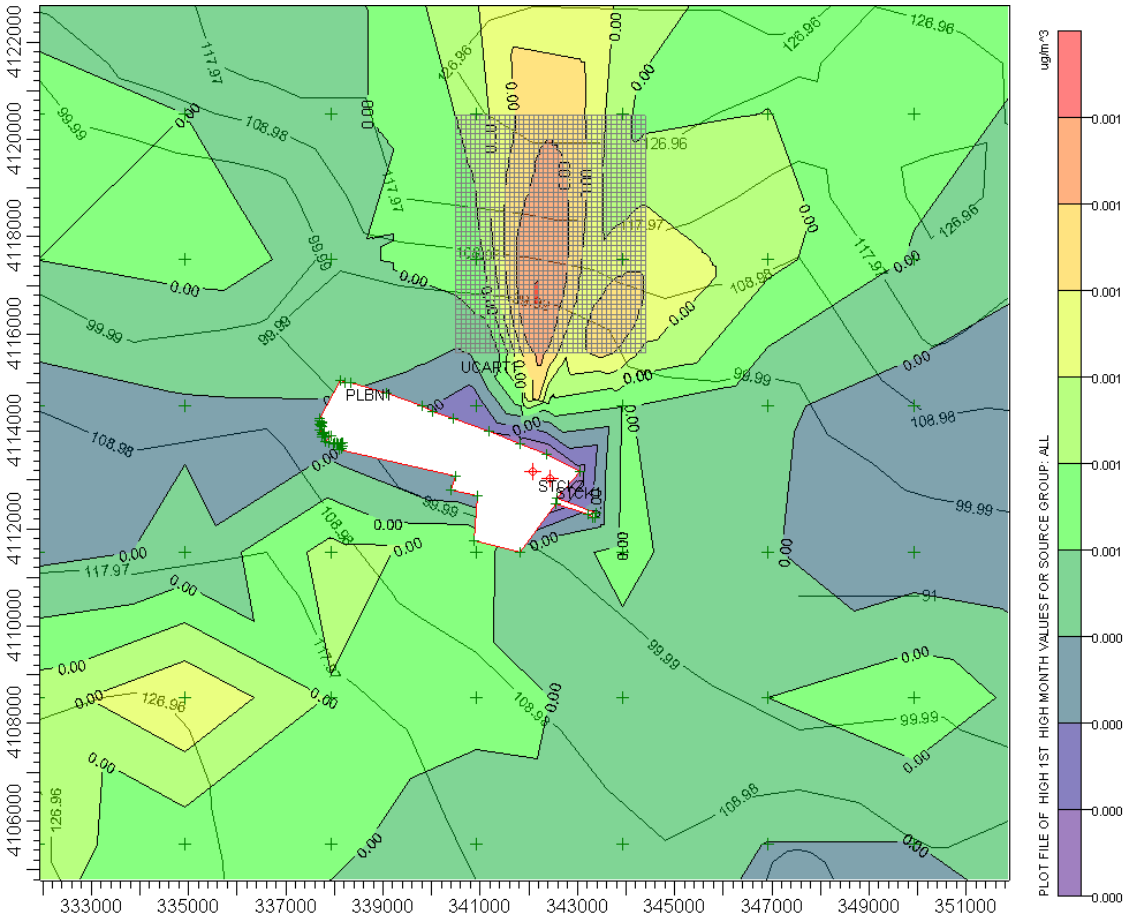


Figure 14. TVA-Site, High 1st High Monthly Average Concentration, Entire Domain

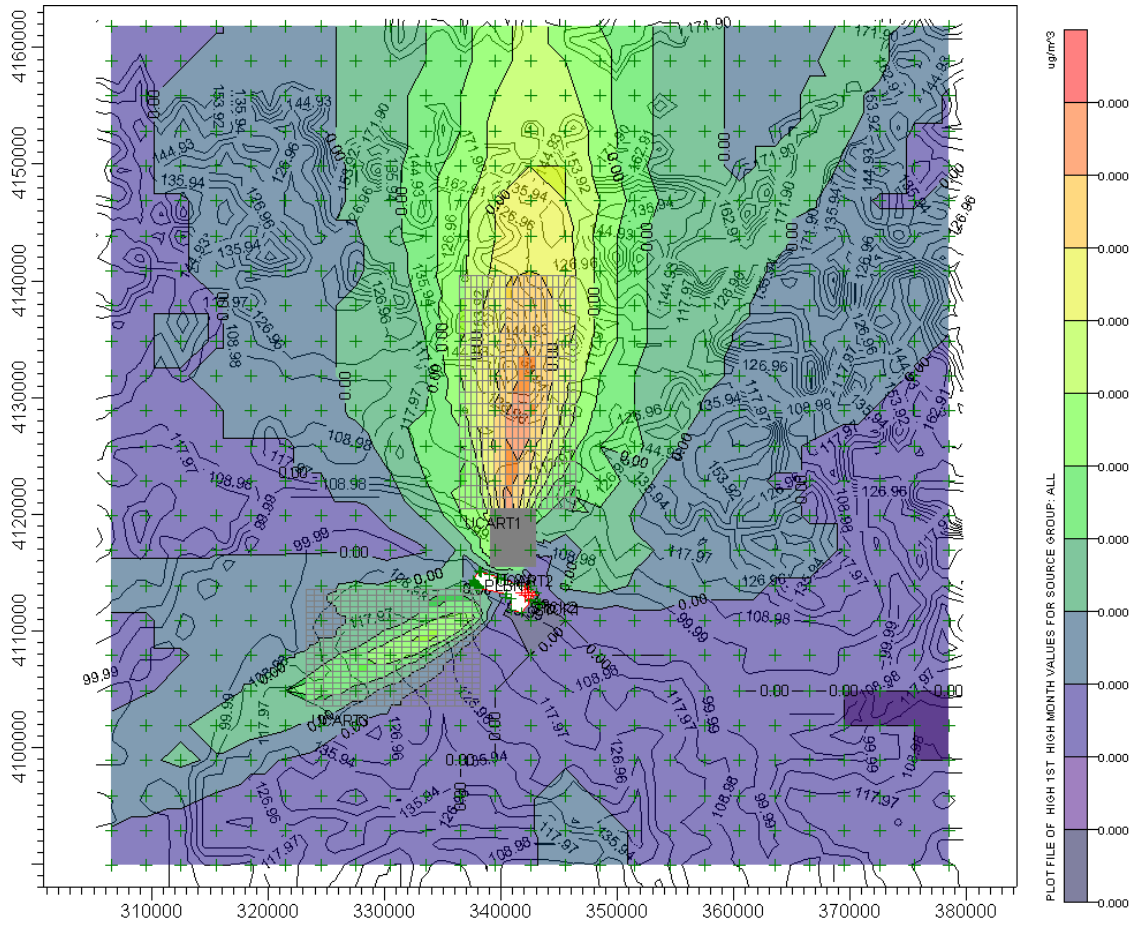
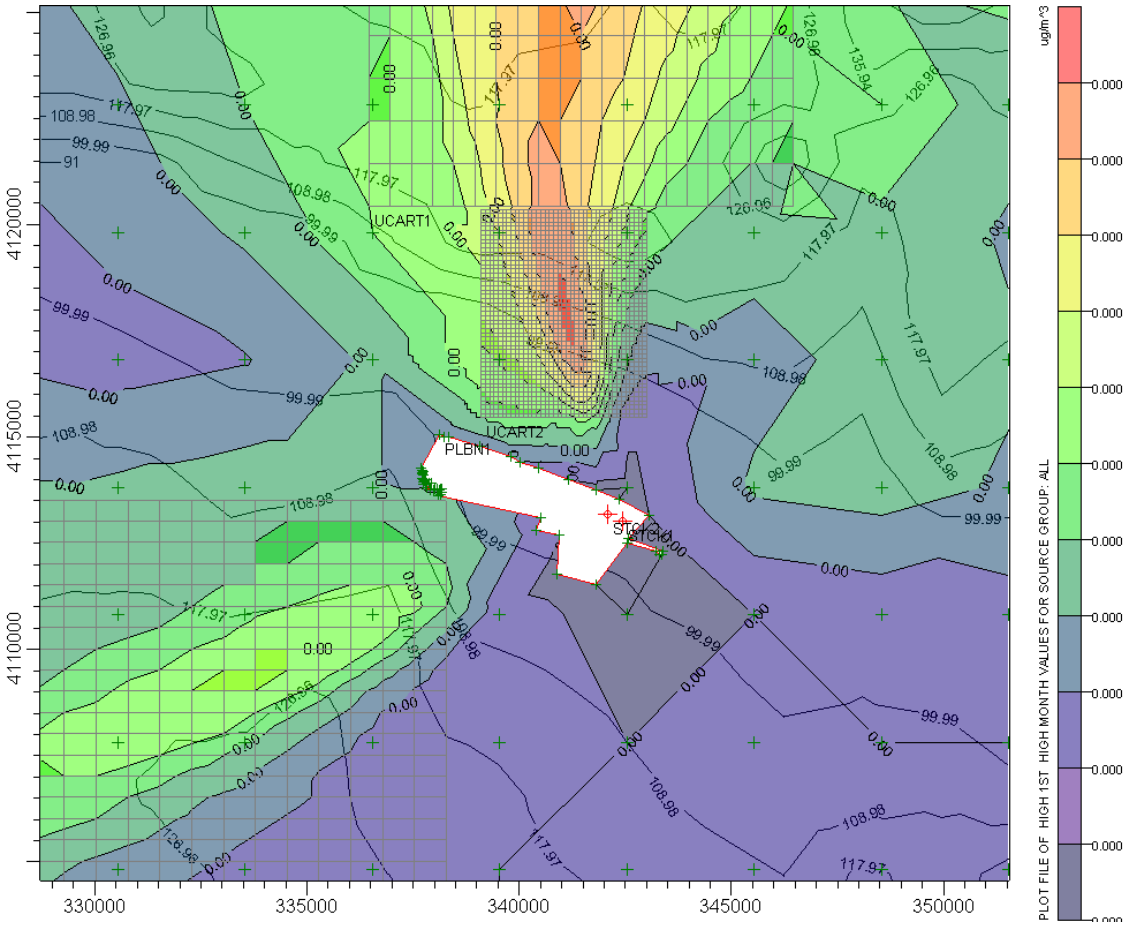


Figure 14.1 TVA-Site, High 1st High Monthly Average Concentration, Controlling Concentration



Ambient Air Monitoring Network Plan
for
Source Oriented Lead (Pb)
Request for Waiver

CBSA
Louisville-Jefferson County
KY-IN MSA

Louisville Metro Air Pollution Control District
850 Barret Avenue
Louisville, KY 40204

Prepared by:
Larry Garrison
Environmental Supervisor
Air Quality Unit
May 28, 2009

Introduction:

On November 12, 2008 the United States Environmental Protection Agency (EPA) strengthened the National Ambient Air Quality Standard (NAAQS) for lead to increase protection of public health and the environment. Since 1978 the ambient air lead standards have been set at 1.5μg/m^3 and were based on a quarterly average. The new revised standards are set at 0.15μg/m^3 for the primary (health-based) and the secondary (welfare-based) standards and are calculated using a 3-month rolling average. In conjunction with the revision of the lead NAAQS, the EPA promulgated new monitoring requirements which can be found in 40 CFR Part 58, Appendix D. One of the requirements is to evaluate the adequacy of existing source oriented lead monitoring networks and/or to determine if additional lead monitoring networks are needed. The deadline for this review and the identification of source oriented lead monitoring sites is July 1, 2009 with monitoring to begin January 1, 2010. Based on this requirement and guidance issued by EPA the Louisville Metro Air Pollution Control District (LMAPCD) has evaluated historical data as well as current emissions inventories to determine the applicability and design of a source oriented lead monitoring network in Jefferson County, Kentucky.

Wavier Provisions:

40 CFR Part 58 Appendix D, Section 4.5(ii) contains waiver provisions for source oriented lead monitoring. Monitoring may be waived for sources if the state or local agency can demonstrate that the lead source will not contribute to a maximum lead concentration in ambient air in excess of 50% of the NAAQS (0.075μg/m^3). This demonstration may be based on historical monitoring data, modeling, or other means.

Evaluation of Historical Data:

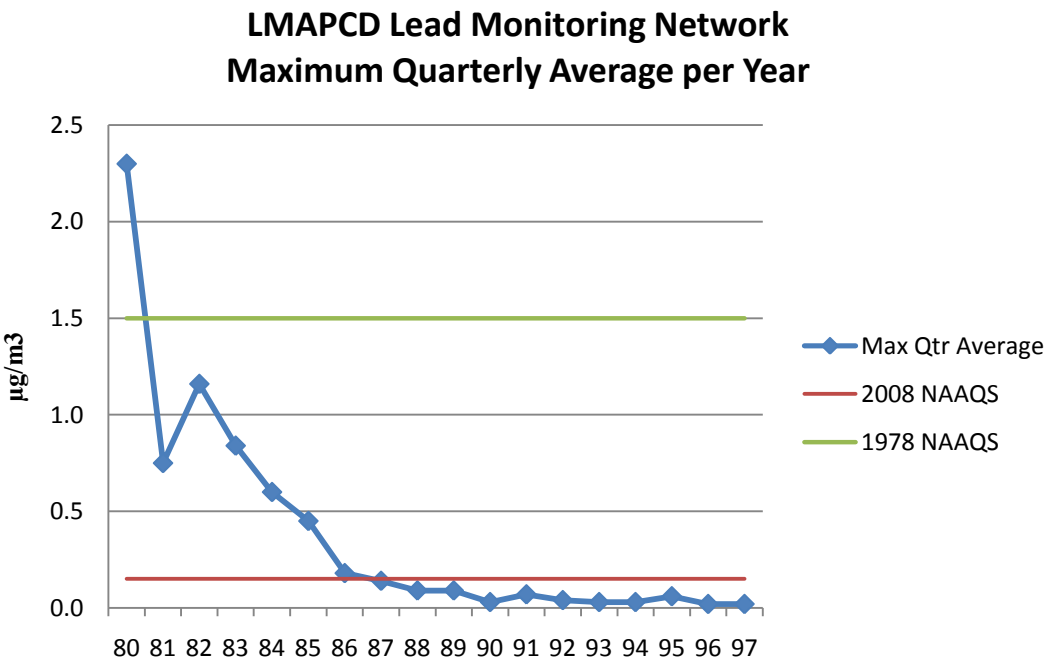
LMAPCD operated a lead monitoring network designed to monitor mobile and facility emissions during the period of (1980-1997). The monitoring was conducted according to the methods listed in 40 CFR Part 50 Appendix G *Reference Method for the Determination of Lead in Suspended Particulate Matter Collected from Ambient Air.* Removal of lead from automotive gasoline and the installation of particulate control systems at facilities resulted in a sharp decline in lead emissions and as measured levels declined the monitoring network was reduced to just two sites in 1988. Based on recommendations made by EPA and the fact that measured levels were significantly below the NAAQS, LMAPCD discontinued lead monitoring in 1997 to free up resources for the upcoming $PM_{2.5}$ monitoring program. Table 1 and Chart 1 provide a summary of the data collected by that network. Although the averaging method used for the old standard is different the data indicate that at the end of the lead monitoring program, the maximum quarterly averages were approximately 13% of the new NAAQS.

Table 1
Lead: Monitoring History
Values are maximum quarterly averages ($\mu g/m^3$)

Site	Location	Sampling Year																	
		80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97
6028	Shivley	1.2	0.47	0.40	0.30	0.17	0.11	0.08	-	-	-	-	-	-	-	-	-	-	-
6035	Sanders	0.6	0.26	-	-	-	0.09	-	-	-	-	-	-	-	-	-	-	-	-
6036	Lake Dreamland	0.9	0.18	0.40	0.16	0.16	0.10	0.08	-	-	-	-	-	-	-	-	-	-	-
6038	Okolona	2.3	0.75	1.16	0.69	0.49	0.35	0.16	0.09	-	-	-	-	-	-	-	-	-	-
6038	Okolona(c)	-	-	-	-	-	0.38	0.16	0.10	-	-	-	-	-	-	-	-	-	-
6050	Floyd & Jefferson	2.3	0.49	0.89	0.55	0.41	0.38	0.16	0.14	-	-	-	-	-	-	-	-	-	-
6052	Deer Park	1.6	0.41	0.60	0.33	0.23	0.24	0.09	-	-	-	-	-	-	-	-	-	-	-
6054	Bates	0.4	0.13	0.31	0.13	0.10	0.09	0.05	0.02	-	-	-	-	-	-	-	-	-	-
6055	WLKY	1.3	0.37	0.62	0.32	0.19	0.19	0.09	-	-	-	-	-	-	-	-	-	-	-
6058	Buechel	1.3	0.39	0.44	0.41	0.24	0.17	0.08	0.06	-	-	-	-	-	-	-	-	-	-
6059	Portland	1.6	0.43	0.45	0.42	0.28	0.21	0.12	0.08	-	-	-	-	-	-	-	-	-	-
6061	Valley Village	1.5	0.42	0.79	0.39	0.26	0.21	0.10	0.07	-	-	-	-	-	-	-	-	-	-
6063	Saint Matthews	1.6	0.48	0.62	0.44	0.26	0.20	0.10	0.07	-	-	-	-	-	-	-	-	-	-
6099	Boy Scouts	-	-	0.94	0.84	0.60	0.45	-	-	-	-	-	-	-	-	-	-	-	-
6101	Southwick	-	-	-	0.38	0.27	0.19	0.09	0.07	-	-	-	-	-	-	-	-	-	-
6101	Southwick (c)	-	-	-	-	-	0.19	0.09	0.07	-	-	-	-	-	-	-	-	-	-
6102	Wyandotte	-	-	-	0.49	0.47	0.34	0.18	0.09	0.09	0.09	0.01	0.04	0.02	0.03	0.02	0.06	0.01	0.01
6106	Riverport	-	-	-	-	-	-	0.06	0.06	-	-	-	-	-	-	-	-	-	-
6107	St. Stephens	-	-	-	-	-	-	-	-	-	0.00	0.01	0.06	0.04	0.03	0.03	0.05	0.02	0.02
6107	St. Stephens (c)	-	-	-	-	-	-	-	-	-	0.00	0.03	0.07	0.03	0.03	0.02	0.05	0.02	0.02

(c)- co-located sampler

Chart 1:



West Jefferson Air Toxics Study

From April 2000-April 2001, LMAPCD conducted an air toxics study for West Jefferson County. A component of that study was the collection of metals which included lead. Samples were collected every 12 days using the Hi-Volume method prescribed in 40 CFR Part 50 Appendix G. The samples were analyzed at EPA's Science and Ecosystem Support Division (SESD) laboratory in Athens, Georgia using ICP/MS. According to SESD the typical detection limit using this method was 0.0006024µg/m^3. Table 2 contains a summary of the 3-month rolling averages from that data. The numbers in **Bold** are the maximum 3-month rolling average values for each site. The maximum 24-hour value recorded was 0.035µg/m^3.

Table 2: Lead Results from West Jefferson Air Toxics Study
(Results are 3 month rolling averages in µg/m^3)

Sampling Period	Ralph Avenue 21-111-0054	Lake Dreamland 21-111-0055	St. Stephens Church 21-111-0056	Shelby Campus 21-111-0057	Firearms Training 21-111-1014
04-06/2000	.0083	.0093	.0133	-	.0012
05-07/2000	.0090	.0081	.0113	.0066	.0103
06-08/2000	.0106	.0079	.0124	.0048	.0091
07-09/2000	.0084	.0070	**.0189**	.0039	.0088
08-10/2000	.0121	.0093	.0129	.0083	.0149
09-11/2000	.0167	.0142	.0143	.0134	**.0199**
10-12/2000	**.0174**	**.0155**	.0133	**.0138**	.0194
11-01/2000-2001	.0150	.0136	.0125	.0124	.0163
12-02/2000-2001	.0103	.0106	.0121	.0089	.0138
01-03/2001	.0105	.0103	.0123	.0072	.0129
02-04/2001	.0083	.0115	.0149	.0048	.0078

Identification of Lead Sources:
40 CFR Part 58, Appendix D, Section 4.5(a) requires monitoring at sources that emit 1.0 ton per year (tpy) or more of lead to the air. Monitoring agencies must use the most recent National Emissions Inventory (NEI) data or other scientifically justifiable methods and data to determine if a facility emits more than 1.0 tpy. Based on a review of the latest National Emissions Inventory data, 2006-2007 local inventory data and a review of the 2006-2007 Toxics Release Inventory (TRI) data, LMAPCD has identified the Louisville Gas & Electric Mill Creek facility as the only source in Jefferson County that emits more than 1.0 tpy of lead to the air. The 2005 NEI data for LG&E Mill Creek indicates their emissions were 0.97 tpy.

Table 3: Lead Sources in Jefferson County (tpy)

Facility Name	2006 LMAPCD inventory	2007 LMAPCD inventory
LG&E Mill Creek	0.94	**1.01**
LG&E Cane Run	0.35	0.35
Oxy Vinyls LP	0.11	0.13
Kosmos Cement Co.	0.11	0.108
Industrial Container Services	0.136	0.019
Bluegrass Cooperage	0.000	0.00498
Poly One	0.028	0.004

Modeling Parameters:

Using guidance provided in EPA's "Technical Note-Dispersion Modeling for Lead (Pb) Sources" LMAPCD conducted dispersion modeling for the Mill Creek facility using the AERMOD model for near-field dispersion. The modeling performed relied on five years of meteorological data taken from the most representative surface and upper air meteorological stations. For surface, meteorological data for years 1989-1993 from the Louisville International Airport were used. The airport is approximately 18 km north east of the facility and has similar topography. For upper air, meteorological data for 1989-1993 were used from the Dayton Wright Patterson Air Force Base. The 1989-1993 data sets were used because they were the most complete.

Source Pathway –Source Inputs

The LG&E Mill Creek facility is a coal fired electric utility that uses 4 commercial boilers (units) for generation of electricity via steam turbines and generators. The combined generating capacity of the 4 units is approximately 1,610 MW. Most of the lead emissions are attributed to the combustion of coal and the annual emission rates were calculated using updated throughputs and AP-42 emission factors for controlled coal combustion sources. Each unit utilizes emissions control equipment consisting of an electrostatic precipitator, a sulfur dioxide removal system and a dry centrifugal dust collector for the coal bunker. The final emission points are four individual stacks that are approximately 182 meters high. Table 4 contains the source inputs for each stack.

Table 4: Source Inputs

Source Type	ID	X coordinate (m)	Y coordinate (m)	Base elevation	Release Height (m)	Emission rate (g/s)	Gas Exit Temp (K)	Gas Exit velocity (m/s)	Stack Inside Diameter (m)
Point	STCK1	595606.79	4212148.98	0.00	182.88	0.14460	325.37	19.46	4.72
Point	STCK2	595606.10	4212191.80	0.00	182.88	0.12980	327.04	21.08	4.72
Point	STCK3	595600.37	4212287.52	0.00	182.88	0.18580	327.04	19.98	5.52
Point	STCK4	595602.65	4212307.55	0.00	182.88	0.24000	324.82	22.45	5.94

Other inputs used in the model were:

- Averaging time was set to one month to facilitate the calculation of a three month rolling average and to use the lead post processor provided by EPA.
- The toxics non default option was chosen to access the total deposition output.
- For source pathway "particulate" was chosen for gas and particle deposition.
- Based on the assumption that only a small fraction (<10%) of the mass is greater than 10 microns, Method 2 was selected for handling particle deposition by total particulate mass.
- Particle inputs for Method 2 consisted of the fine particle fraction equaling 0.75 and the mass mean particle diameter equaling 0.5 microns.
- No volume sources were specified.
- No area sources were specified.
- No open pit sources were specified.
- No circular area sources were specified.

- No polygon area sources were specified.
- No flare sources were specified.
- No line sources were specified.
- Flat terrain was assumed for the entire modeling domain.

Results and Discussion:

Although the historical monitoring data collected in 1980-1997 used a different averaging method, the evaluation of that data indicates that the measured values were significantly below 0.15μg/m^3 at the time monitoring was terminated in 1997. The evaluation of the lead results from the (2000-2001) West Jefferson County Air Toxics Study also indicates measured values significantly below the new standard. These results were compiled using the 3-month rolling average that applies to the new standard.

The modeling results for Mill Creek indicate that the maximum 1-month average was 0.01914μg/m^3. Using the post processor provided by EPA the overall maximum 3-month concentration was 0.01μg/m^3. This is substantially below the 50% NAAQS threshold of 0.075μg/m^3 and is consistent with the historical measured values indicated in Tables 1 and 2. The plots of the high month values for the source as well as the output files for the maximum 3-month average concentration are attached.

Conclusion:

Based on historical monitored data and the modeling results, LMAPCD has demonstrated that a source oriented lead monitoring network is not warranted and **requests a waiver** for monitoring at the LG&E Mill Creek facility. Should the waiver be granted, LMAPCD will renew the waiver request during each 5 year network assessment required by 40 CFR Part 58.10(d). LMAPCD will also review emissions inventory data during its annual network review to determine if significant changes in lead emissions occur.

APPENDIX D

Public Comment

NOTICE OF PUBLIC COMMENT PERIOD
KENTUCKY DIVISION FOR AIR QUALITY
AMBIENT AIR MONITORING NETWORK

In accordance with 40 C.F.R. 58.10(a)(1), the Kentucky Energy and Environment Cabinet will make the annual monitoring network plan available for public inspection for at least 30 days prior to submission to the U.S. EPA. The annual monitoring network plan details the operation and location of ambient air monitors operated by the Kentucky Division for Air Quality, Louisville Metro Air Pollution Control District, and the National Park Service.

The public comment period relating to the annual monitoring network will begin May 29, 2009, and will conclude on June 28, 2009. Copies of the annual monitoring plan are available for public inspection at the locations listed below. Any individual requiring copies may submit a request to the Division for Air Quality in writing, by telephone, by FAX, or by electronic mail. Requests for copies should be directed to the contact person. In addition, an electronic version of the proposed annual monitoring network plan and relevant attachments can be downloaded from the Division for Air Quality's website at:

http://www.air.ky.gov/homepage_repository/Public+Notices.htm

Again, to be considered part of the record, comments must be received by June 28, 2009. Comments should be sent directly to the contact person.

CONTACT PERSON: Andrea P. Keatley, Environmental Scientist II, Division for Air Quality, 200 Fair Oaks Lane, 1st Floor, Frankfort, Kentucky 40601. Phone: (502) 564-3999; FAX: (502) 564-4666; email: Andrea.Keatley@ky.gov

The Energy and Environment Cabinet does not discriminate on the basis of race, color, national origin, sex, age, religion, or disability and provides, upon request, reasonable accommodation including auxiliary aids and services necessary to afford an individual with a disability an equal opportunity to participate in all services, programs, and activities.

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Ashland Regional Office
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Ashland, KY 41102-8942

Bowling Green Regional Office
1508 Westen Avenue
Bowling Green, KY 42104

Frankfort Regional Office
663 Teton Trail, Suite B
Frankfort, KY 40601-1758

Hazard Regional Office
233 Birch Street, Suite 2
Hazard, KY 41701-2179

London Regional Office
875 S Main Street
London, KY 40741

Paducah Regional Office
130 Eagle Nest Drive
Paducah, KY 42003-0823

Florence Regional Office
8020 Veterans Mem Dr, Suite 110
Florence, KY 41042

Owensboro Regional Office
3032 Alvey Park Dr, Suite 700
Owensboro, KY 42303-2191

SCOPE

Shelby County Organized for Preservation and Enhancement, Inc.

4404 Cropper Road, Shelbyville, KY 40065

Reggie Van Stockum
President
502-633-3813

Ted Thomas
Vice President & Secretary
502-633-9529

Flora Sherrod
Treasurer
502-633-9505

June 18, 2009

Via U.S. Mail and
Email: Andrea.keatley@ky.gov

Andrea P. Keatley
Kentucky Energy and Environment Cabinet
Division for Air Quality
200 Fair Oaks Lane
Frankfort, KY 40601

RE: Public Comment on the Kentucky Ambient Air Monitoring Network

Dear Ms. Keatley:

Shelby County Organized for Preservation and Enhancement, Inc. (SCOPE) is a not-for-profit citizens' group in Shelby County, Kentucky. SCOPE offers the following comment to the Kentucky Division of Air Quality's (DAQ) Public Notice relating to its Ambient Air Monitoring Network.

SCOPE has examined DAQ's proposed Ambient Air Quality Monitoring Plan. SCOPE notes that there are multiple monitoring stations in Jefferson County, Oldham County and Bullitt County, Kentucky. There appear, however, to be no such stations existing in (or proposed for) Shelby County, Kentucky.

Shelby County, Kentucky is immediately adjacent to the east of Jefferson County, Kentucky, has a significant industrial base, and is bisected by Interstate I-65.

SCOPE wishes to preserve and enhance the quality of the air in Shelby County. SCOPE believes that air-monitoring stations similar to those found in Jefferson, Bullitt and Oldham Counties should be established in Shelby County for that purpose.

Thank you for your consideration of these comments.

Sincerely,

Ronald R. Van Stockum, Jr.
President, SCOPE

cc: SCOPE Board of Directors
John Lyons, DAQ

Paducah Area
CHAMBER OF COMMERCE

June 17, 2009

Andrea P. Keatley
Environmental Scientist II
Kentucky Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601

RE: Public Comment
Kentucky Division for Air Quality
Ambient Air Monitoring Network

Dear Ms. Keatley:

On behalf of the Board of Directors of the Paducah Area Chamber of Commerce, thank you for making the Division's Air Quality Monitoring Plan available for public review and comment.
The Paducah Commerce feels that monitoring the current status of air quality and reporting an area's progress on meeting the National Ambient Air Quality Standards is important to our community and to the Commonwealth.

However, we are not sure if the Division is aware that the Paducah Middle School located at 342 Lone Oak Road in Paducah is in the process of deciding on a site for a new school building. Currently, AQS Site ID 21-145-1004 Air Quality Monitor is located on the roof of the Paducah Middle School. If the Paducah Middle School decides to move, we feel the viability of an unoccupied building as an air monitoring site becomes questionable.

Although the move is not scheduled to occur prior 2012, we would suggest that the Division start the process to select an alternate site for this monitor.

The contact for the Paducah City School System is Mr. Troy Brock at 270-444-5600.

If the Chamber can be of assistance in relocating this monitoring location, please contact Chamber President Elaine Spalding at 270- 443-1746 x 205 or e-mail espalding@paducahchamber.org

Sincerely,

Susan Guess

Susan Guess
Chair of the Board

PADUCAH Kentucky
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Kentucky UNBRIDLED SPIRIT

Andrea P. Keatley
Environmental Scientist II
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, KY 40601

June 27, 2009

Dear Ms. Keatley,

Following are comments from the Kentucky Environmental Foundation et al on the 2009 Air Quality Ambient Air Monitoring Network. Our organizations are concerned with the impacts of toxic pollutants in our air and strive to find solutions to improve our air quality and protect our health and the environment, and provide this comments to the Department of Air Quality with that goal in mind.

Particulate Matter Monitoring

Given the number of stationary sources of particulate matter (PM) in Kentucky, namely coal fired power plants, and the health risks associated with PM2.5 in particular, it seems that the number of PM2.5 monitoring stations is inadequate. Particulate matter is linked to asthma, chronic obstructive pulmonary disorder, heart disease and a wide range of other serious illnesses.[1] Given that, the monitoring network appears to be lacking in monitors that could accurately measure emissions from facilities such as the Spurlock power plant in Maysville and the Dale plant in Clark County. We request that DAQ revisit the emissions deposition around these facilities. DAQ could use CMAQ modeling to predict maximum downwind impact from power plants, as a means of determining the best placement of PM2.5 monitors.

In addition, there are proposed coal-fired power plants in Clark and Estill Counties, yet the nearest monitoring station in Richmond may not be adequate to establish an accurate

[1] Health Effects Institute. Research Report: Extended Analysis of the American Cancer Society Study of Particulate Air Pollution and Mortality. Number 140, May 2009.
Pope,C.A., III, Ezzati,M., Dockery,D.W., 2009. Fine-Particulate Air Pollution and Life Expectancy in the United States, N Engl J Med 360, pp. 376-386.
Dominici,F., Peng,R.D., Bell,M.L., Pham,L., McDermott,A., Zeger,S.L., Samet,J.M., 2006. Fine particulate air pollution and hospital admission for cardiovascular and respiratory diseases, JAMA 295, pp. 1127-1134.
Pope,C.A., III, Burnett,R.T., Thun,M.J., Calle,E.E., Krewski,D., Ito,K., Thurston,G.D., 2002. Lung cancer, cardiopulmonary mortality and long-term exposure to fine particulate air pollution. JAMA 287, pp. 1132-1141.
Villeneuve PJ, Chen L, Rowe BH, Coates F. Outdoor air pollution and emergency department visits for asthma among children and adults: a case-crossover study in northern Alberta, Canada. Environmental Health, Dec. 24, 2007.

reading of air emissions from those facilities, should they come to be. DAQ should consider adding monitoring stations for particulate matter in these areas.

DAQ should also consider the increase in air pollution from increased residential and industrial development. Some regions of Kentucky, including the central Kentucky region surrounding Lexington, are fast changing with increasing residential sprawl into rural areas, an increase in automobile traffic, construction-related air emissions and therefore an increase in the levels of particulate matter from these and other sources. DAQ should consult with EPA on urban growth air modeling strategies and the necessity of additional monitoring capabilities.

Mercury Monitoring

Mercury is a high-risk toxicant with myriad human health impacts, most notably linked to developmental disorders.[2] Despite the fact that coal fired power plants are a leading source of mercury, Kentucky does not appear to be adequately measuring the most toxic form of mercury – methylmercury – originating from power plants and other industrial facilities. Kentucky's waterways already carry fish consumption advisories due to high levels of toxic mercury. The air monitoring network plan could include fish tissue sampling in order to determine the impacts of air releases of mercury on wildlife and human health, and back trajectory modeling of contaminated fish could also identify the source of the mercury, so that the state can take a more precautionary approach to reducing mercury emissions.

Lead Monitoring

To begin with, DAQ's monitoring network plan modeling ignored emissions from start-up and shut-down of facilities, which can be at emissions rates at 100 – 400 times more than routine facility operations. The plan should therefore be modified to include that inevitability.

KY DAQ is requesting a waiver of the source specific monitoring requirement for lead for Superior Battery, AEP Big Sandy Plant, Newpage, TVA Shawnee Fossil Plant, North American Stainless and LG&E Mill Creek even though these sources have over 1 ton per year (TPY) of lead emissions. However, because this request is based on inadequate modeling, it is arbitrary. Thus, the waiver cannot be granted and KY DAQ must design

[2] Philip W. Davidson, PhD, Gary J. Myers, MD and Bernard Weiss, PhD. Philip W. Mercury Exposure and Child Development Outcomes. PEDIATRICS Vol. 113 No. 4 April 2004.
RL Jones, PhD, T Sinks, PhD, SE Schober, PhD, M Pickett, MPH. Blood Mercury Levels in Young Children and Childbearing-Aged Women --- United States, 1999—2002. National Center for Environmental Health; National Center for Health Statistics, CDC. November 2004.
Clarkson N. Current concepts: the toxicology of mercury---current exposures and clinical manifestations [Review]. N Engl J Med 2003.
National Academy of Sciences. Toxicologic effects of methylmercury. Washington, DC: National Research Council; 2000.

its monitoring plan to include source specific monitoring for lead for Superior Battery, AEP Big Sandy Plant, Newpage, TVA Shawnee Fossil Plant, North American Stainless and LG&E Mill Creek.

To begin with, there is no evidence presented that the meteorological data used for the modeling that forms the basis of the waiver request is site-specific. See Plan at C-4. For Mill Creek, the upper air station data is from Dayton, Ohio, which is over 100 miles away from Mill Creek. See Plan at C-18. Modeling that is based on meteorological data from an area other than area that was modeled is not valid.

Furthermore, for Superior Battery, TVA Shawnee and Newpage, the modeling was based on upper air station meteorological data for just 26 days rather than 5 years of meteorological data. See Plan at C-4. DAQ admits that this data was inadequate. See Plan at C-4. There is no rational basis to assume that the 26 days of upper air station meteorological data in any way presents a rational approximation of actual ambient lead level impacts from these three sources. This is even more so the case in a place like Kentucky that experiences significant seasonal variations in weather and the 26 days of data was from the winter.

In addition, DAQ admits that it relied on outdated meteorological data because "The cost for more recent data for this particular project would be in excess of $2200. Unfortunately, funding for those data is unavailable." Plan at C-4. Thus, not only is the failure to require source specific monitoring for these sources arbitrary because the waiver request is based on outdated data, DAQ should not be allowed to implement the Clean Air Act with regard to lead at all. 42 U.S.C. 7410(a)(2)(E)(i) requires that State Implementation Plans include a demonstration that the state will have adequate funding to implement the program. Here, DAQ admits that it does not have adequate funding. It cannot come up with a mere $2200. Thus, EPA, rather than DAQ, should implement the Clean Air Act with regard to lead in Kentucky.

Turning back specifically to the lead monitoring waiver request, the modeling that DAQ is relying upon is arbitrary because it relies on airport meteorological data which is invalid and is contrary to EPA's modeling guidance. See Plan at C-4, C-18. For air dispersion modeling purposes, airport data are among the least desirable.

Problems with location and the general quality of data are the primary concerns. EPA, in their Meteorological Monitoring Guidance for Regulatory Modeling Applications, summarizes these concerns about using airport data:

For practical purposes, because airport data were readily available, most regulatory modeling was initially performed using these data; however, one should beware that airport data, in general do not meet this guidance.[3] First Airports are comprised of concrete runways, parking lots, passenger terminals, and other structures associated with air travel activities. These surface and building characteristics in turn affect the boundary

[3] EPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 1-1.

layer meteorology present at the airport.[4] In addition, landings, takeoffs, and idling of airplanes affect the site-specific conditions at the airport such that the meteorological conditions are not representative of the area surrounding the 6 facilities requesting waivers, several of which are adjacent to a water bodies. Second, another major issue is the quality of the meteorological data collected at the Airports. It is important to remember that the airport data are not collected with the thought of air dispersion modeling in mind. For example, airport conditions are typically reported once per hour, based on a single observation (usually) taken in the last ten minutes of each hour. EPA recommends that sampling rates of 60 to 360 per hour, at a minimum, be used to calculate hourly-averaged meteorological data.[5] Air dispersion modeling requires hourly-averaged data, which represents the entire hour being modeled, not a snapshot taken in one moment during the hour.

In addition, data collected at Airports are not subject to the system accuracies required for meteorological data collected for air dispersion modeling. EPA recommends that meteorological monitoring for dispersion modeling use equipment that are sensitive enough to measure all conditions necessary for verifying compliance with the NAAQS and PSD increments. For example, low wind speeds (down to 1.0 meter per second) are usually associated with peak air quality impacts - this is because modeled impacts are inversely proportional to wind speed. Following EPA guidance, wind speed measuring devices (anemometers) should have a starting threshold of 0.5 meter per second or less.[6] Furthermore, wind speed measurements should be accurate to within plus or minus 0.2 meter per second, with a measurement resolution of 0.1 meter per second.[7]

Airport data, rather than being measured in 0.1 meter per second increments, is usually based on wind speed observations that are reported in whole knots. To further exemplify the problem of using the airport data, the lowest wind speed included in the airport meteorological data files is usually 1.56 meters per second (three knots).

In addition, all winds lower than three knots are reported as calms, and are thus excluded from the modeling analyses. The conditions most crucial for verifying compliance with the lead threshold for the waiver are being excluded from the analysis because of the choice to use the airport data. Sensitive and accurate measurements of wind speeds are necessary for measuring winds down to 0.5 meter per second (about one knot), which can then be used as 1.0 meter per second in the air dispersion modeling analyses. There would be no need to label such low wind speed hours as calm, which will greatly increase the number of hours included in the modeling analyses. Again, it is these low wind speed hours which must be included in the modeling data set to verify compliance with the lead threshold. Because DAQ failed to do this, a waiver cannot be granted and source specific monitoring of these 6 sources must be conducted.

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[4] Oke T.R., Boundary Layer Climates, Halsted Press, 1978, pp. 240-241.

[5] EPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 4-2.

[6] Id., p. 5-2.

[7] Id., p. 5-1.

Thank you for your attention to these comments. If you have any questions please contact Elizabeth Crowe, Kentucky Environmental Foundation, (859) 986-0868. Otherwise we look forward to your response.

Sincerely,

Elizabeth Crowe, Executive Director
Kentucky Environmental Foundation
PO Box 467 Berea, KY 40403

James Gignac, Midwest Director
Sierra Club National Coal Campaign
70 East Lake Street, Suite 1500
Chicago, IL 60601

Robert Ukeiley
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Berea, KY 40403

KENTUCKY DIVISION FOR AIR QUALITY
AMBIENT AIR MONITORING NETWORK
Comments Received 6/29/2009

Energy and Environment cabinet
Department for Environmental Protection
Division for Air Quality

(1) A public comment period on the KENTUCKY DIVISION FOR AIR QUALITY AMBIENT AIR MONITORING NETWORK 2009 was held from May 29, 2009 through June 28, 2009.

(2) The following individuals submitted written comments during the public comment period:

Name and Title	**Organization**
Ronald R. Van Stockum, Jr., President	Shelby County Organized for Preservation and Enhancement, Inc.
Susan Guess, Chair of Board	Paducah Area Chamber of Commerce
Elizabeth Crowe, Executive Director	Kentucky Environmental Foundation
James Gignac, Midwest Director	Sierra Club National Coal Campaign
Robert Ukeiley	Law Office of Robert Ukeiley
John Belanger, MD	
Joan Moore, MS, FNP	

Summary of Comments

(1) Subject: Shelby County Air Monitoring

(a) Comment: The Shelby County Organized for Preservation and Enhancement, Inc. (SCOPE) commented "SCOPE wishes to preserve and enhance the quality of the air in Shelby County. SCOPE believes that air-monitoring stations similar to those found in Jefferson, Bullitt and Oldham Counties should be established in Shelby County for that purpose."
Ronald R. Van Stockum, Jr., Shelby County Organized for Preservation and Enhancement, Inc. (SCOPE)

(b) Response: The division acknowledges this comment and shall take it into consideration during the 2010 five-year network assessment. Currently, the division is meeting the monitoring requirements for the ambient air monitoring network as required in 40 CFR Part 58 Appendices A, C, D, E and G.

(2) Subject: Paducah Middle School Monitor Site 21-145-1004

(a) Comment: The Paducah Area Chamber of Commerce commented "…we are not sure if the Division is aware that the Paducah Middle School located at 342 Lone Oak Road in Paducah is in the process of deciding on a site for a new school building. Currently, AQS Site 21-145-1004 Air Quality Monitor is located on the roof of the Paducah Middle School. If the Paducah Middle School decides to move, we feel the viability of an unoccupied building as an air monitoring site becomes questionable. **Although the move is not scheduled to occur prior to 2012, we would suggest that the Division start the process to select an alternate site for this monitor**. "
Susan Guess, Paducah Area Chamber of Commerce

(b) Response: The division acknowledges this comment.

(3) Subject: Particulate Matter Monitoring

(a) Comment: The Kentucky Environmental Foundation et al commented "Given that, the monitoring network appears to be lacking in monitors that could accurately measure emissions from facilities such as the Spurlock power plant in Maysville and the Dale plant in Clark County. We request that DAQ revisit the emissions deposition around these facilities. DAQ could use CMAQ modeling to predict maximum downwind impact from power plants, as a means of determining the best placement of PM2.5 monitors."
Elizabeth Crowe, James Gignac, Robert Ukeiley, John Belanger, and Joan Moore, Kentucky Environmental Foundation et al.

(b) Response: The division acknowledges this comment. The division shall take into consideration the areas identified in the above mentioned comment for the 2010 five-year network assessment. However, the division is not lacking in monitors but exceeds the monitoring requirements for the PM2.5 network as required in 40 CFR Part 58 Appendices A, C, D, E and G.

(c) Comment: The Kentucky Environmental Foundation et al commented "In addition, there are proposed coal-fired power plants in Clark and Estill Counties, yet the nearest monitoring station in Richmond may not be adequate to establish an accurate reading of air emissions from those facilities, should they come to be. DAQ should consider adding monitoring stations for particulate matter in these areas."
Elizabeth Crowe, James Gignac, Robert Ukeiley, John Belanger, and Joan Moore, Kentucky Environmental Foundation et al.

(d) Response: The division acknowledges this comment. The division shall take into consideration the areas identified in the above mentioned comment for the 2010 five-year network assessment.

(e) Comment: The Kentucky Environmental Foundation et al commented "DAQ should also consider the increase in air pollution from increased residential and industrial development. Some regions of Kentucky, including the central Kentucky region surrounding Lexington, are fast changing with increasing residential sprawl into rural areas, an increase in automobile traffic, construction-related air emissions and therefore an increase in the levels of particulate matter from these and other sources. DAQ should consult with EPA on urban growth air modeling strategies and the necessity of additional monitoring capabilities."
Elizabeth Crowe, James Gignac, Robert Ukeiley, John Belanger, and Joan Moore, Kentucky Environmental Foundation et al.

(f) Response: The division acknowledges this comment. The division shall take into consideration the areas identified in the above mentioned comments for the 2010 five-year network assessment. However, the division is not lacking in monitors but exceeds the monitoring requirements for the PM2.5 network as required in 40 CFR Part 58 Appendices A, C, D, E and G.

(4) Subject: Mercury Monitoring

(a) Comment: The Kentucky Environmental Foundation et al commented "Despite the fact that coal fired power plants are a leading source of mercury, Kentucky does not appear to be adequately measuring the most toxic form of mercury – methylmercury – originating from power plants and other industrial facilities. Kentucky's waterways already carry fish consumption advisories due to high levels of toxic mercury. The air monitoring network plan could include fish tissue sampling in order to determine the impacts of air releases of mercury on wildlife and human health, and back trajectory modeling of contaminated fish could also identify the source of the mercury, so that the state can take a more precautionary approach to reducing mercury emissions."
Elizabeth Crowe, James Gignac, Robert Ukeiley, John Belanger, and Joan Moore, Kentucky Environmental Foundation et al.

(b) Response: The division acknowledges this comment. Fish tissue samples are collected by the Division of Water for the Department for Environmental Protection. The Division for Air Quality is also housed in the Department for Environmental Protection.

In January of 2007, an Affiliation Agreement was signed between the University of Louisville (UofL) and the Cabinet that houses the Department for Environmental Protection. The signed agreement allowed a student from the UofL School of Information and Public Health to begin the process of linking fish consumption advisories and all environmental data relating to mercury. The project cataloged all mercury data collected in Kentucky. The signed Affiliation Agreement allows current and future UofL students to continue the fish consumption advisory project.

(5) Subject: Lead Monitoring

(a) Comment: The Kentucky Environmental Foundation et al commented "…DAQ's monitoring network plan modeling ignored emissions from start-up and shut-down of facilities, which can be at emissions rates at 100 – 400 times more than routine facility operations. The plan should therefore be modified to include that inevitability. "
Elizabeth Crowe, James Gignac, Robert Ukeiley, John Belanger, and Joan Moore, Kentucky Environmental Foundation et al.

(b) Response: The division acknowledges this comment and does not concur that the plan should be modified. The division followed 40 CFR Part 51 Appendix W and guidance "AERMOD Implementation Guide" revised March 19, 2009, provided by the U.S. Environmental Protection Agency (EPA). EPA also provided comments on the proposed lead waiver document. The division worked with EPA to provide the best possible modeled data available of the lead waiver request.

(c) Comment: The Kentucky Environmental Foundation et al commented "…because this request is based on inadequate modeling, it is arbitrary. Thus, the waiver cannot be granted and KY DAQ must design its monitoring plan to include source specific monitoring for lead for Superior Battery, AEP Big Sandy Plant, Newpage, TVA Shawnee Fossil Plant, North American Stainless and LG&E Mill Creek."
Elizabeth Crowe, James Gignac, Robert Ukeiley, John Belanger, and Joan Moore, Kentucky Environmental Foundation et al.

(d) Response: The division does not concur. The division followed 40 CFR Part 51 Appendix W and guidance "AERMOD Implementation Guide" revised March 19, 2009, provided by EPA. EPA also provided comments on the proposed lead waiver document. The division worked with EPA to provide the best possible modeled data available of the lead waiver request.

(e) Comment: The Kentucky Environmental Foundation et al commented "… there is no evidence presented that the meteorological data used for the modeling that forms the basis of the waiver request is site-specific… Modeling that is based on meteorological data from an area other than area that was modeled is not valid…Furthermore, for Superior Battery, TVA Shawnee and Newpage, the modeling was based on upper air station meteorological data for just 26 days rather than 5 years of meteorological data…There is no rational basis to assume that the 26 days of upper air station meteorological data in any way presents a rational approximation of actual ambient lead level impacts from these three sources…DAQ admits that it relied on outdated meteorological data because "The cost for more recent data for this particular project would be in excess of $2200. Unfortunately, funding for those data is unavailable."… Thus, not only is the failure to require source specific monitoring for these sources arbitrary because the waiver request is based on outdated data, DAQ should not be allowed to implement the Clean Air Act with regard to lead at all…the modeling that DAQ is relying upon is arbitrary because it relies on airport meteorological data which is invalid and is contrary to EPA's modeling guidance…For air dispersion modeling purposes, airport data are among the least desirable."

Elizabeth Crowe, James Gignac, Robert Ukeiley, John Belanger, and Joan Moore, Kentucky Environmental Foundation et al.

(f) Response: The division concurs in part. The meteorological data used in the model was not current. However, the division has obtained more current meteorological data and has re-run the model for the lead sources. The new model demonstrates that all of the previous sources, requesting a waiver for lead monitoring, still do not contribute to the lead ambient concentrations by more than ½ the lead NAAQS with the exception of the Superior Battery source located in Russell Springs, KY. The division will be locating a monitoring site near the Superior Battery source location.

The division does not concur that "Modeling that is based on meteorological data from an area other than area that was modeled is not valid…" or that "the modeling that DAQ is relying upon is arbitrary because it relies on airport meteorological data which is invalid and is contrary to EPA's modeling guidance…" The division has followed modeling guidance provided by 40 CFR Part 51 Appendix W, "AERMOD Implementation Guide" revised March 19, 2009, and through personal correspondence with EPA. The guidance provides for meteorological data to be used from multiple sources including airports and not limited to site-specific data.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

User ID: NOQ

SITE DESCRIPTION REPORT

Report Request ID: 791571 Report Code: AMP380 Sep. 20, 2010

GEOGRAPHIC SELECTIONS

Tribal State	County	Site	Parameter	POC	City	AQCR	UAR	CBSA	CSA	EPA Region	Method	Duration	Begin Date	End Date
21	117													
21	037													
39	017													
39	025													
39	027													
39	061													
39	165													

SELECTED OPTIONS

Option Type	Option Value
MERGE PDF FILES	YES

SORT ORDER

Order	Column
1	STATE_CODE
2	COUNTY_CODE
3	SITE_ID
4	EPA_REGION

GLOBAL DATES

Start Date	End Date
2007 01 01	2009 12 31

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 21-037-3002
Site Name: NKU
Local ID:
Street Address: 524A John Hill Road
City: Highland Heights
State: Kentucky
Zip Code: 41076
County: Campbell
Location Description: Monitoring Point
Location Setting: Rural
Coll. Method: GPS
Land Use: Agricultural
Date Established: 20070701
Date Terminated:
Last Updated: 20071005
Regional Eval. Date:
HQ Eval. Date:
AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN
CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN
Direct Met Site:
Met. Site ID:
Type Met Site:
Local Region:
Urban Area:
Not in an urban area
Dist to Met. Site(m):
EPA Region: Atlanta
Dist. to City(km):
City Population: 6554
Dir. to CBD:
Census Block: 2017
Block Group: 2
Census Tract: 05300
Class 1 Area:
Congressional District: 4
Time Zone: Eastern
Site Latitude: +39.021806
Site Longitude: - 84.474453
UTM Easting:
UTM Zone:
UTM Northing:
Scale:
Point/Line/Area: Point
Accuracy: 3
Datum: WGS84
Vert Accuracy:
Vertical Measure(m): 232.0
Vert Method: Topographic Map Interpolation
Vert Datum Mean Sea-Level

SITE COMMENTS

Site located on Northern Kentucky University's rural agricultural property.

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	14
SPECIAL PURPOSE	1

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Kentucky Division For Air Quality	20070701	

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 21-117-0007 Site Name: Local ID: KAIRS 3199
Street Address: 1401 DIXIE HWY, UNIVERSITY COLLEGE City: Covington
State: Kentucky Zip Code: County: Kenton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: GPS Code (Pseudo Range) Precise Position Land Use: Residential
Date Established: 19750101 Date Terminated: Last Updated:
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: W Met. Site ID:
Type Met Site: NWS Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): 12075 EPA Region: Atlanta
City Population: 43370 Dir. to CBD: SW Dist. to City(km): 3
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.072500 Site Longitude: - 84.525000 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4327530 UTM Easting: 714115
Accuracy: 0 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 225.0 Vert Accuracy: 0
Vert Datum Unknown Vert Method: Unknown

SITE COMMENTS

KY 3-199 CHASE LAW SCHOOL

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	12
SPECIAL PURPOSE	17
SUPLMNTL SPECIATI	65
OTHER	3

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Kentucky Division For Air Quality	19750101	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	MT ALLEN ROAD	200	1993		LOCAL ST OR HY	W

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 21-117-0007 Site Name: Local ID: KAIRS 3199

Street Address: 1401 DIXIE HWY, UNIVERSITY COLLEGE City: Covington

State: Kentucky Zip Code: County: Kenton

Location Description: Monitoring Point Location Setting: Suburban

Coll. Method: GPS Code (Pseudo Range) Precise Position Land Use: Residential

Date Established: 19750101 Date Terminated: Last Updated:

Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati

CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: W Met. Site ID:

Type Met Site: NWS Local Region:

Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): 12075 EPA Region: Atlanta

Dist. to City(km): 3

City Population: 43370 Dir. to CBD: SW Census Tract:

Census Block: Block Group: Class 1 Area:

Congressional District: Time Zone: Eastern

Site Latitude: +39.072500 Site Longitude: - 84.525000 UTM Easting: 714115

UTM Zone: 16 UTM Northing: 4327530 Scale: 24000 Point/Line/Area: Point

Accuracy: 0 Datum: NAD27 Vert Accuracy: 0

Vertical Measure(m): 225.0 Vert Method: Unknown

Vert Datum Unknown

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
2	DIXIE HIGHWAY	7000	1993		MAJ ST OR HY	N
3	I-71/75	95000	1993		EXPRESSWAY	E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-017-0003 | Site Name: VERITY H.S. | Local ID:
Street Address: BONITA & ST JOHN | City: Middletown
State: Ohio | Zip Code: 45044 | County: Butler
Location Description: Monitoring Point | Location Setting: Urban And Center City
Coll. Method: Interpolation | Land Use: Industrial
Date Established: 19730104 | Date Terminated: | Last Updated: 20091217
Regional Eval. Date: | HQ Eval. Date: | AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN | CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN | Direct Met Site: | Met. Site ID:
Type Met Site: | Local Region:
Urban Area: Cincinnati, OH-KY | Dist to Met. Site(m): | EPA Region: Chicago
City Population: 51605 | Dir. to CBD: NW | Dist. to City(km): 4.5
Census Block: | Block Group: | Census Tract:
Congressional District: | Class 1 Area:
Site Latitude: +39.493611 | Site Longitude: - 84.353889 | Time Zone: Eastern
UTM Zone: 16 | UTM Northing: 4374695 | UTM Easting: 727550
Accuracy: 12 | Datum: NAD27 | Scale: 24000 | Point/Line/Area: Point
Vertical Measure(m): 209.0 | Vert Accuracy: 1
Vert Datum NGVD29 | Vert Method: Topographic Map Interpolation

SITE COMMENTS

ON ROOF OF VERITY HIGH SCHOOL

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
QA COLLOCATED	1
SLAMS	6
OTHER	39
SPECIAL PURPOSE	26
NON-REGULATORY	8

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	19730104	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-017-0003
Site Name: VERITY H.S.
Local ID:
Street Address: BONITA & ST JOHN
City: Middletown
State: Ohio
Zip Code: 45044
County: Butler
Location Description: Monitoring Point
Location Setting: Urban And Center City
Coll. Method: Interpolation
Land Use: Industrial
Date Established: 19730104
Date Terminated:
Last Updated: 20091217
Regional Eval. Date:
HQ Eval. Date:
AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN
CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN
Direct Met Site:
Met. Site ID:
Type Met Site:
Local Region:
Urban Area: Cincinnati, OH-KY
Dist to Met. Site(m):
EPA Region: Chicago
City Population: 51605
Dir. to CBD: NW
Dist. to City(km): 4.5
Census Block:
Block Group:
Census Tract:
Congressional District:
Class 1 Area:
Time Zone: Eastern
Site Latitude: +39.493611
Site Longitude: - 84.353889
UTM Easting: 727550
UTM Zone: 16
UTM Northing: 4374695
Scale: 24000
Point/Line/Area: Point
Accuracy: 12
Datum: NAD27
Vert Accuracy: 1
Vertical Measure(m): 209.0
Vert Method: Topographic Map Interpolation
Vert Datum NGVD29

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	BREIEL BLVD.	10000	2001		MAJ ST OR HY	W
2	BONITA	4000	2001		LOCAL ST OR HY	N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-017-0004 Site Name: HAMILTON FIRE HOUSE Local ID:
Street Address: SCHULER AND BENDER City: Hamilton
State: Ohio Zip Code: 45011 County: Butler
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19820101 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Hamilton, OH Dist to Met. Site(m): EPA Region: Chicago
City Population: 60690 Dir. to CBD: Dist. to City(km):
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.383333 Site Longitude: - 84.544167 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4361990 UTM Easting: 711510
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 193.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	1

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19820101	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	BENDER	1000	1992		LOCAL ST OR HY	S
2	SCHULER	1000	1992		LOCAL ST OR HY	W

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-017-0015
Site Name: OHIO BELL
Local ID:
Street Address: 3901 LEFFERSON
City: Middletown
State: Ohio
Zip Code: 45044
County: Butler
Location Description: Monitoring Point
Location Setting: Suburban
Coll. Method: Interpolation
Land Use: Industrial
Date Established: 19910106
Date Terminated:
Last Updated: 20100421
Regional Eval. Date:
HQ Eval. Date:
AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN
CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN
Direct Met Site:
Met. Site ID:
Type Met Site:
Local Region:
Urban Area: Middletown, OH
Dist to Met. Site(m):
EPA Region: Chicago
City Population: 51605
Dir. to CBD: NW
Dist. to City(km): 3
Census Block:
Block Group:
Census Tract:
Congressional District:
Class 1 Area:
Time Zone: Eastern
Site Latitude: +39.489900
Site Longitude: - 84.364067
UTM Easting: 726689
UTM Zone: 16
UTM Northing: 4374276
Scale: 24000
Point/Line/Area: Point
Accuracy: 12
Datum: NAD27
Vert Accuracy: 1
Vertical Measure(m): 204.0
Vert Method: Topographic Map Interpolation
Vert Datum NGVD29

SITE COMMENTS

OHIO BELL FACILITY

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	11

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	19910106	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	LEFFERSON RD.	8000	2001		LOCAL ST OR HY	S

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-017-0016 Site Name: SACRED HEART SCHOOL Local ID:
Street Address: 400 NILLES RD. City: Fairfield
State: Ohio Zip Code: 45014 County: Butler
Location Description: Monitoring Point Location Setting: Urban And Center City
Coll. Method: Interpolation-Map Land Use: Residential
Date Established: 20001003 Date Terminated: Last Updated: 20090918
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Not in an urban area Dist to Met. Site(m): EPA Region: Chicago
City Population: 42097 Dir. to CBD: NW Dist. to City(km): 1
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.338333 Site Longitude: - 84.566389 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4356939 UTM Easting: 709741
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 187.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

SACRED HEART SCHOOL

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	3

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	20001003	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	NILLES ROAD	19520	2006		THRU ST OR HY	S
2	RIVER ROAD	10800	2000		LOCAL ST OR HY	E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-017-1004 Site Name: HOOK FIELD AIRPORT Local ID:
Street Address: HOOK FIELD AIRPORT City: Middletown
State: Ohio Zip Code: 45042 County: Butler
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19730101 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Middletown, OH Dist to Met. Site(m): EPA Region: Chicago
City Population: 51605 Dir. to CBD: SE Dist. to City(km):
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.530000 Site Longitude: - 84.392500 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4378635 UTM Easting: 724125
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 196.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

MONITORING TRAILOR AT HOOK FIELD AIRPORT

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	19730101	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	VERITY PARKWAY, S.R. 73	8011	2006		MAJ ST OR HY	N
2	ELMWOOD STREET	1500	2001		LOCAL ST OR HY	E
3	WILBRAHAM ROAD	2000	2001		LOCAL ST OR HY	S

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-025-0022 Site Name: CLERMONT COUNTY GOVERNMENT BLDG. Local ID:
Street Address: 2400 CLERMONT CENTER DR. City: Batavia
State: Ohio Zip Code: 45103 County: Clermont
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Residential
Date Established: 20010401 Date Terminated: Last Updated: 20100907
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 1617 Dir. to CBD: E Dist. to City(km): 31
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.082319 Site Longitude: - 84.144193 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4329605 UTM Easting: 747030
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 262.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	5

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	20010401	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	STATE ROUTE 32	30708	2005		EXPRESSWAY	S

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-027-1002 Site Name: MONITOR AT LAUREL CAREER CENTER AT WILMINGTON INDUST. Local ID:
Street Address: 62 LAUREL DR. City: Wilmington
State: Ohio Zip Code: County: Clinton
Location Description: Monitoring Point Location Setting: Rural
Coll. Method: Interpolation-Map Land Use: Commercial
Date Established: 19930401 Date Terminated: Last Updated: 20060510
Regional Eval. Date: HQ Eval. Date: AQCR : Wilmington-Chillicothe-Logan
CBSA: Wilmington, OH CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Dist to Met. Site(m): EPA Region: Chicago
Not in an urban area
City Population: 11921 Dir. to CBD: SE Dist. to City(km): 4
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.430000 Site Longitude: - 83.788611 Time Zone: Eastern
UTM Zone: 17 UTM Northing: 4367981 UTM Easting: 259981
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 327.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

MONITORING SHELTER LOCATED AT THE WILMINGTON CAREER CENTER

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
OTHER	1
SLAMS	1

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Ohio EPA, Southwest District Office	19930401	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	LAUREL DRIVE	50	1988		LOCAL ST OR HY	SE

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0001 Site Name: CINCI. MAIN POST OFFICE Local ID:
Street Address: 800 VINE ST. City: Cincinnati
State: Ohio Zip Code: 45202 County: Hamilton
Location Description: Monitoring Point Location Setting: Urban And Center City
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19570101 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: Dist. to City(km): 0
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.104722 Site Longitude: - 84.513611 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4331130 UTM Easting: 715010
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 192.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

THE DOWNTOWN FEDERAL BUILDINGI

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	1

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19570101	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	VINE ST.	8900	1997		LOCAL ST OR HY	W
2	9TH ST.	4980	2006		LOCAL ST OR HY	N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0006 Site Name: HAMILTON COUNTY ODOT OUTPOST 'SYCAMORE' Local ID:
Street Address: 11590 GROOMS RD City: Cincinnati
State: Ohio Zip Code: 45242 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19691003 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: 19910426 AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: SW Dist. to City(km): 23.3
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.278499 Site Longitude: - 84.365974 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4350770 UTM Easting: 727210
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 259.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

RALSTON PURINA - 5.4 KM - 99 DEG., FORD SHARONVILLE 5.3 KM - 105 0 FORMICA - 6.5 KM - 238 DEG., OZONE 6/75 CO 8/75 TSP 6/75

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
INDEX SITE	1
SLAMS	4

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19691003	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	GROOMS RDS	4357	2004		THRU ST OR HY	W
2	I-275	115350	2002		FREEWAY	NNE
3	ODOT ENTRANCE RD.	100	1992		LOCAL ST OR HY	N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0006 Site Name: HAMILTON COUNTY ODOT OUTPOST 'SYCAMORE' Local ID:
Street Address: 11590 GROOMS RD City: Cincinnati
State: Ohio Zip Code: 45242 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19691003 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: 19910426 AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: SW Dist. to City(km): 23.3
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.278499 Site Longitude: - 84.365974 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4350770 UTM Easting: 727210
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 259.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
4	KEMPER ROAD	19000	2000		THRU ST OR HY	N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0010 Site Name: COLERAIN Local ID:
Street Address: 6950 RIPPLE RD. City: Cleves
State: Ohio Zip Code: 45002 County: Hamilton
Location Description: Monitoring Point Location Setting: Rural
Coll. Method: Interpolation Land Use: Industrial
Date Established: 19780101 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 2790 Dir. to CBD: SW Dist. to City(km): 8.1
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.214931 Site Longitude: - 84.690723 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4342958 UTM Easting: 699374
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 158.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

MIAMITOWN CO. HIGHWAY MAINTENANCE BLDG

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	3

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19780101	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	I-74	78950	2002		ARTERIAL	S
2	HARRISON AVE.	11700	2000		FREEWAY	N
3	RIPPLE ROAD	200	1991		LOCAL ST OR HY	W

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0014 Site Name: CARTHAGE Local ID:
Street Address: SEYMOUR & VINE ST. City: Cincinnati
State: Ohio Zip Code: 45216 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Industrial
Date Established: 19691101 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: 19910426 AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: S Dist. to City(km): 10.5
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.194167 Site Longitude: - 84.478889 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4341145 UTM Easting: 717720
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 163.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

CARTHAGE FIRE HOUSE

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
OTHER	1
QA COLLOCATED	1
SLAMS	77

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19691101	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	VINE ST.	11800	1998		THRU ST OR HY	E
2	SEYMOUR	7950	1998		THRU ST OR HY	S

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0014 Site Name: CARTHAGE Local ID:
Street Address: SEYMOUR & VINE ST. City: Cincinnati
State: Ohio Zip Code: 45216 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Industrial
Date Established: 19691101 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: 19910426 AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: S Dist. to City(km): 10.5
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.194167 Site Longitude: - 84.478889 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4341145 UTM Easting: 717720
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 163.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
3	I-75	161250	2002		EXPRESSWAY	W

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0021 | Site Name: FEDERAL BLDG. | Local ID:
Street Address: 100 E. 5TH ST. | City: Cincinnati
State: Ohio | Zip Code: 45202 | County: Hamilton
Location Description: Monitoring Point | Location Setting: Urban And Center City
Coll. Method: Interpolation | Land Use: Commercial
Date Established: 19810201 | Date Terminated: | Last Updated: 20091217
Regional Eval. Date: | HQ Eval. Date: 19910426 | AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN | CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN | Direct Met Site: | Met. Site ID:
Type Met Site: | Local Region:
Urban Area: Cincinnati, OH-KY | Dist to Met. Site(m): | EPA Region: Chicago
City Population: 331285 | Dir. to CBD: W | Dist. to City(km): 1
Census Block: | Block Group: | Census Tract:
Congressional District: | Class 1 Area:
Site Latitude: +39.101944 | Site Longitude: - 84.509722 | Time Zone: Eastern
UTM Zone: 16 | UTM Northing: 4330845 | UTM Easting: 715340
Accuracy: 12 | Datum: NAD27 | Scale: 24000 | Point/Line/Area: Point
Vertical Measure(m): 168.0 | Vert Accuracy: 1
Vert Datum NGVD29 | Vert Method: Topographic Map Interpolation

SITE COMMENTS

SIDE ROOF OF FEDERAL BUIILDING, FOUNTAIN SQUARE

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	1

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19810201	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	FIFTH ST.	17250	2001		LOCAL ST OR HY	S
2	MAIN ST.	10600	2001		LOCAL ST OR HY	E
3	WALNUT ST.	10000	2002		LOCAL ST OR HY	W

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0040 Site Name: HC-DOES OFFICES Local ID:
Street Address: 250 WM. HOWARD TAFT City: Cincinnati
State: Ohio Zip Code: 45219 County: Hamilton
Location Description: Monitoring Point Location Setting: Urban And Center City
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19990401 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: S Dist. to City(km): 3
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.128611 Site Longitude: - 84.504167 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4333840 UTM Easting: 715745
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 256.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

FOMER MEDICAL BUILDING NOW THE OFFICES OF HAMILTON COUNTY DEPARTMENT OF ENVIRONMENTAL SERVICES

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SUPLMNTL SPECIATI	61
SLAMS	11

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	19990401	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	WM. HOWARD TAFT RD	19000	2006		MAJ ST OR HY	S
2	HIGHLAND AVE.	8800	1997		LOCAL ST OR HY	E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0041
Site Name:
Local ID:
Street Address: 5300 WINNESTE AVE.
City: Cincinnati
State: Ohio
Zip Code: 45232
County: Hamilton
Location Description: Monitoring Point
Location Setting: Urban And Center City
Coll. Method: Interpolation-Map
Land Use: Industrial
Date Established: 19980901
Date Terminated:
Last Updated: 20080709
Regional Eval. Date:
HQ Eval. Date:
AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN
CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN
Direct Met Site:
Met. Site ID:
Type Met Site: On-Site Met Equip
Local Region:
Urban Area: Cincinnati, OH-KY
Dist to Met. Site(m):
EPA Region: Chicago
City Population: 331285
Dir. to CBD: N
Dist. to City(km): 4
Census Block:
Block Group:
Census Tract:
Congressional District:
Class 1 Area:
Time Zone: Eastern
Site Latitude: +39.185967
Site Longitude: - 84.513719
UTM Easting: 714746
UTM Zone: 16
UTM Northing: 4340152
Scale: 24000
Point/Line/Area: Point
Accuracy: 12
Datum: NAD27
Vert Accuracy: 1
Vertical Measure(m): 198.0
Vert Method: Topographic Map Interpolation
Vert Datum NGVD29

SITE COMMENTS

WINTON MONTESSORI SCHOOL

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SPECIAL PURPOSE	15
OTHER	47

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	19980901	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	WINNESTE	6800	1997		LOCAL ST OR HY	W
2	HOLLAND	3000	1999		LOCAL ST OR HY	E
3	STRAND	3000	1999		LOCAL ST OR HY	N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0042 Site Name: LOWER PRICE HILL F.S. NO. 17 Local ID:
Street Address: 2101 W. 8TH ST. City: Cincinnati
State: Ohio Zip Code: 45204 County: Hamilton
Location Description: Monitoring Point Location Setting: Urban And Center City
Coll. Method: Interpolation Land Use: Residential
Date Established: 20001003 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: E Dist. to City(km): 2.7
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.105000 Site Longitude: - 84.551111 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4331076 UTM Easting: 711759
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 167.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

LOWER PRICE HILL FIREHOUSE NO. 17

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	3
SPECIAL PURPOSE	72

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	20001003	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	WEST EIGHT STREET	12514	2005		THRU ST OR HY	N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0043 Site Name: SCARLET OAKS SCHOOL Local ID:
Street Address: 3254 E. KEMPER RD. City: Sharonville
State: Ohio Zip Code: 45241 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Mobile
Date Established: 20001003 Date Terminated: 20081231 Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 13804 Dir. to CBD: SW Dist. to City(km): 22.5
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.290278 Site Longitude: - 84.414444 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4351969 UTM Easting: 722991
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 194.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

SCARLET OAKS CAREER DEVELOPMENT CENTER

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	20001003	20081231

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	KEMPER ROAD	7600	2001		MAJ ST OR HY	S
2	I-275	112480	2006		FREEWAY	S

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0044 Site Name: Local ID:
Street Address: 190 Main Street City: Addyston
State: Ohio Zip Code: 45001 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: GPS Land Use: Residential
Date Established: 20050510 Date Terminated: Last Updated: 20090814
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 1010 Dir. to CBD: Dist. to City(km):
Census Block: 4000 Block Group: 4 Census Tract: 02040
Congressional District: 1 Class 1 Area:
Site Latitude: +39.138374 Site Longitude: - 84.711570 Time Zone: Eastern
UTM Zone: UTM Northing: UTM Easting:
Accuracy: 11 Datum: WGS84 Scale: Point/Line/Area: Point
Vertical Measure(m): 148.0 Vert Accuracy: 5
Vert Datum NGVD29 Vert Method: GPS Carrier Phase Static Relative Position

SITE COMMENTS

VOC SITE

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
INDUSTRIAL	71

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	20050510	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	MAIN STREET	4160	2004		LOCAL ST OR HY	SSW
2	CHURCH STREET				LOCAL ST OR HY	WNW
3	U.S. 50	14033	2004		MAJ ST OR HY	SSW

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-0045 Site Name: Local ID:
Street Address: 745 DERBY AVE. City: Cincinnati
State: Ohio Zip Code: 45232 County: Hamilton
Location Description: Monitoring Point Location Setting: Urban And Center City
Coll. Method: GPS Land Use: Residential
Date Established: 20051001 Date Terminated: Last Updated: 20091009
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 331285 Dir. to CBD: Dist. to City(km):
Census Block: 3003 Block Group: 3 Census Tract: 00730
Congressional District: 1 Class 1 Area:
Site Latitude: +39.170925 Site Longitude: - 84.518663 Time Zone: Eastern
UTM Zone: UTM Northing: UTM Easting:
Accuracy: 11 Datum: WGS84 Scale: Point/Line/Area: Point
Vertical Measure(m): 165.0 Vert Accuracy: 5
Vert Datum NGVD29 Vert Method: GPS Carrier Phase Static Relative Position

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SPECIAL PURPOSE	72

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	20051001	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	DERBY AVENUE	3400	1996		LOCAL ST OR HY	N
2	WINTON ROAD	17745	2006		THRU ST OR HY	W
3	SPRING GROVE AVENUE	24310	2004		MAJ ST OR HY	S

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-5001 Site Name: LOCKLAND CITY HALL Local ID:
Street Address: 101 COOPER AVE. City: Lockland
State: Ohio Zip Code: 45215 County: Hamilton
Location Description: Monitoring Point Location Setting: Urban And Center City
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19691009 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 3707 Dir. to CBD: NW Dist. to City(km): 1
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.226389 Site Longitude: - 84.453889 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4344790 UTM Easting: 719800
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 175.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

ROOF OF LOCKLAND FIRE HOUSE

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
QA COLLOCATED	1
SLAMS	1

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19691009	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	WYOMING AVE.	4575	2004		THRU ST OR HY	SE
2	N. COOPER AVE.	2000	1992		LOCAL ST OR HY	E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-7001 Site Name: NORWOOD Local ID:
Street Address: 2059 SHERMAN AVE. City: Norwood
State: Ohio Zip Code: 45212 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Commercial
Date Established: 19730104 Date Terminated: Last Updated: 20091217
Regional Eval. Date: HQ Eval. Date: 19810504 AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 21675 Dir. to CBD: S Dist. to City(km): 1
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.160000 Site Longitude: - 84.457778 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4337425 UTM Easting: 719655
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 194.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

ON ROOF OF HEALTH CENTER

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	3

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19730104	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	SHERMAN AVE.	13050	2002		THRU ST OR HY	N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-061-8001 Site Name: Local ID:
Street Address: 300 MURRAY RD. City: St. Bernard
State: Ohio Zip Code: 45217 County: Hamilton
Location Description: Monitoring Point Location Setting: Suburban
Coll. Method: Interpolation Land Use: Industrial
Date Established: 19701002 Date Terminated: 20100207 Last Updated: 20100413
Regional Eval. Date: HQ Eval. Date: 19910426 AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN Direct Met Site: Met. Site ID:
Type Met Site: Local Region:
Urban Area: Cincinnati, OH-KY Dist to Met. Site(m): EPA Region: Chicago
City Population: 4924 Dir. to CBD: SW Dist. to City(km): 2
Census Block: Block Group: Census Tract:
Congressional District: Class 1 Area:
Site Latitude: +39.180278 Site Longitude: - 84.491944 Time Zone: Eastern
UTM Zone: 16 UTM Northing: 4339600 UTM Easting: 716645
Accuracy: 12 Datum: NAD27 Scale: 24000 Point/Line/Area: Point
Vertical Measure(m): 161.0 Vert Accuracy: 1
Vert Datum NGVD29 Vert Method: Topographic Map Interpolation

SITE COMMENTS

ON THE ROOF OF HERBERT CHEMICAL COMPANY

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Southwestern Ohio Air Pollution Control Agency	19701002	19920816
SUPPORTING	Hamilton County Department Of Environmental Services	19920817	20100207

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	VINE ST.	11800	1998		THRU ST OR HY	W
2	MURRAY RD.	1500	1992		LOCAL ST OR HY	S

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
SITE DESCRIPTION REPORT

Sep. 20, 2010

Site ID: 39-165-0007
Site Name:
Local ID:
Street Address: 416 SOUTHEAST ST.
City: Lebanon
State: Ohio
Zip Code: 45036
County: Warren
Location Description: Monitoring Point
Location Setting: Suburban
Coll. Method: Interpolation
Land Use: Residential
Date Established: 20030514
Date Terminated:
Last Updated: 20091217
Regional Eval. Date:
HQ Eval. Date:
AQCR : Metropolitan Cincinnati
CBSA: Cincinnati-Middletown, OH-KY-IN
CSA: Cincinnati-Middletown-Wilmington, OH-KY-IN
Direct Met Site:
Met. Site ID:
Type Met Site:
Local Region:
Urban Area: Cincinnati, OH-KY
Dist to Met. Site(m):
EPA Region: Chicago
City Population: 16962
Dir. to CBD: N
Dist. to City(km): .5
Census Block:
Block Group:
Census Tract:
Congressional District:
Class 1 Area:
Time Zone: Eastern
Site Latitude: +39.427797
Site Longitude: - 84.202208
UTM Easting: 740825
UTM Zone: 16
UTM Northing: 4367790
Scale: 24000
Point/Line/Area: Point
Accuracy: 12
Datum: NAD27
Vert Accuracy: 5
Vertical Measure(m): 234.0
Vert Method: Topographic Map Interpolation
Vert Datum NGVD29

SITE COMMENTS

IN A COMPLEX OF WARREN COUNTY ADMINISTRATION BUILDINGS

ACTIVE MONITOR TYPES

Monitor Type	# of Monitors
SLAMS	5

AGENCY ROLES

Role	Agency Desc	Begin Date	End Date
SUPPORTING	Hamilton County Department Of Environmental Services	20030514	

TANGENT ROADS

Road Number	Road Name	Traffic Count	Traffic Year	Traffic Volume Source	Road Type	Compass Sector
1	EAST STREET	2859	2006		MAJ ST OR HY	W
2	JUSTICE DRIVE	500	2002		LOCAL ST OR HY	S

Appendix D

Base Year and

Projected Emission Inventory

Technical Support Documents (TSD)

Emissions Inventory Assistance: 2005 Base Year

Biogenic and Other (non-LADCO) State Emissions

Preparation and Delivery of Non-MRPO

Emission Files

Prepared for:

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12 March 2007

Table of Contents

Acronyms and Abbreviations

CENRAP	Central Regional Air Planning Association
CMV	Commercial Marine Vessels
CE	Control Efficiency
EPA	Environmental Protection Agency
EGU	Electric Generating Unit
FTP	File transfer protocol
IDA	Inventory Data Analyzer
MANE-VU	Mid-Atlantic/Northeast Visibility Union
NH_3	Ammonia
NIF	National Emission Inventory Format
NMIM	National Mobile Inventory Model
NONROAD	no acronym (model name)
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions Model
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
WRAP	Western Regional Air Partnership

Introduction

The Lake Michigan Air Directors Consortium (LADCO) States are conducting photochemical modeling to support the development of State Implementation Plans (SIPs) for ozone, PM2.5, and regional haze. A new round of modeling is planned with a more recent base year (2005). To support this modeling, an emissions inventory for 2005 (and relevant future years – 2009 and 2018) is needed on an expeditious schedule.

To address this need, Alpine Geophysics (Alpine) and MACTEC have teamed together to deliver and prepare a number of base and projection year emission files for regional planning organizations outside of the Midwest state domain. These RPOs include the Mid-Atlantic/Northeast Visibility Union (MANE-VU), Visibility State and Tribal Association of the Southeast (VISTAS), Central Regional Air Planning Association (CENRAP), and Western Regional Air Partnership (WRAP). Alpine and MACTEC were uniquely qualified to provide these files having already prepared or obtained base year and emission projections for each of these RPOs under other contracts.

Through other contracts recently completed or currently in place with the Alpine/MACTEC Team, 2002, 2005, 2009, and 2018 emission inventories (in NIF3.0 or SMOKE IDA format) were in-house for each of the non-LADCO States and for each of the major source sectors (EGU, non-EGU point, stationary area, nonroad MAR, NONROAD sources, and onroad activity and input files). These data sets were either developed directly by the Study Team (VISTAS and MANE-VU all years, CENRAP 2009, WRAP 2009) or obtained directly from the RPOs for processing emissions on the national 36km domain.

1.0 Provision of Unmodified Files

1.1 EGU, Non-EGU and Stationary Area Sources for MANE-VU and VISTAS

Several of the required files required no additional work other than to compile the files and make them available to LADCO for their use. MACTEC gathered the EGU, non-EGU, and stationary area source files for both MANE-VU and VISTAS and placed them on the AirToxics FTP site as delivery to LADCO. No modifications of these files were made. Files delivered included EGU, non-EGU and stationary area source files for 2002, 2009 and 2018 for VISTAS and MANE-VU. Each of these files was in National Inventory Format (NIF) version 3.0. In addition, each of these files contained the annual emissions estimates only and did not provide seasonal emission estimates.

2.0 Provision of Modified Files

2.1 Nonroad

As part of the proposal provided to LADCO by MACTEC and AG, the team had indicated that while not prepared in this manner, seasonal and monthly emission estimates for the nonroad sector (excluding commercial marine, aircraft and railroads – [MAR]) could be prepared from the NONROAD05/NMIM model runs used to develop these emissions. In addition the team had indicated that 2005 emission estimates at the seasonal/monthly level could also be created from these runs by interpolation of the 2002 and 2009 files. This section describes the development of the nonroad emission files for 2002, 2005, 2009 and 2018 for each RPO. The development of the 2002, 2005, 2009 and 2018 MAR component of the inventory at an annual level is described. The temporal level developed varied by RPO.

For VISTAS and the WRAP, the initial and resulting modeling files had been prepared at the seasonal level, thus only seasonal estimates were prepared for this work. For MANE-VU, the initial annual estimates had been prepared using NMIM which generates estimates at a monthly level. Thus MANE-VU estimates were developed at the monthly level. CENRAP emissions were available at an annual level and therefore provided as such. The approaches used for each RPO are described below.

2.1.1 Development of MANEVU Monthly Nonroad Estimates

As indicated above, the original annual NIF files prepared for MANE-VU for NONROAD model sources were developed using the NMIM model, with the exception of emissions for 2002 from Maine and the District of Columbia, which were prepared using the NONROAD model. For 2009 and 2018, all NONROAD model sources were estimated using NMIM. MACTEC's

task was to convert the raw files developed from NMIM into monthly emissions in NIF format for 2002, 2009 and 2018. From those files, MACTEC would then use the 2002 and 2009 files to provide an interpolation of emissions to obtain an estimate for 2005.

NMIM output is stored in MySQL database tables. The first step was to obtain the raw output in MySQL. Since MACTEC had prepared the 2009 and 2018 files for MANE-VU those tables were already in-house. However another contractor prepared the 2002 estimates for MANE-VU. MACTEC/AG contacted MANE-VU and obtained the MySQL data tables for the 2002 NMIM run for MANE-VU. However, since Maine and the District of Columbia 2002 emissions were not developed using NMIM, we also obtained the 2002 annual estimates in NIF format. These annual estimates were later converted to monthly estimates. Details on that conversion are described later in this section.

The native output of the NMIM model is to produce monthly emissions. Thus the MySQL tables already contained the monthly emission estimates. However the MySQL format is not NIF 3.0. To obtain NIF 3.0 format, the reporting tool in NMIM must be used to generate monthly emissions. MACTEC used the MySQL tables from the 2002, 2009 and 2018 emission projections along with the NMIM reporting tool to format the data into NIF 3.0 format. These files are TXT format files that correspond to the CE, EM, EP, PE and TR tables in the NIF format. Once the files were output into TXT format, MACTEC used the NIF version 3.0 Microsoft Access database shell to import the files into Microsoft Access for additional manipulation and in order to perform quality assurance checks on the data. Output

2.1.1.1 Conversion of 2002 Annual Emissions for ME and DC to Monthly

As mentioned above, the 2002 NMIM MySQL tables did not include Maine and the District of Columbia since they were estimated using NONROAD05. As a consequence, before a 2005 estimate could be prepared, the annual ME and DC estimates had to be converted to monthly values. In order to do this, MACTEC developed MANE-VU wide monthly fractions from the 2002 file. These fractions were then applied to the annual values for DC and ME to obtain a monthly record from the annual value. Monthly entries for each pollutant for the EM table were generated from an average monthly fraction from all other MANE-VU States for 2002. In addition, monthly records were added to the PE table.

2.1.1.2 Calculation of the 2005 Estimates for MANE-VU

Once DC and ME monthly emissions had been calculated and added to the monthly emissions available for the other MANE-VU States from the NMIM runs, the remaining step was to calculate 2005 emissions based on an interpolation of emissions between 2002 and 2009. In order to calculate these emissions the State, County, SCC and Pollutant in each EM table was

matched in 2002 and 2009. In doing this, MACTEC identified that there were over 700 records in the 2009 file that did not exist in the 2002 file. All of these records were for DC and ME and all were for the pollutant NH3. As a consequence, MACTEC decided to add the 2009 records to the 2002 file for these missing records with no change in emissions levels. The records are marked in the database using one of the BLANK fields in the EM table. Thus they can be easily identified.

Once the records matched between 2002 and 2009 at the State, County, SCC and Pollutant level, the interpolated emissions were calculated. The calculation was as follows:

$$((2009 - 2002) * (3/7)) + 2002$$

Where:

2002	=	2002 emissions
2009	=	2009 emissions
3/7	=	multiplier to determine 2005 emissions as a linear interpolation between 2002 and 2009

Once the 2005 emissions were calculated, appropriate changes were made to the EM, PE and TR table to reflect a 2005 emission inventory year. In addition, a similar calculation was applied to throughput values in the PE table.

Finally, when all changes to the Access tables had been made, the NIF tables were exported into TXT format, compressed using WinZip and placed on AG's FTP site for delivery to LADCO.

2.1.2 Development of VISTAS Seasonal Nonroad Estimates

VISTAS seasonal estimates were prepared in a similar manner to the MANE-VU monthly estimates. In the preparation of the 2002, 2009 and 2018 files for VISTAS, the NONROAD05 model had been utilized to estimate seasonal emissions. During preparation of the annual NIF files the fractions for each season found in the EP table were determined from the seasonal emissions calculated by the NONROAD05 runs. Thus the seasonal percentages in the annual files in the EP table were not based on defaults but were based on actual calculated seasonal emissions. As a consequence, these seasonal percentages were used to calculate seasonal emissions for 2002, 2009 and 2018.

Thus to calculate seasonal emissions, the annual value was multiplied by the seasonal percentage to obtain a seasonal value for winter, spring, summer and fall.

However, because the winter season includes December, January and February, two entries for the EM and PE tables were prepared for winter estimates, one for December and one for the January through February portion. In order to calculate these separate values, the number of days of the total season in each of these portions was used to apportion the winter season emissions to each entry. For example, the winter season for each year (none of which are leap years) contains 90 days total (31 in December, 31 in January and 28 in February). Thus to get the December winter value, the annual emission value was multiplied by the winter seasonal fraction and by 31/90 (the number of days in December divided by the total number of days in the season). Similarly for the Jan/Feb entry the annual value was multiplied by the seasonal percentage and by 59/90 (the number of days in Jan/Feb and the total number of days in the season). Matching seasonal records for each entry were added to the PE table and seasonal throughput values were calculated in a similar manner.

2.1.3 Development of CENRAP/WRAP Nonroad Estimates

As part of their responsibilities for other modeling conversion contracts, Alpine staff have converted emission inventories and associated emissions modeling files into a variety of formats, including NIF 3.0, SMOKE IDA, and RPO Data Exchange Protocol. Our proposed and approved method was to use the same procedures and scripts used to convert the emission files from those contracts in the conversion to the NIF data format in this study. Emissions as provided on temporal scales (annual, seasonal, or daily) were used to populate the NIF emission fields in the converted file.

Nonroad emission files for CENRAP and WRAP were converted and aggregated into a single nonroad series of NIF tables for each year of conversion (2002, 2009, and 2018). Within each EM table provided per year, annual, seasonal, and daily emission periods exist, based on the original obtained modeling file from the individual RPO.

Our quality assurance in this task was dedicated to the assertion that the reformatting of these data did not invalidate the integrity of the original inventories. As such, QA on these files included the comparison of reformatted data to the original SMOKE IDA files ensuring that specific required fields had been appropriately converted to the field type, length, and unit requirements of the NIF structure.

2.1.3.1 Calculation of the 2005 Estimates for other RPOs

2005 emission values were calculated for VISTAS, CENRAP, and WRAP using the same equation as in section 2.1.1.2. Values for 2002 and 2009 were interpolated to obtain a 2005 value for temporal allocation available for the RPO.

2.2 MAR

For each of the non-MRPO RPOs, 2002, 2009 and 2018 estimates for MAR sources were provided at the annual level. The MAR estimates were provided by extracting all MAR sources from the annual nonroad files which contained annual emissions from both MAR and NONROAD model sources. Appropriate records from the CE, EM, EP and PE tables were extracted and placed into an Access database solely containing MAR emissions. Once the files were compiled they were then used to calculate 2005 MAR emissions.

For CENRAP and WRAP emissions, additional conversions were made to convert SMOKE IDA formatted files into the NIF 3.0 structure as noted in the sections above. These emissions for MAR sources are included for these two RPOs in the nonroad emission converted files.

2.2.1 Development of 2005 MAR Emissions

The 2005 MAR emissions were calculated using the 2002 and 2009 emissions and performing a straight line interpolation of emissions using the same equation as provided in section 2.1.1.2. This approach was also used on the CE table control efficiencies. While the NONROAD model sources did not contain any CE entries (NMIM does not generate any CE table entries), CE tables did contain some entries in a few of the RPO reported files. These values were given a straight line interpolation using the equation in section 2.1.1.2.

2.3 EGU Point Source Files

Electric generating utility (EGU) point source files have been prepared by RPOs using a variety of methods. For base year emissions data, CEM emissions and heat input values are used to derive inventories and other unit level characteristics for modeling. Recently, ICF's proprietary Integrated Planning Model (IPM) has been utilized by many of the RPOs to derive future year emission estimates for this source category. In this project, both types of data were obtained from the RPOs and converted to the NIF 3.0 format for LADCO's modeling needs.

2.3.1 2002, 2009, and 2018 EGU Emissions for CENRAP/WRAP

EGU point source emissions files for CENRAP and WRAP RPOs were obtained for 2002, 2009 and 2018 in SMOKE IDA format. Identical to the methods identified above, these files were translated to the NIF 3.0 format for this project. For both RPOs and all years, annual emission estimates were available in the modeling files and were converted to NIF annual emission records.

Similar to the other SMOKE to NIF file conversions, our quality assurance in this task was dedicated to the assertion that the reformatting of these data did not invalidate the integrity of the original inventories. As such, QA on these files included the comparison of reformatted data to

the original SMOKE IDA files ensuring that specific required fields had been appropriately converted to the field type, length, and unit requirements of the NIF structure.

2.3.2 2005 EGU Emissions

EGU point source emissions files for 2005 for all the non-LADCO RPOs were developed under separate contract by Alpine using CEM reported emissions, heat input, and control characteristics. For the CEM reported pollutants NOx and SO2, emissions were taken directly from the reported values when available. For non-CEM pollutants, the CEM reported heat input was applied to 2002 calculated emission rates (from the original RPO 2002 base year EGU files) to estimate annual emissions from these pollutants. In cases where it was determined that incremental controls had been applied between the 2002 and 2005 base year, control efficiencies (as noted by EPA documentation) were assigned to the unit and emission reductions were calculated accordingly. For units which were new in 2005 (and not found in 2002 or 2009 emission inventories), methods established by EPA and published on the NEI development website were used to prepare emission estimates and other unit level characteristics for these sources. In contrast to the 2002 EGU emissions provided by the RPOs and noted in the previous section, the EGU file for 2005 contains only emission sources which reported under the CEM program and were found in the EPA CEM databases.

Identical to the conversion methods identified for other source sectors, these files were translated to the NIF 3.0 format for this project. For all 2005 EGU emission sources, annual emission estimates were available and were converted to NIF annual emission records.

Similar to the other SMOKE to NIF file conversions, our quality assurance in this task was dedicated to the assertion that the reformatting of these data did not invalidate the integrity of the original inventories. As such, QA on these files included the comparison of reformatted data to the original SMOKE IDA files ensuring that specific required fields had been appropriately converted to the field type, length, and unit requirements of the NIF structure.

2.4 Non-EGU Point and Stationary Area Source Files

Non-EGU point and stationary area source emissions files for CENRAP and WRAP RPOs were obtained for 2002, 2005, 2009 and 2018 in SMOKE IDA format. Using methods already established by Alpine for projects of emission conversion for EPA, the RPOs, and other clients, these files were translated to the NIF 3.0 format for this project. For both RPOs and all years, annual emission estimates were available in the modeling files and were converted to NIF annual emission records. The exception to annual emissions reporting was for some fugitive dust related categories in CENRAP and WRAP domains (road dust, agricultural dust, etc.) where seasonal emission files in IDA format were provided. In these instances, the seasonal temporal variability

was maintained in the conversion and appropriate seasonal emission records were developed for the NIF CE tables.

Non-EGU point source files were prepared by subtracting out the EGU emissions portion as estimated and noted in section 2.3 above. For 2002, 2009, and 2018, this was based on EGU files provided directly from the RPOs. For 2005, this subtraction was based on Alpine review of 2005 CEM-reporting emission sources and removal of CEM reporting units from the non-EGU file.

Similar to the nonroad file conversion, our quality assurance in this task was dedicated to the assertion that the reformatting of these data did not invalidate the integrity of the original inventories. As such, QA on these files included the comparison of reformatted data to the original SMOKE IDA files ensuring that specific required fields had been appropriately converted to the field type, length, and unit requirements of the NIF structure.

2.5 Quality Assurance Steps

For the emission estimates and data conversions described above, the following quality assurance (QA) steps were performed:

1. Sample calculations were checked by hand including database calculations. Database calculations were performed using a SELECT query before performing an UPDATE query to change values
2. Total region-wide seasonal/monthly emission estimates were checked to compare to annual region-wide estimates at the pollutant level to ensure that values closely matched.
3. In most cases, the EPA Basic Format and Content Checker tool was used to QA the databases developed prior to export of the files to TXT format. In a few cases this could not be performed due to the large size of the databases (the VISTAS seasonal database contained over 8 million records in the EM table alone). In all cases at least one of the databases was checked with the tool, however.
4. Summaries of emissions at the State/County/SCC/pollutant level were developed to compare 2002, 2005 and 2009 values.
5. Confirmed that the reformatting of these data did not invalidate the integrity of the original inventories.
6. We compared RPO provided emission summaries to the emission summaries generated from the reformatted (NIF 3.0) data sets to ensure that all emissions have been accounted for in the conversion process.

DEVELOPMENT OF 2005 BASE YEAR GROWTH AND CONTROL FACTORS FOR LAKE MICHIGAN AIR DIRECTORS CONSORTIUM (LADCO)

FINAL REPORT

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September 2007

Pechan Report No. 07.09.001/9458.000

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CONTENTS

TABLES

ACRONYMS AND ABBREVIATIONS

AEO	*Annual Energy Outlook*
AIM	architectural and industrial maintenance
BART	best available retrofit technology
CE	control efficiency
CMV	commercial marine vessel
DEQ	Department of Environmental Quality
DOE	Department of Energy
EGAS	Economic Growth Analysis System
EGU	electric generating unit
EPA	United States Environmental Protection Agency
FAA	Federal Aviation Administration
FCCUs	fluid catalytic cracking units
FCU	fluid coking units
FGR	flue gas recirculation
HAP	hazardous air pollutant
IC	internal combustion
LADCO	Lake Michigan Air Directors Consortium
LAER	lowest achievable emission rate
LNB	low NO_x burner
MACT	maximum achievable control technology
MAR	marine, aircraft, and railroad
MSAT	mobile source air toxics
NAAQS	national ambient air quality standards
NH3	ammonia
NMIM	National Mobile Inventory Model
NO_x	oxides of nitrogen
NSPS	new source performance standard
OTB	on-the-books
OWB	outdoor wood boiler
Pechan	E.H. Pechan & Associates, Inc.
PFC	portable fuel container
PM	particulate matter
PM-2.5	particulate matter less than or equal to 2.5 micrometers
RACT	reasonably available control technology
RE	rule effectiveness
REMI	Regional Economic Models, Inc.
RIA	Regulatory Impact Analysis
RICE	reciprocating internal combustion engines
ROG	reactive organic gases
RP	rule penetration
RPO	Regional Planning Organization
SCC	source classification code

SIC	standard industrial classification
SIP	State Implementation Plan
tpy	tons per year
SO_2	sulfur dioxide
VOC	volatile organic compound

SECTION I. BACKGROUND

E.H. Pechan & Associates, Inc. (Pechan) is supporting the Lake Michigan Air Directors Consortium's (LADCO) efforts to forecast anthropogenic emissions for the purpose of assessing progress for air quality goals, including goals related to regional haze and attainment of the ozone national ambient air quality standards (NAAQS). Under a previous contract with LADCO, Pechan prepared emission activity growth and emission control data for all non-electric generating unit (EGU) point, area, and nonroad source categories relative to a base year (2002) inventory supplied by LADCO. In December 2004, Pechan submitted emissions activity growth and control factor files for use by LADCO in emissions modeling. A December 14, 2004 Pechan report documents the contents and derivation of these files (Pechan, 2004). Revised files were later provided to LADCO in March 2005.

In September 2005, LADCO contracted with Pechan to conduct the following two tasks to develop updated growth and control factors needed to support future year control strategy analyses for regional haze, particulate matter less than or equal to 2.5 micrometers (PM-2.5), and ozone:

Task 1: Update control factors to reflect current information pertaining to:
- (a) Petroleum refinery cases and settlements;
- (b) Maximum achievable control technology (MACT) standard control efficiency assumptions;
- (c) Residential wood combustion unit lifetime; and
- (d) Regional Planning Organization (RPO) inventories.

Task 2: Develop non-EGAS default-based emission activity growth factors for:
- (a) Priority point source categories; and
- (b) Priority area source categories.

A December 2005 report describes Pechan efforts to perform these tasks, which resulted in updated emissions activity growth and control factor files (Pechan, 2005). The updates reflect the use of more recent and/or more detailed information than that used in the earlier study. As with the earlier study, this effort involved the preparation of emission activity growth and control information relative to a 2002 base year inventory for future years of interest. Control information was developed for 2007, 2008, 2009, 2012, and 2018 (e.g., 2018 is the first milestone for regional haze reasonable progress demonstrations). Because the incremental level of effort required to develop emission activity growth factors for each year over the 2003-2018 period was nominal, Pechan prepared non-EGU point and area and nonroad source growth factors for each year over this entire period.

For the current study, LADCO requested that Pechan develop growth and control factor files to support emission projections from a recently compiled 2005 base year inventory for the following LADCO states: Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. LADCO requested that Pechan provide files representing changes in emission activity and emission control between the base year and 2009, 2012, and 2018. As with the previous studies, Pechan provided updated point/area source and marine, aircraft, and railroad (MAR) category

growth factors for each year over the 2006-2018 period. Control factor development focused on the modeling years of interest, or in the case of point source controls, the specific anticipated implementation date within the forecast period.

This report is organized into this Background section and:

- Section II, which describes the development of the emission activity growth data;
- Section III, which discusses how the updated emission control data were compiled;
- Section IV, which describes the preparation of the updated growth and control factor files; and
- Section V, which presents the references consulted in preparing this report.

SECTION II. EMISSION ACTIVITY GROWTH DATA

A. OVERVIEW

As with the two previous studies, Pechan relied on the data incorporated into Version 5.0 of the Economic Growth Analysis System (EGAS) as the default growth factor data source.[1] The EGAS 5.0 projections data are typically derived from two main resources: (1) version 5.5 of Regional Economic Models Incorporated (REMI)'s state-level economic models; and (2) the Department of Energy (DOE)'s *Annual Energy Outlook (AEO) 2004*. While socioeconomic growth indicators from the REMI models provide state-level growth rates, the DOE energy forecasts provide regional or national growth rates (e.g., the same growth rate is applied to each LADCO state because each of these states is included in the DOE's East North Central division). Instead of relying on REMI's population forecasts, Pechan developed growth factors from county-level population projections available from each LADCO region state.

LADCO requested that Pechan review the growth indicators applied to particular source classification codes (SCCs) in the 2005 base year inventory. For these "priority" source categories, Pechan evaluated alternative growth methodologies and data sources before selecting a forecasting approach. The balance of this section describes the emission activity growth data developed in this study. Section IV discusses how these data were compiled into the file format required by LADCO.

B. AREA SOURCE/MAR CATEGORIES

LADCO provided Pechan with a list of priority point/area source and MAR categories for which emission activity projection improvements were to be evaluated. For these source categories, Pechan reviewed U.S. Environmental Protection Agency (EPA) SCC documentation and emission estimation guidance to identify the emissions activity (throughput) data associated with each SCC. Pechan then investigated the availability of LADCO state-specific projections for these data.

Table II-1 presents the descriptions and emissions activity for each priority area source/MAR category. The last column in this table identifies each category's growth indicator assignment under the previous Pechan forecast effort (Pechan, 2005). Table II-2 displays the assigned growth indicator for each priority area/MAR source category and any alternative indicators that were considered. This table also presents the percentage growth rates for the assigned indicators over two forecast periods: 2005-2009 and 2005-2018.

In addition to population data from the LADCO states and REMI employment data, the following information sources supplied data used in estimating emission activity growth for the priority area source/MAR categories:

[1] Information on these EGAS 5.0 data sources is provided in the report documenting the earliest study Pechan performed for LADCO (Pechan, 2004).

Table II-1. Priority Emission Activity Area Source/MAR Categories

POLLUTANT	SCC	DESC2	DESC3	DESC4	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
NH3	2805047100	Agriculture Production - Livestock	Swine production - deep-pit house operations (unspecified animal	Confinement	Annual average number of swine	REMI Farm sector value added
NH3	2805039200	Agriculture Production - Livestock	Swine production - operations with lagoons (unspecified animal	Manure handling and storage	Annual average number of swine	REMI Farm sector value added
NH3	2805047300	Agriculture Production - Livestock	Swine production - deep-pit house operations (unspecified animal	Land application of manure	Annual average number of swine	REMI Farm sector value added
NH3	2805001100	Agriculture Production - Livestock	Beef cattle - finishing operations on feedlots (drylots)	Confinement	Annual average number of beef cattle	REMI Farm sector value added
NH3	2805039100	Agriculture Production - Livestock	Swine production - operations with lagoons (unspecified animal	Confinement	Annual average number of swine	REMI Farm sector value added
NH3	2805003100	Agriculture Production - Livestock	Beef cattle - finishing operations on pasture/range	Confinement	Annual average number of beef cattle	REMI Farm sector value added
NH3	2805001300	Agriculture Production - Livestock	Beef cattle - finishing operations on feedlots (drylots)	Land application of manure	Annual average number of beef cattle	REMI Farm sector value added
NH3	2630020000	Wastewater Treatment	Public Owned	Total Processed	Volume of wastewater processed	REMI Water and Sanitation sector output
NH3	2805007100	Agriculture Production - Livestock	Poultry production - layers with dry manure management system	Confinement	Annual average number of poultry	Regression with Food/Kindred Products sector value added as explanatory variable
NH3	2805021300	Agriculture Production - Livestock	Dairy cattle - scrape dairy	Land application of manure	Annual average number of dairy cattle	Regression with Farm sector employment as explanatory variable
NH3	2805030000	Agriculture Production - Livestock	Poultry Waste Emissions	Not Elsewhere Classified (see also 28-05-007 -008-009)	Annual average number of poultry	REMI Farm sector value added
NH3	2805021200	Agriculture Production - Livestock	Dairy cattle - scrape dairy	Manure handling and storage	Annual average number of dairy cattle	Regression with Farm sector employment as explanatory variable
NH3	2104008070	Residential	Wood	Outdoor Boiler	Amount of wood burned	
NOX	2285002006	Railroad Equipment	Diesel	Line Haul Locomotives: Class I Operations	Amount of diesel consumed by Class I line-haul locomotives	AEO Freight rail distillate (nat'l) adjusted for relative state growth in REMI Total output
NOX	2280002023	Marine Vessels Commercial	Diesel	Push Boats	Amount of diesel consumed by commercial push boats	AEO Shipping distillate (nat'l) adjusted for relative state growth in REMI Water Transportation sector output
NOX	2102006001	Industrial	Natural Gas	All Boiler Types	Volume of natural gas burned by industrial area source boilers	AEO Industrial natural gas

Table II-1 (continued)

POLLUTANT	SCC	DESC2	DESC3	DESC4	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
NOX	2275020000	Aircraft	Commercial Aircraft	Total: All Types	Number of commercial aircraft landing-takeoff cycles	Federal Aviation Administration (FAA) itinerant air carrier Landing and Take-Off (LTO) forecasts by state
NOX	2285002010	Railroad Equipment	Diesel	Yard Locomotives	Amount of diesel consumed by yard locomotives	AEO Freight rail distillate (nat'l) adjusted for relative state growth in REMI Total output
NOX	2104006000	Residential	Natural Gas	Total: All Combustor Types	Volume of residential natural gas consumed	AEO Residential natural gas
NOX	2285002009	Railroad Equipment	Diesel	Line Haul Locomotives: Commuter Lines	Amount of diesel consumed by commuter locomotives	AEO Commuter rail diesel (nat'l) adjusted for relative growth in population
NOX	2280003200	Marine Vessels Commercial	Residual	Underway emissions	Amount of residual oil consumed by CMV during underway operations	AEO Shipping residual oil (nat'l) adjusted for relative state growth in REMI Water Transportation sector output
NOX	2102006000	Industrial	Natural Gas	Total: Boilers and IC Engines	Volume of natural gas burned by industrial area source boilers and IC engines	AEO Industrial natural gas
NOX	2104008070	Residential	Wood	Outdoor Boiler	Amount of wood burned	
ROG	2461850000	Miscellaneous Non-industrial: Commercial	Pesticide Application: Agricultural	All Processes	(Not listed for this SCC)	Region V employment projections for "Pesticide Handlers, Sprayers"
ROG	2461020000	Miscellaneous Non-industrial: Commercial	Asphalt Application: All Processes	Total: All Solvent Types	Amount of solvent used	Region V employment projections for "Paving, Surfacing, & Tamping Operators"
ROG	2401200000	Surface Coating	Other Special Purpose Coatings	Total: All Solvent Types	Amount of solvent used	Population
ROG	2401001000	Surface Coating	Architectural Coatings	Total: All Solvent Types	Amount of solvent used	Regression with Population (inc. county level) as explanatory variable + projected solvent content change
ROG	2460100000	Miscellaneous Non-industrial: Consumer and Commercial	All Personal Care Products	Total: All Solvent Types	Amount of solvent used	Population (county-level for LADCO states)
ROG	2501011010	Petroleum and Petroleum Product Storage	Portable Gas Cans	Residential	Volume of gasoline stored	REMI, Gas and Oil Expenditures
ROG	2501060100	Petroleum and Petroleum Product Storage	Gasoline Service Stations	Stage 2: Total	Volume of gasoline pumped by stations	Regression with Gas and Oil Expenditures as explanatory variable
ROG	2460800000	Miscellaneous Non-industrial: Consumer and Commercial	All FIFRA Related Products	Total: All Solvent Types	Amount of solvent used	Regression with Population (county-level for LADCO states) as explanatory variable
ROG	2501060050	Petroleum and Petroleum Product Storage	Gasoline Service Stations	Stage 1: Total	Volume of gasoline pumped into stations	REMI, Gas and Oil Expenditures
ROG	2460400000	Miscellaneous Non-industrial: Consumer and Commercial	All Automotive Aftermarket Products	Total: All Solvent Types	Amount of solvent used	Population (county-level for LADCO states)
ROG	2425000000	Graphic Arts	All Processes	Total: All Solvent Types	Amount of solvent used	REMI, Printing and Publishing sector output
ROG	2401005000	Surface Coating	Auto Refinishing: SIC 7532	Total: All Solvent Types	Amount of solvent used	REMI, Automobile Parking, Repair, Services sector output
ROG	2460500000	Miscellaneous Non-industrial: Consumer and Commercial	All Coatings and Related Products	Total: All Solvent Types	Amount of solvent used	Population (county-level for LADCO states)

Table II-1 (continued)

POLLUTANT	SCC	DESC2	DESC3	DESC4	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
ROG	2460200000	Miscellaneous Non-industrial: Consumer and Commercial	All Household Products	Total: All Solvent Types	Amount of solvent used	Population (county-level for LADCO states)
ROG	2415020000	Degreasing	Fabricated Metal Products (SIC 34): All Processes	Total: All Solvent Types	Amount of solvent used	REMI, Fabricated Metals sector employment
ROG	2415025000	Degreasing	Industrial Machinery and Equipment (SIC 35): All Processes	Total: All Solvent Types	Amount of solvent used	REMI, Machinery and Computer Equipment sector employment
ROG	2460600000	Miscellaneous Non-industrial: Consumer and Commercial	All Adhesives and Sealants	Total: All Solvent Types	Amount of solvent used	Population (county-level for LADCO states)
ROG	2420000370	Dry Cleaning	All Processes	Special Naphthas	Amount of special naphthas used	SCC is not in current growth file; similar SCC (2420010370) is in file w/ REMI Laundry sector output
ROG	2630010000	Wastewater Treatment	Industrial	Total Processed	Volume of wastewater processed	Projected LADCO NEEDS industrial flow design forecast
ROG	2501060101	Petroleum and Petroleum Product Storage	Gasoline Service Stations	Stage 2: Displacement Loss/Uncontrolled	Volume of gasoline pumped via uncontrolled	Regression with Gas and Oil Expenditures as explanatory variable
ROG	2415360000	Degreasing	Auto Repair Services (SIC 75): Cold Cleaning	Total: All Solvent Types	Amount of solvent used	REMI, Automobile Parking, Repair, Services sector output
ROG	2401002000	Surface Coating	Architectural Coatings - Solvent-based	Total: All Solvent Types	Amount of solvent used	REMI, Housing expenditures
ROG	2401003000	Surface Coating	Architectural Coatings - Water-based	Total: All Solvent Types	Amount of solvent used	REMI, Housing expenditures
ROG	2104008070	Residential	Wood	Outdoor Boiler	Amount of wood burned	
SO2	2601020000	On-site Incineration	Commercial/Institutional	Total	Amount of material burned	REMI, Commercial sector employment
SO2	2102004000	Industrial	Distillate Oil	Total: Boilers and IC Engines	Amount of distillate oil burned by area source industrial boilers/IC engines	AEO Industrial distillate
SO2	2103004000	Commercial/Institutional	Distillate Oil	Total: Boilers and IC Engines	Amount of distillate oil burned by area source commercial boilers/IC engines	No growth based on historical energy data
SO2	2275020000	Aircraft	Commercial Aircraft	Total: All Types	See NOX entry	FAA itinerant air carrier LTO forecasts by state
SO2	2102005000	Industrial	Residual Oil	Total: All Boiler Types	Amount of residual oil burned by area source industrial boilers	AEO Industrial residual
SO2	2102002000	Industrial	Bituminous/Subbituminous Coal	Total: All Boiler Types	Amount of bit/sub coal burned by area source industrial boilers	AEO Industrial steam coal
SO2	2285002006	Railroad Equipment	Diesel	Line Haul Locomotives: Class I Operations	See NOX entry	AEO Freight rail distillate (nat'l) adjusted for relative state growth in Total output
SO2	2104008070	Residential	Wood	Outdoor Boiler	Amount of wood burned	

Table II-2. Growth Indicators for Priority Area Source/MAR Categories

Pollutant	SCC	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
NH3	2805047100	-1.7	6.2	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805039200	-2.3	4.4	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805047300	-1.6	6.4	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805001100	5.2	16.7	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805039100	-1.6	6.4	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805003100	3.2	3.5	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805001300	5.2	16.7	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2630020000	2.8	9.5	Municipal design flow forecasts from Drinking Water Infrastructure Needs Survey		
NH3	2805007100	-4.5	8.3	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805021300	-10.2	-39.0	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805030000	-5.3	6.8	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2805021200	-10.2	-39.0	Interpolated SCC/state-level animal count projections from EPA NH3 inventory of Animal Husbandry Operations		Forecast data are state-level
NH3	2104008070	78.0	84.3	Extrapolation of national 1999-2004 trend in OWB sales (exponential growth) thru 2006; linear growth thru 2008; 2009+ based on rural population growth rate		
NOX	2285002006	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -1.4% per year; AEO forecast = 1.4% per year	Note that post-2001 trend has been upward and that historical data shows several ups and downs
NOX	2280002023	4.3	9.9	AEO national Domestic Shipping sector distillate projections adjusted for LADCO region growth in REMI Water Transportation sector output relative to nation	1998-2004 fuel consumption data for barge traffic on regional rivers indicates similar annual growth rate (1.0%)	Forecast data are state-level
NOX	2102006001	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -0.01% per year; AEO forecast = 1.4% per year	
NOX	2275020000	0.0	0.0	No growth due to contradictory historic and forecast trends (Federal Aviation Administration commercial aircraft landing and take-offs data)	FAA 1990-2005 = -0.01% per year; FAA forecast = 1.7% per year	
NOX	2285002010	0.0	0.0	No growth due to contradictory historic and forecast trend (historic trend based on 1996-2002 regional Switch and Terminal Services employment)	1996-2004 = -1.6% per year employment decrease; AEO forecast = 1.4% per year	
NOX	2104006000	1.7	2.8	AEO residential natural gas consumption forecast	DOE 1990-2004 = 0.5% annual; AEO forecast = 0.2%	

Table II-2 (continued)

Pollutant	SCC	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
NOX	2285002009	7.4	26.1	Annual growth rate (1.8%) from 2005-2009 diesel fuel consumption projections reported in Marta 2007 budget		
NOX	2280003200	0.4	1.3	1995-2005 Great Lakes region ton-miles trend (0.1% annual growth)	AEO forecasts national Domestic Shipping residual oil consumption +1.1% per year	Used historical growth rate since region-specific
NOX	2102006000	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -0.01% per year; AEO forecast = 1.4% per year	
NOX	2104008070	78.0	84.3	Extrapolation of national 1999-2004 trend in OWB sales (exponential growth) thru 2006; linear growth thru 2008; 2009+ based on rural population growth rate		
ROG	2461850000	4.8	16.1	Regional employment projections for "Pesticide Handlers, Sprayers" combined with projected solvent content change from Freedonia's "Solvents to 2010-Agricultural Chemical Market for Solvents" (-0.4% per year)		Forecast data are state-level
ROG	2461020000	-1.9	-6.0	No employment growth assumption due to contradictory historic and forecast trends in "Paving, Surfacing, & Tamping Operators" employment, combined with projected solvent content change from Freedonia's "Solvents to 2010-Asphalt Production Market for Solvents" (-0.5% per year)		Forecast data are state-level
ROG	2401200000	-6.5	-16.1	Population forecast combined with projected change in paint solvent content from Freedonia's "Solvents to 2010-Paints/Coatings Market for Solvents" (-1.9% per year)		Forecast data are county-level
ROG	2401001000	-9.9	-9.3	Regression with Population forecast as explanatory variable combined with Freedonia projected change in proportion of total Architectural coatings that are solvent-based (-2.0% per year)		Forecast data are county-level
ROG	2460100000	-3.9	-11.6	Population forecast combined with projected solvent content change from Freedonia's "Solvents to 2010-Cosmetics & Toiletries Market for Solvents" (-1.5% per year)		Forecast data are county-level
ROG	2501011010	0.2	0.3	Regression equation with Gas and Oil Expenditures as explanatory variable		Forecast data are state-level
ROG	2501060100	0.2	0.3	Regression equation with Gas and Oil Expenditures as explanatory variable		Forecast data are state-level
ROG	2460800000	-10.5	-15.6	Regression equation with Population as explanatory variable		Forecast data are county-level
ROG	2501060050	0.2	0.3	Regression equation with Gas and Oil Expenditures as explanatory variable		Forecast data are state-level
ROG	2460400000	0.1	3.3	Population forecast combined with projected change in solvent use/vehicle from Freedonia's "Solvents to 2010-Transportation Markets for Solvents" (-0.4% per year)		Forecast data are county-level
ROG	2425000000	0.0	0.0	No employment growth assumption due to contradictory historic and forecast trends for "Printing Machine Operators" employment, and no projected change in solvent content of ink from Freedonia's "Solvents to 2010-Printing Ink Market for Solvents"		
ROG	2401005000	-12.9	-38.9	Employment projections for "Automotive Body and Related Repairers" combined w/ change in proportion of automotive coatings that are solvent-based from Freedonia's "Automotive Coatings, Adhesives & Sealants-Automotive Coatings Demand by Formulation and Substrate" (-4.3% per year)		Forecast data are state-level
ROG	2460500000	-6.5	-16.1	Population forecast combined with projected change in paint solvent content from Freedonia's "Solvents to 2010-Paints/Coatings Market for Solvents" (-1.9% per year)		Forecast data are county-level

Table II-2 (continued)

Pollutant	SCC	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
ROG	2460200000	0.6	6.8	Population forecast combined with projected change in cleaning product solvent content from Freedonia's "Solvents to 2010-Cleaning Product Market for Solvents" (-0.1% per year)		Forecast data are county-level
ROG	2415020000	-15.0	-35.9	Fabricated Metals sector employment forecast combined with projected change in solvent use from Freedonia's "Solvents to 2010-Metal Processing Market for Solvents" (-3.7% per year)		Forecast data are state-level
ROG	2415025000	0.2	-11.4	Machinery and Computer Equipment sector employment forecast combined with projected change in solvent use from Freedonia's "Solvents to 2010-Metal Processing Market for Solvents" (-3.7% per year)		Forecast data are state-level
ROG	2460600000	-10.0	-24.4	Population forecast combined with projected change in solvent content from Freedonia's "Solvents to 2010-Adhesives and Sealants Market for Solvents" (-2.7% per year)		Forecast data are county-level
ROG	2420000370	-1.6	-0.4	Regional employment projections for "Laundry and Dry Cleaning Workers" (+0.7% per year) combined with projected solvent content from Freedonia's "Solvents to 2010-Dry Cleaning and Other Markets for Solvents" (-0.7%)		
ROG	2630010000	4.1	13.8	Growth rate from regional industrial wastewater flow design forecast from Drinking Water Infrastructure Needs Survey		
ROG	2501060101	0.2	0.3	Regression equation with Gas and Oil Expenditures as explanatory variable		Forecast data are state-level
ROG	2415360000	2.4	10.3	Regional employment projections for "Automotive Service Technicians and Mechanics" combined with forecast change in solvent use from "Solvents to 2010-Transportation Markets for Solvents" (-0.4% per year)		
ROG	2401002000	-9.9	-9.3	Regression with Population forecast as explanatory variable combined with Freedonia projected change in proportion of total Architectural coatings that are solvent-based (-2.0% per year)		Forecast data are state-level
ROG	2401003000	3.6	12.3	Regression equation with Population as explanatory variable		Forecast data are state-level
ROG	2104008070	78.0	84.3	Extrapolation of national 1999-2004 trend in OWB sales (exponential growth) thru 2006; linear growth thru 2008; 2009+ based on rural population growth rate		
SO2	2601020000	7.2	15.0	Commercial sector employment forecast		Forecast data are state-level
SO2	2102004000	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = +0.5% per year; AEO forecast = -0.3% per year	
SO2	2103004000	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -2.0% per year; AEO forecast = 0.8% per year	
SO2	2275020000	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.7% per year	
SO2	2102005000	-49.4	-49.6	AEO forecast for industrial sector residual oil consumption	DOE 1990-2004 = -6.6% per year; AEO forecast = -5.1% per year	
SO2	2102002000	2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	

Table II-2 (continued)

Pollutant	SCC	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
SO2	2285002006	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -1.4% per year; AEO forecast = +1.4% per year	Note that post-2001 trend is upward & historical data has several ups/downs
SO2	2104008070	78.0	84.3	Extrapolation of national 1999-2004 trend in OWB sales (exponential growth) thru 2006; linear growth thru 2008; 2009+ based on rural population growth rate		

- Animal Husbandry: projected number of animals from EPA's ammonia emission forecasts for animal husbandry operations (EPA, 2004);

- Marine Vessels Commercial, Diesel–Push Boats: historical (1998-2004) fuel consumption for barge traffic on rivers in LADCO region (ENVIRON, 2007a);

- Multiple Fuel Combustion categories: DOE East North Central region energy forecasts from *AEO 2007* and 1990-2004 LADCO region energy consumption data (DOE, 2007a and 2007b);

- Commercial Aircraft: state-level itinerant aircraft operations (FAA, 2007);

- Diesel Line Haul Locomotives–Commuter Lines: Metra diesel fuel expenditure/price projections (Metra, 2007);

- Pesticide Application–Agricultural: LADCO region projected number of "pesticide handlers, sprayers, and applicators, vegetation" (BLS, 2007);

- Commercial Asphalt Application–All Processes: LADCO region projected number of "paving, surfacing, and tamping operators" (BLS, 2007);

- Graphic Arts –All Processes: LADCO region projected number of "printing machine operators" (BLS, 2007);

- Surface Coating–Auto Refinishing: SIC 7532: LADCO region projected number of "Automotive Body and Related Repairers" (BLS, 2007);

- Dry Cleaning, All Processes–Special Naphthas: LADCO region projected number of "Laundry and Dry Cleaning Workers" (BLS, 2007);

- Wastewater Treatment-Industrial: LADCO region projected wastewater treatment industrial design flow (EPA, 2007a); and

- Degreasing–Auto Repair Services (SIC 75): Cold Cleaning: LADCO region projected number of "Automotive Service Technicians and Mechanics" (BLS, 2007).

Many of the above are solvent use categories for which Pechan also incorporated projected solvent content changes as forecast by The Freedonia Group, Inc. (Freedonia, 2006).

In cases where energy consumption is the emissions activity, a common growth factor development approach was to compare available regional historical (1990-2004) energy consumption data to *AEO 2007* forecast data to determine if the forecast growth rates appear suspect relative to historical trends. Pechan conducted similar historical/forecast activity trend comparisons for the non-fuel combustion priority categories whenever historical trend data were readily available (e.g., occupational employment data). In selecting from alternative data

sources/trend data, the general decision-making hierarchy was as follows, listed in order of preference:

1. If the forecast and historical trends were in the same direction, Pechan relied on forecast data (an exception was made, however, in cases where forecast data were only available on a national-level, but historical data were available for the LADCO region).

2. If the forecast and historical trends were in different directions (e.g., forecast trend is for an increase in activity, but historical trend was a decrease), Pechan applied a no growth assumption.

Outdoor Wood Boilers

Residential Wood Combustion from Outdoor Wood Boilers (SCC 2104008070) was not originally identified as a source category for growth indicator review because this category was only recently added to LADCO's emissions inventory. Outdoor Wood Boilers (OWBs) have become much more prevalent in the last several years as homeowners seek ways to avoid recent large increases in natural gas and home heating oil prices. This source category does not exist in EPA's official SCC list, and there is no current EPA emission inventory preparation guidance for this sector. Pechan assumed that this category's emissions are based on the estimated number of wood boilers, the average amount of wood burned in each boiler, and emission factors that are related to the amount of wood burned.

Investigations indicate little historical and forecast OWB data exist to assist in identifying future trends in LADCO region OWB use: state-specific sales from nine manufacturers obtained by EPA from nine manufacturers, and national sales data obtained by the New York Attorney General's Office via subpoena of 21 manufacturers. These sales data are for 1999-2004. Because of the much greater manufacturer coverage for the national data, and because the state estimates indicate that the majority of recent OWBs sales have occurred in the LADCO states, Pechan focused the historical trend analysis on the national data. These data indicate an extremely high average growth rate of 41 percent per year over the 1999-2004 period. Manufacturers indicate that although OWBs have been available for sale since the 1980s, the very large OWB sales growth rates are new phenomenon. The growth rates appear to mainly result from homeowner reactions to recent large increases in residential heating prices (e.g., between 1999 and 2004, residential natural gas and distillate oil prices rose 61 and 87 percent, respectively). Because DOE data indicate that natural gas accounts for the majority of residential energy consumption in the LADCO States, and increases in residential natural gas prices continued through 2006 (the average annual price for residential natural gas increased 28 percent between 2004 and 2006), Pechan forecast the national number of OWBs through 2006 via extrapolation of the 1999-2004 national OWB trend. In particular, Pechan fit an exponential equation to the 1994-2004 data, and used the equation to estimate 2005 and 2006 OWB counts.

Next, Pechan reviewed *AEO 2007* projections of residential natural gas prices for the East North Central region (which includes 5 of the 6 LADCO region States) to identify whether recent increases are expected to continue. The *AEO 2007* projects the average 2007 price for residential

natural gas in the East North Central region to be 4 percent lower than in 2006, and forecasts continued price decreases through the 2008-2018 period (see table below).

Year	Residential Natural Gas Price ($/million Btu)	% Change from 2006
2006	12.08	
2007	10.92	-4.1
2008	10.80	-5.1
2009	10.28	-9.7
2010	10.02	-11.9
2011	9.61	-15.5
2012	9.48	-16.9
2013	9.28	-18.4
2014	9.32	-18.1
2015	9.27	-18.6
2016	9.37	-17.7
2017	9.60	-15.7
2018	9.56	-20.8

Given the projected modest price decreases thru 2008, and the fact that distillate oil prices are forecast to increase 6.1 percent between 2006 and 2008, and because one expects a time lag in responding to energy price changes, Pechan assumes that OWB sales will continue to increase at a significant rate through 2008. Pechan specifically fit a linear trend line to the 1999-2004 OWB, and projected OWBs in 2007 and 2008 by extending the trend through 2008, and applying each year's growth rate to the estimated count of OWBs in 2006.

By 2009, Pechan projects that the larger projected declines in natural gas prices, and forecasted decreases in other heating fuel prices, will significantly restrain OWB growth. In addition, because of neighborhood smoke nuisance concerns, and the need for ready access to inexpensive wood, it is expected that the market for OWBs will be generally constrained to heavily-wooded rural areas. Therefore, Pechan forecasts post-2008 year OWB growth to more closely trend with population growth in these areas. To approximate this growth, Pechan compiled 1990 and 2000 total and rural area population data for the LADCO region. These data indicate that rural area population grew at approximately 60 percent of the rate of total population over this period. Pechan estimated rural area population growth for the LADCO region by multiplying this adjustment factor by the forecasted growth rate for total population in the LADCO region. The following table displays the projected count of OWBs in the LADCO region for 2005, 2009, 2002, and 2018.

Year	Estimated # of OWBs
2005	81,082
2009	144,356
2012	145,911
2018	149,421

It is important to note that it is particularly challenging to forecast OWB activity given the extremely high OWB sales growth rates that have occurred in recent years. LADCO will want to closely monitor activity and emission trends for this category given its relative importance in the emissions inventory, recent historical growth rates, and additional unique characteristics.

Finally, Pechan reviewed the complete list of area/MAR source categories in the LADCO base year inventory to identify the priority category growth indicators that could be applied to non-priority area/MAR categories. This step yielded priority category growth indicator assignments for an additional 26 area/MAR categories.

C. NON-EGU POINT SOURCES

Table II-3 displays the priority point source categories, including the description and emissions activity associated with each category. The last column in this table identifies each category's growth indicator assignment under the previous growth and control factor contract. Table II-4 presents the assigned growth indicator for each priority point source category and identifies any alternative growth indicators that were considered. Pechan first considered the use of historical throughput data from LADCO state point source inventories to identify recent trends that provided sufficient support for extrapolation. As mentioned above, for energy consumption sectors, Pechan compared regional historical (1990-2004) energy consumption data to *AEO 2007* forecast data to determine if the forecast growth rates appear suspect relative to historical trends.

In selecting from alternative growth indicator data sources, the general decision-making hierarchy was as follows, listed in order of preference:

(1) If throughput data were available for states representing a majority of emissions for a given category, and these data indicated a consistent trend, the historical throughput trend was extended thru 2009, and held constant thereafter (two reasons for not extending the trend throughput the entire forecast period are that throughput data are only available for a three or a six-year period, and in some cases the historical throughput decrease was so large that it would eventually result in no activity);

(2) If the forecast and historical trends were in the same direction, Pechan relied on the forecast data (an exception was made, however, if the forecast data were only available on a national-level, but the historical data were available for the LADCO region); and

If the forecast and historical trends were in different directions (e.g., forecast trend is for an increase in activity, but historical trend was a decrease), Pechan applied a no growth assumption.

Table II-3. Priority Emission Activity Point Source Categories

POLLUTANT	SCC	DESC2	DESC3	DESC4	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
NH3	10200601	Industrial	Natural Gas	> 100 Million Btu/hr	Volume of natural gas burned in industrial pt source boilers of >100 MMBtu	No growth based on historical (1990-2001) energy data
NH3	30102599	Chemical Manufacturing	Cellulosic Fiber Production	Other Not Classified	Amount of cellulosic fiber produced	Avg of REMI employment & output GFs for Plastics, Materials, & Synthetics sector
NH3	10200602	Industrial	Natural Gas	10-100 Million Btu/hr	Volume of natural gas burned in industrial pt source boilers of 10-100 MMBtu	No growth based on historical energy data
NH3	30199999	Chemical Manufacturing	Other Not Classified	Specify in Comments Field	Amount of (unknown) chemical products produced	Avg of REMI employment & output GFs for Chemicals sector
NH3	10200204	Industrial	Bituminous/Subbituminous Coal	Spreader Stoker	Amount of bituminous coal burned in spreader stoker industrial pt source boilers	AEO Industrial steam coal
NOX	20200202	Industrial	Natural Gas	Reciprocating	Volume of natural gas burned in industrial pt source reciprocating engines	No growth based on historical energy data
NOX	30500606	Mineral Products	Cement Manufacturing (Dry Process)	Kilns	Amount of cement produced via dry process	LADCO region historical cement production growth rate
NOX	30600201	Petroleum Industry	Catalytic Cracking Units	Fluid Catalytic Cracking Unit	Amount of fresh feed processed via fluid catalytic cracking units (FCCU)	AEO Refined Petroleum Products Supplied (national)
NOX	30600104	Petroleum Industry	Process Heaters	Gas-fired	Volume of gas burned in petroleum industry pt source process heaters	AEO Refining sector natural gas (national)
NOX	10200202	Industrial	Bituminous/Subbituminous Coal	Pulverized Coal: Dry Bottom	Amount of bituminous coal burned in dry bottom industrial pt source boilers	AEO Industrial steam coal
NOX	10200601	Industrial	Natural Gas	> 100 Million Btu/hr	Volume of natural gas burned in industrial pt source boilers of >100 MMBtu	No growth based on historical energy data
NOX	30300304	Primary Metal Production	By-product Coke Manufacturing	Quenching	Amount of coal charged to manufacture coke	REMI output for Blast Furnaces and Basic Steel products sector
NOX	10200217	Industrial	Bituminous/Subbituminous Coal	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous	Amount of bituminous coal burned in bubbling bed industrial pt source boilers	AEO Industrial steam coal
NOX	10200707	Industrial	Process Gas	Coke Oven Gas	Volume of process gas burned in coke ovens	AEO Metallurgical coal consumption projections (national)
NOX	10200602	Industrial	Natural Gas	10-100 Million Btu/hr	Volume of natural gas burned in industrial pt source boilers of 10-100 MMBtu	No growth based on historical energy data

Table II-3 (continued)

POLLUTANT	SCC	DESC2	DESC3	DESC4	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
NOX	20200254	Industrial	Natural Gas	4-cycle Lean Burn	Volume of natural gas burned in industrial sector 4-cycle lean burn IC engines	No growth based on historical energy data
NOX	20100102	Electric Generation	Distillate Oil (Diesel)	Reciprocating	Amount of distillate oil burned in reciprocating engines for electricity	AEO Electric Generation distillate oil
NOX	20200201	Industrial	Natural Gas	Turbine	Volume of natural gas burned in industrial sector turbines	No growth based on historical energy data
NOX	39000689	In-process Fuel Use	Natural Gas	General	Volume of industrial process pt source natural gas burned	No growth based on historical energy data
NOX	10200201	Industrial	Bituminous/Subbituminous Coal	Pulverized Coal: Wet Bottom	Amount of bituminous coal burned in wet bottom industrial pt source boilers	AEO Industrial steam coal
NOX	10200701	Industrial	Process Gas	Petroleum Refinery Gas	Volume of petroleum refinery (still) gas burned	No growth based on historical energy data
ROG	30100399	Chemical Manufacturing	Ammonia Production	Other Not Classified	Amount of ammonia produced	REMI output for Agricultural Chemicals sector
ROG	30201916	Food and Agriculture	Vegetable Oil Processing	Oil Extraction	Amount of extractor feed cake produced	REMI output for Grain Mill Products and Fats and Oils sector
ROG	40500511	Printing/Publishing	General	Gravure: 2754	Amount of solvent in ink used by pt sources	REMI output for Commercial Printing and Business Forms sector
ROG	30199999	Chemical Manufacturing	Other Not Classified	Specify in Comments Field	Amount of (unknown) chemical products produced	Avg of REMI employment & output GFs for Chemicals sector
ROG	30125099	Chemical Manufacturing	Methanol/Alcohol Production	Other Not Classified	Amount of methanol/alcohol produced	REMI output for Industrial Chemicals sector
ROG	40201301	Surface Coating Operations	Paper Coating	Coating Operation	Amount of solvent in coating used by pt sources	No growth based on historical LADCO emissions trend
ROG	40200101	Surface Coating Operations	Surface Coating Application - General	Paint: Solvent-base	Amount of coating mix applied by pt sources	No growth based on historical LADCO emissions trend
ROG	30102599	Chemical Manufacturing	Cellulosic Fiber Production	Other Not Classified	Amount of cellulosic fiber produced	Avg of REMI employment & output GFs for Plastics, Materials, & Synthetics sector
ROG	30500201	Mineral Products	Asphalt Concrete	Rotary Dryer: Conventional Plant (see 3-05-002-50 to -53 for	Amount of hot mix asphalt produced by pt sources	Avg of REMI employment & output GFs for Misc. Petroleum and Coal Products sector
ROG	30201906	Food and Agriculture	Vegetable Oil Processing	Corn Oil: General	Amount of extractor feed cake produced	REMI output for Grain Mill Products and Fats and Oils sector
ROG	30201919	Food and Agriculture	Vegetable Oil Processing	Fugitive Leaks	Amount of extractor feed cake produced	REMI output for Grain Mill Products and Fats and Oils sector
ROG	40200110	Surface Coating Operations	Surface Coating Application - General	Paint: Solvent-base	Amount of solvent-based coatings applied by pt sources	Historical LADCO throughput data trend
ROG	40201899	Surface Coating Operations	Metal Coil Coating	Other Not Classified	Amount of solvent in coating used by pt sources	REMI output for Nonferrous Rolling and Drawing sector
ROG	40388801	Petroleum Product Storage at Refineries	Fugitive Emissions	Specify in Comments Field	Petroleum product storage capacity at refineries	AEO Refined Petroleum Products Supplied (national)
ROG	40200701	Surface Coating Operations	Surface Coating Application - General	Adhesive Application	Amount of adhesive coatings applied by pt sources	REMI output for Total Manufacturing sector

Table II-3 (continued)

POLLUTANT	SCC	DESC2	DESC3	DESC4	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
SO2	30600201	Petroleum Industry	Catalytic Cracking Units	Fluid Catalytic Cracking Unit	Amount of fresh feed processed via FCCU	AEO Refined Petroleum Products Supplied (national)
SO2	10200202	Industrial	Bituminous/Subbituminous Coal	Pulverized Coal: Dry Bottom	Amount of bituminous coal burned in dry bottom industrial pt source boilers	AEO Industrial steam coal
SO2	30600805	Petroleum Industry	Fugitive Emissions	Miscellaneous: Sampling/Non-Asphalt Blowing/Purging/etc.	Barrels of refinery feed processed	AEO Refined Petroleum Products Supplied (national)
SO2	30199999	Chemical Manufacturing	Other Not Classified	Specify in Comments Field	Amount of (unknown) chemical products produced	Avg of REMI employment & output GFs for Chemicals sector
SO2	10200217	Industrial	Bituminous/Subbituminous Coal	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous	Amount of bituminous coal burned in bubbling bed industrial pt source boilers	AEO Industrial steam coal
SO2	10200201	Industrial	Bituminous/Subbituminous Coal	Pulverized Coal: Wet Bottom	Amount of bituminous coal burned in wet bottom industrial pt source boilers	AEO Industrial steam coal
SO2	10200225	Industrial	Bituminous/Subbituminous Coal	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	Amount of subbituminous coal burned in overfeed stoker industrial pt source boilers	AEO Industrial steam coal
SO2	30500606	Mineral Products	Cement Manufacturing (Dry Process)	Kilns	Amount of cement produced via dry process	LADCO region historical cement production growth
SO2	30600401	Petroleum Industry	Blowdown Systems	Blowdown System with Vapor Recovery System with Flaring	Barrels of refinery feed processed	AEO Refined Petroleum Products Supplied (national)
SO2	10200204	Industrial	Bituminous/Subbituminous Coal	Spreader Stoker	Amount of bituminous coal burned in spreader stoker industrial pt source boilers	AEO Industrial steam coal
SO2	10300217	Commercial/Institutional	Bituminous/Subbituminous Coal	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bitumin.)	Amount of bituminous coal burned in bubbling bed commercial pt source boilers	AEO Commercial coal
SO2	39000701	In-process Fuel Use	Process Gas	Coke Oven or Blast Furnace	Volume of coke oven or blast furnace gas burned	AEO Metallurgical coal consumption projections (national)
SO2	30103201	Chemical Manufacturing	Elemental Sulfur Production	Mod. Claus: 2 Stage w/o Control (92-95% Removal)	Amount of 100% sulfur produced	REMI output for Industrial Chemicals sector
SO2	10300225	Commercial/Institutional	Bituminous/Subbituminous Coal	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	Amount of subbituminous coal burned in overfeed stoker commercial pt source boilers	AEO Commercial coal
SO2	10300209	Commercial/Institutional	Bituminous/Subbituminous Coal	Spreader Stoker (Bituminous Coal)	Amount of bituminous coal burned in spreader stoker commercial pt source boilers	AEO Commercial coal
SO2	10200401	Industrial	Residual Oil	Grade 6 Oil	Amount of residual oil (No. 6) burned in industrial pt source boilers	No growth based on historical energy data

Table II-3 (continued)

POLLUTANT	SCC	DESC2	DESC3	DESC4	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
EMISSION TREND ANALYSIS CATEGORIES NOT LISTED ABOVE WITH CONSISTENT THROUGHPUT TRENDS						
VOC	40202201	Petroleum and Solvent Evaporation	Surface Coating Operations	Plastic Parts: Coating Operation	Amount of solvent used in coating applied	Historical LADCO throughput data trend
NOX	39000699	In Process Fuel Use	Natural Gas	General	Amount of nat gas used in industrial processes	No growth based on historical energy data

Table II-4. Growth Indicators for Priority Point Source Categories

Pollutant	SCC	Emissions Priority Category	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
NH3	10200601	NOx	-11.5	-11.5	Historic throughput trend from 3 states (-3.0% per year) extended thru 2009; post-2009 held constant.	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	
NH3	30102599		4.9	18.2	Avg of REMI employment & output growth factors for Plastics, Materials, & Synthetics sector		Forecast data are state-level
NH3	10200602	NOx	-12.2	-12.2	Historic throughput trend from 4 states (-3.2% per year) extended thru 2009; post-2009 held constant.	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	
NH3	30199999		8.9	25.6	Avg of REMI employment & output growth factors for Chemicals sector		Forecast data are state-level
NH3	10200204	NOx	2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	Did not use throughput since available states represent <50% of regional emissions
NOX	20200202	NOx	0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	Did not use throughput since available state represent <50% of regional emissions
NOX	30500606		8.2	29.4	LADCO region historical cement production growth rate (+2.0% per year)		
NOX	30600201	SO2	0.4	0.4	AEO refinery distillation projections for Petroleum Administration District (PAD) II, which includes all LADCO states plus additional surrounding states	Similar 1990-2005 data also includes states not in LADCO region and shows very small growth rate	Did not use throughput since available states represent <50% of regional emissions
NOX	30600104		5.9	20.6	1991-2002 Midwest Census region Refining sector natural gas consumption growth rate (+1.5% per year)	AEO National Refining sector natural gas consumption forecast is +2.7% per year	Used historical growth rate because it is regional and of similar direction to AEO national forecast
NOX	10200202	NOx	2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	Did not use throughput since available states represent <50% of regional emissions
NOX	10200601	NOx	-11.5	-11.5	Historic throughput trend from 3 states (-3.0% per year) extended thru 2009; post-2009 held constant.	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	
NOX	30300304		-6.2	-19.8	AEO forecast for metallurgical coal consumption	DOE 1990-2004 = -3.0% per year; AEO forecast = -1.7% per year	
NOX	10200217		2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	
NOX	10200707		-6.2	-19.8	AEO forecast for metallurgical coal consumption	DOE 1990-2004 = -3.0% per year; AEO forecast = -1.7% per year	
NOX	10200602	NOx	-12.2	-12.2	Historic throughput trend from 4 states (-3.2% per year) extended thru 2009; post-2009 held constant.	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	
NOX	20200254		0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	

Table II-4 (continued)

Pollutant	SCC	Emissions Priority Category	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
NOX	20100102		1.7	5.5	DOE 1990-2004 historic trend (+0.4%)	AEO forecast = +5.0% per year thru 2009, but near equivalent decrease from 2009 to 2018	Used historic trend because of large difference between 2009 and 2018 forecast, & historic growth rate is in between the 2 forecast values
NOX	20200201		0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	
NOX	39000689		0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -0.01% per year; AEO forecast = +1.4% per year	
NOX	10200201	SO2	2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	No throughput data available
NOX	10200701		-1.3	-4.1	DOE 1990-2004 historic trend (-0.3% per year)	AEO forecast = 2009 (-1.0% per year) and 2018 (-0.1% per year)	Used historic trend because is region-specific (forecast is national), and historic change is in between the 2009 & 2018 AEO growth rates
ROG	30100399		-19.7	-28.6	Freedonia's "Chemical Catalysts to 2009-Ammonia Catalyst Demand" - national projections adjusted for relative state growth in REMI output for Agricultural Chemicals sector		Forecast data are state-level
ROG	30201916		2.2	11.9	Avg of REMI employment & output growth factors for Grain Mill Products and Fats and Oils sector		Forecast data are state-level
ROG	40500511		0.0	0.0	No growth due to contradictory historic trend versus forecast trend in regional employment for "Printing Machine Operators"		Freedonia's "Solvents to 2010-Printing Ink Market for Solvents" indicates no projected change in solvent content of ink
ROG	30199999		8.9	25.6	Avg of REMI employment & output growth factors for Chemicals sector		Forecast data are state-level
ROG	30125099		1.1	5.3	Freedonia's "Chemical Catalysts to 2009-Alcohols Catalyst Demand by Application" - national projections adjusted for relative state growth in REMI output for Industrial Chemicals sector		Forecast data are state-level
ROG	40201301		0	0	No growth based on consistent historic LADCO emissions trend		2005 emissions data confirm previous no growth approach
ROG	40200101	VOC	-6.4	-21.4	Regional employment projections for "Coating, Painting, and Spraying Machine Operators, and Tenders" adjusted for solvent content of paints and coatings from Freedonia's "Solvents to 2010-Paints and Coatings Market for Solvents" (-1.9% per year)		Forecast data are state-level; adopted approach believed better than available historic throughput data

Table II-4 (continued)

Pollutant	SCC	Emissions Priority Category	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
ROG	30102599		4.9	18.2	Avg of REMI employment & output growth factors for Plastics, Materials, & Synthetics sector		Forecast data are state-level
ROG	30500201		8.3	21.5	Avg of REMI employment & output growth factors for Misc. Petroleum and Coal Products sector		Forecast data are state-level
ROG	30201906		2.2	11.9	Avg of REMI employment & output growth factors for Grain Mill Products and Fats and Oils sector		Forecast data are state-level
ROG	30201919		2.2	11.9	Avg of REMI employment & output growth factors for Grain Mill Products and Fats and Oils sector		Forecast data are state-level
ROG	40200110	VOC	-6.4	-21.4	Regional employment projections for "Coating, Painting, and Spraying Machine Operators, and Tenders" adjusted for solvent content of paints and coatings from Freedonia's "Solvents to 2010-Paints and Coatings Market for Solvents" (-1.9% per year)		Forecast data are state-level; adopted approach believed better than available historic throughput data
ROG	40201899		6.9	26.0	Freedonia's "Protective Coatings to 2009-Demand for Coil Coatings" - national projections adjusted for relative state growth in REMI output for Nonferrous Rolling and Drawing sector, adjusted for projected solvent content information for paints and coatings from "Solvents to 2010-Paints/Coatings Market for Solvents" (-1.9% per year)		Forecast data are state-level; coil coating has seen significant growth historically, and such growth is projected to continue in the future
ROG	40388801		0.4	0.4	AEO refinery distillation projections for Petroleum Administration District (PAD) II, which includes all LADCO states plus additional surrounding states	1990-2005 data also includes states not in LADCO region and shows similar very small growth rate	
ROG	40200701		-1.6	-1.0	Freedonia's "Solvents to 2010-Adhesives & Sealants Market for Solvents" national projections, adjusted for relative state growth in REMI output in Total Manufacturing sector		
SO2	30600201	SO2	0.4	0.4	AEO refinery distillation projections for Petroleum Administration District (PAD) II, which includes all LADCO states plus additional surrounding states	1990-2005 data also includes states not in LADCO region and shows similar very small growth rate	Did not use throughput since available state represent <50% of regional emissions
SO2	10200202	NOx	2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	No throughput data available
SO2	30600805	SO2	0.4	0.4	AEO refinery distillation projections for Petroleum Administration District (PAD) II, which includes all LADCO states plus additional surrounding states	1990-2005 data also includes states not in LADCO region and shows similar very small growth rate	No throughput data available
SO2	30199999		8.9	25.6	Avg of REMI employment & output GFs for Chemicals sector		Forecast data are state-level
SO2	10200217		2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	
SO2	10200201	SO2	2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	No throughput data available
SO2	10200225		2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	
SO2	30500606		8.2	29.4	LADCO region historical cement production growth rate (+2.0% per year)		

Table II-4 (continued)

Pollutant	SCC	Emissions Priority Category	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
SO2	30600401		0.4	0.4	AEO refinery distillation projections for Petroleum Administration District (PAD) II, which includes all LADCO states plus additional surrounding states	1990-2005 data also includes states not in LADCO region and shows similar very small growth rate	
SO2	10200204	NOx	2.9	-0.6	AEO forecast for other industrial coal combustion	DOE 1990-2004 = -1.5% per year; AEO forecast = <-0.1% per year	Did not use throughput since available states represent <50% of regional emissions
SO2	10300217		0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -1.2% per year; AEO forecast = +0.0% per year	
SO2	39000701		-6.2	-19.8	AEO forecast for metallurgical coal consumption	DOE 1990-2004 = -3.0% per year; AEO forecast = -1.7% per year	
SO2	30103201		2.5	8.2	1996-2005 recovered elemental sulfur production growth rate (+0.6% per year) for IL + MI + MN + OH		
SO2	10300225		0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -1.2% per year; AEO forecast = +0.0% per year	
SO2	10300209		0.0	0.0	No growth due to contradictory historic and forecast trends	DOE 1990-2004 = -1.2% per year; AEO forecast = +0.0% per year	
SO2	10200401	SO2	-49.4	-49.6	AEO forecast for industrial residual oil consumption (-5.1% per year)	DOE 1990-2004 = -6.6% per year	Used AEO forecast due to similarity with AEO historical trend and throughput trend (-6.1%)
NON-PRIORITY CATEGORIES INCLUDED IN EMISSION TREND ANALYSIS WITH CONSISTENT THROUGHPUT TRENDS:							
VOC	40202201	VOC	-33.5	-33.5	Historic throughput trend from 3 states (-9.7%) extended thru 2009; post-2009 held constant.		
NOX	39000699	NOx	-15.8	-15.8	Historic throughput trend from 3 states (-4.2%) extended thru 2009; post-2009 held constant.		

Table II-4 also presents the 2005-2009 and 2005-2018 growth rates for the final assigned point source growth indicators. In addition, Pechan reviewed the complete list of point SCCs in the LADCO base year inventory to identify the priority category growth indicators that could be applied to non-priority point source categories. This step yielded priority category growth indicator assignments for an additional 539 point source categories.

D. NONROAD MODEL SOURCES

At LADCO's request, Pechan analyzed potential improvements to the default growth indicators for the 25 NONROAD model priority source categories displayed in Table II-5. With the exception of the all-terrain vehicle, offroad motorcycle, and snowmobile categories, 1989-1996 national equipment population trends form the basis for the NONROAD growth rates. For these other three categories, NONROAD relies on national equipment population forecasts prepared by a relevant trade association (see Table II-5 for details).

Table II-6 reports this study's growth indicator assignments for priority NONROAD model source categories. Given the acknowledged shortcomings of the NONROAD growth rates (use of 1989-1996 national equipment populations to project future equipment populations in each region of the country), the growth factor improvements generally reflect the use of regional/state-level forecast data that are expected to correlate with use of the equipment (i.e., regional occupational employment projections, state-level economic sector employment forecasts, or state-level landing/take-off projections). Table II-6 also displays any alternative growth indicators that were considered. For the three categories for which NONROAD relies on forecasts rather than historical 1989-1996 trends, Pechan compiled available recent historical equipment population estimates. This information was used to revise the current national forecast approach to reflect more recent information, and whenever possible, recent LADCO region-specific equipment population trends.

Although the NONROAD model growth rates are fuel-specific, Pechan was unable to develop fuel-specific forecast data. Therefore, Pechan updated a priority category's growth rates only when the 1989-1996 national equipment populations indicated that the category's fuel-specific growth rate had traditionally been similar to the overall sector's equipment population growth rate. Table II-6 identifies instances where the past fuel-specific growth rate substantially differed from the overall sector's growth rate. In these cases, Pechan retained the NONROAD model fuel-specific forecast approach. Section IV.A. describes how Pechan incorporated the updated equipment population growth rates into the NONROAD model

Table II-5. Priority Emission Activity NONROAD Model Source Categories

SCC	DESCRIPTION SUMMARY	EMISSIONS ACTIVITY	CURRENT GROWTH BASIS
2260001030	2-Stroke ATV	Population of 2-stroke gasoline ATVs	NONROAD (Motorcycle Industry Council national 2-stroke gasoline ATV projections)
2265001030	4-Stroke ATV	Population of 4-stroke gasoline ATVs	NONROAD (Motorcycle Industry Council national 4-stroke gasoline ATV projections)
2260001010	2-Stroke Offroad Motorcycles	Population of 2-stroke gasoline offroad motorcycles	NONROAD (Motorcycle Industry Council national off-highway motorcycle population projections)
2265001010	4-Stroke Offroad Motorcycles	Population of 4-stroke gasoline offroad motorcycles	NONROAD (Motorcycle Industry Council national off-highway motorcycle population projections)
2267006000	LPG Light Commercial	Population of light commercial LPG-fueled equipment	NONROAD (national 1989-1996 LPG light commercial equipment population growth rate)
2270004000	Diesel Lawn & Garden Equipment	Population of lawn & garden diesel-fueled equipment	NONROAD (national 1989-1996 diesel lawn & garden equipment population growth rate)
2270008000	Diesel Airport Service Equipment	Population of airport service diesel-fueled equipment	NONROAD (national 1989-1996 diesel airport service equipment population growth rate)
2267008000	LPG Airport Service Equipment	Population of airport service LPG-fueled equipment	NONROAD (national 1989-1996 total airport service equipment population growth rate)
2268008000	CNG Airport Service Equipment	Population of airport service CNG-fueled equipment	NONROAD (national 1989-1996 total airport service equipment population growth rate)
2260001020	2-Stroke Snowmobiles	Population of 2-stroke gasoline snowmobiles	NONROAD national growth (see below) with state adjustment based on real disposable income forecasts
2265001020	4-Stroke Snowmobiles	Population of 4-stroke gasoline snowmobiles	NONROAD (International Snowmobile Manufacturers Association national snowmobile population projections)
2260007000	2-Stroke Logging Equipment	Population of logging 2-stroke gasoline equipment	NONROAD (national 1989-1996 gasoline logging equipment population growth rate)
2265007000	4-Stroke Logging Equipment	Population of logging 4-stroke gasoline equipment	NONROAD (national 1989-1996 gasoline logging equipment population growth rate)
2270006000	Diesel Light Commercial	Population of light commercial diesel-fueled equipment	NONROAD (national 1989-1996 diesel light commercial equipment population growth rate)
2268006000	CNG Light Commercial	Population of light commercial CNG-fueled equipment	NONROAD (national 1989-1996 CNG light commercial equipment population growth rate)
2267007000	LPG Logging Equipment	Population of logging LPG-fueled equipment	NONROAD (national 1989-1996 logging equipment population growth rate)
2268007000	CNG Logging Equipment	Population of logging CNG-fueled equipment	NONROAD (national 1989-1996 logging equipment population growth rate)
2285002000	Diesel Railway Maintenance	Population of railway maintenance diesel-fueled equipment	NONROAD (national 1989-1996 diesel railway maintenance equipment population growth rate)
2260006000	2-Stroke Light Commercial	Population of light commercial 2-stroke gasoline equipment	NONROAD (national 1989-1996 gasoline light commercial equipment population growth rate)
2265006000	4-Stroke Light Commercial	Population of light commercial 4-stroke gasoline equipment	NONROAD (national 1989-1996 gasoline light commercial equipment population growth rate)
2270002000	Diesel Construction Equipment	Population of construction diesel-fueled equipment	NONROAD national growth with state adjustment based on Construction employment forecasts
2270003000	Diesel Industrial Equipment	Population of industrial diesel-fueled equipment	NONROAD (national 1989-1996 diesel industrial equipment population growth rate)
2267003000	LPG Industrial Equipment	Population of industrial LPG-fueled equipment	NONROAD (national 1989-1996 LPG industrial equipment population growth rate)
2270001000	Diesel Recreational Vehicles	Population of diesel recreational vehicles	NONROAD (national 1989-1996 diesel recreational equipment population growth rate)
2282020000	Diesel Recreational Marine	Population of diesel recreational marine vessels	NONROAD (national 1989-1996 diesel recreational equipment population growth rate)

Table II-6. Growth Indicators for Priority NONROAD Model Source Categories

SCC	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
2260001030	10.8	39.7	50% higher growth rate than overall LADCO region "Recreational Vehicle Service Technicians" employment projections, which is 1.7%/yr, based on premise that ATV market is less mature than market for other recreation vehicles	Available ATV/OHV registration data for MI+MN+WI indicate avg. annual growth of 14.6% between 2000 and 2005; however, 2006 data for each state is only +1 or +1.1%; NONROAD shows 2005-2006 = +10.5%. National ATV sales (not population) of +3.8% per year for 2000-2005; 2005-2006 sales = -4.2%	Did not use long-term historical trend as ATV market appears to be maturing based on most recent data (this is predicted by NONROAD model, but not until post-2010; NONROAD shows 2010-2018 = +2.7%/yr)
2265001030	10.8	39.7	50% higher growth rate than overall LADCO region "Recreational Vehicle Service Technicians" employment projections, which is 1.7%/yr, based on premise that ATV market is less mature than market for other recreation vehicles	Available ATV/OHV registration data for MI+MN+WI indicate avg. annual growth of 14.6% between 2000 and 2005; however, 2006 data for each state is only +1 or +1.1%; NONROAD shows 2005-2006 = +10.5%. National ATV sales (not population) of +3.8% per year for 2000-2005; 2005-2006 sales = -4.2%	Did not use long-term historical trend as ATV market appears to be maturing based on most recent data (this is predicted by NONROAD model, but not until post-2010; NONROAD shows 2010-2018 = +2.7%/yr)
2260001010	5.1	17.7	LADCO region employment projections for "Motorcycle Mechanics"	Unable to compile regional registration trends; national off-road motorcycle sales for 2000-2006 = +2.3%, but 2001-2006 = -1.6%	Employment projections are LADCO region-specific and fall in-between recent national sales trends
2265001010	5.1	17.7	LADCO region employment projections for "Motorcycle Mechanics"	Unable to compile regional registration trends; national off-road motorcycle sales for 2000-2006 = +2.3%, but 2001-2006 = -1.6%	Employment projections are LADCO region-specific and fall in-between recent national sales trends
2267006000	19.8	57.5	NONROAD (national 1989-1996 LPG light commercial equipment population growth rate)	REMI Commercial sector employment forecast for LADCO region (2005-2009=+1.8%yr; 2005-2018 = +1.1%/yr)	Did not use alternative because historical period indicates substantially different growth rate for LPG than overall sector
2270004000	5.8	20.1	LADCO region employment projections for "Landscaping and Groundskeeping Workers"		
2270008000	-0.7	18.0	State-level FAA itinerant air carrier + air taxi landing and take-off (LTO) forecast (updated as of December 2006)		
2267008000	-0.7	18.0	State-level FAA itinerant air carrier + air taxi landing and take-off (LTO) forecast (updated as of December 2006)		
2268008000	-0.7	18.0	State-level FAA itinerant air carrier + air taxi landing and take-off (LTO) forecast (updated as of December 2006)		
2260001020	3.5	11.9	50% lower growth rate than overall LADCO region "Recreational Vehicle Service Technicians" employment projections, which is 1.7%/yr, based on premise that snowmobile market is more mature than market for other recreation vehicles	Annual growth in snowmobile registrations for states representing 92% of 2006 LADCO region registrations: 2000-2006 = +0.0%	No growth assumption not adopted because lack of snowfall often cited as major contributing factor for recent stagnation in snowmobile registrations
2265001020	3.5	11.9	50% lower growth rate than overall LADCO region "Recreational Vehicle Service Technicians" employment projections, which is 1.7%/yr, based on premise that snowmobile market is more mature than market for other recreation vehicles	Annual growth in snowmobile registrations for states representing 92% of 2006 LADCO region registrations: 2000-2006 = +0.0%	No growth assumption not adopted because lack of snowfall often cited as major contributing factor for recent stagnation in snowmobile registrations

Table II-6 (continued)

SCC	Total % Change 2005-2009	Total % Change 2005-2018	Growth Indicator Basis	Alternatives Considered	Comment
2260007000	2.2	7.3			
2265007000	2.2	7.3	LADCO region employment projections for "Logging Equipment Operators"		
2270006000	7.2	15.0	REMI Commercial sector employment forecast for LADCO region		
2268006000	7.2	15.0	REMI Commercial sector employment forecast for LADCO region		
2267007000	2.2	7.3	LADCO region employment projections for "Logging Equipment Operators"		
2268007000	2.2	7.3	LADCO region employment projections for "Logging Equipment Operators"		
2285002000	12.2	36.7	NONROAD (national 1989-1996 diesel railway maintenance equipment population growth rate)	LADCO region employment projections for "Rail-Track Laying & Maintenance Equipment Operators" (-1.6%/yr)	Did not use alternative because historical period indicates substantially different growth rate for diesel than overall sector
2260006000	7.2	15.0	REMI Commercial sector employment forecast for LADCO region		
2265006000	7.2	15.0	REMI Commercial sector employment forecast for LADCO region		
2270002000	4.7	16.2	LADCO region employment projections for "Operating Engineers and Other Construction Equipment Operators"		
2270003000	0.1	0.2	LADCO region employment projections for "Industrial Machinery Mechanics"		
2267003000	0.1	0.2	LADCO region employment projections for "Industrial Machinery Mechanics"		
2270001000	10.4	31.5	NONROAD (national 1989-1996 diesel recreational equipment population growth rate)	LADCO region employment projections for "Recreational Vehicle Service Technicians" (+1.7%/yr)	Did not use alternative because historical period indicates substantially different growth rate for diesel than overall sector
2282020000	10.4	31.5	NONROAD (national 1989-1996 diesel recreational equipment population growth rate)	Two options: 1996-2005 LADCO region recreational boat registration growth rate (0.8%/yr) and LADCO region employment projections (+1.5%/yr) for "Motorboat Mechanics"	Did not use alternatives because historical period indicates substantially different growth rate for diesel than overall sector.

SECTION III. UPDATED EMISSION CONTROL DATA

A. NON-EGU POINT SOURCE CONTROLS

1. NO_x SIP Call

All states in the LADCO region affected by the NO_x (oxides of nitrogen) SIP (State Implementation Plan) Call requirements (OH, IN, IL, MI) indicated that their sources were complying in 2005. The only exception to this is for reciprocating internal combustion engines (RICE) in Illinois. The State of Illinois recommended that an 82 percent NO_x control efficiency be applied to large RICE engines that are affected by the SIP Call. The RICE engine requirement in Illinois has a January 1, 2008 compliance date. Table III-1 lists these engines and the associated NO_x control efficiencies applied in the emission projections. This requirement is expected to affect NO_x emissions in all projection years.

2. MACT Standards

Table III-2 summarizes the control factors used to estimate the post-2005 effects of MACT emission standards on volatile organic compounds (VOC), NO_x, and PM emissions in the projection years. The information in this table was developed from EPA guidance on estimating the criteria pollutant emission benefits of MACT standards (Page, 2007). Any post-2005 MACT standards that have no expected criteria pollutant emission reductions according to the draft EPA guidance were not included in Table III-2. Table III-2 was circulated to the states for review, and Wisconsin provided its own estimates of the expected VOC and PM emission reductions from these MACT standards in its state. The State of Michigan concurred with the emission reduction estimates made by Wisconsin. Those VOC and PM emission reduction percentages are shown in the two right-most columns of Table III-2. So, the control factor file reflects the EPA estimated values for IL, IN, MN, and OH, and the Wisconsin-provided estimates for MI and WI.

3. Consent Decrees

Previous Pechan-developed control efficiencies by source (Pechan, 2005) and pollutant were merged with the LADCO state 2005 point source file and control factors assigned accordingly. The 2005 point source control efficiencies (CEs) for sulfur dioxide (SO_2) and NO_x for fluid catalytic cracking units (FCCUs) and heaters and boilers were checked to see whether there is any compliance by 2005. Pechan also added all MACTEC revisions/additions from their earlier report to the control factor file (MACTEC incorporated cases and settlements control factors for refineries that were not evaluated for the 812 study) and made any changes/additions that were provided by the state air pollution control agencies. Table III-3 lists all of the LADCO state Non-EGU Point Sources affected by consent decrees. These sources all have post-2005 control factors applied in the analysis. There are two refineries in the study area who had either complied with their consent decrees or curtailed applicable operations by 2005, so no future year control factors were applied in this analysis. These two refineries are Premcor Refining in IL and the Flint Hills Refinery in MN.

Table III-1. RICE Engines in Illinois Affected by NO_x SIP Call

Id Number	Device	Process	Device Description	Pollutant	% Reduction	Comments
027807AAC	0003	01	ENGINES 09-ENG AND 10-ENG	NOX	59	50/50 for 2 engines = .5+.5(.18) = 59% reduction
041804AAC	0009	01	ENGINE 1213	NOX	82	
041804AAC	0010	01	ENGINE 1214	NOX	82	
041804AAC	0011	01	ENGINE 1215	NOX	82	
041804AAC	0012	01	ENGINE 1216	NOX	82	
041804AAC	0013	01	ENGINE 1217	NOX	82	
073816AAA	0001	01	WORTHINGTON MLV-10 COMPRESSOR & GAS FIRED ENGINE #12	NOX	82	
073816AAA	0004	01	CLARK TCV-10 COMPRESSOR & GAS FIRED ENGINE ENGINE #9	NOX	82	
073816AAA	0012	01	WORTHINGTON MLV-10 COMPRESSOR AND GAS FIRED ENGINE NO. 13	NOX	82	
073816AAA	0013	01	WORTHINGTON MLV-10 COMPRESSOR AND GAS FIRED ENGINE NO. 14	NOX	82	
073816AAA	0014	01	WORTHINGTON MLV-10 COMPRESSOR AND GAS FIRED ENGINE NO. 15	NOX	82	
073816AAA	0015	01	WORTHINGTON MLV-14 ENGINE #10	NOX	82	
085809AAA	0010	01	3 CLARK COMPRESSORS	NOX	82	
093802AAF	0003	01	ENGINE E-1008	NOX	82	
113817AAA	0002	01	ENGINE EC21	NOX	82	
113817AAA	0003	01	ENGINE IC11	NOX	82	
113821AAA	0002	01	ENTERPRISE RECIP COMP EC-21 4000 MP EF 3.3.2-1	NOX	82	
113821AAA	0005	01	COOPER COMPRESSOR CC22 EF 3.3.2-1 4000 HP	NOX	82	
149820AAB	0002	01	2 RECIPROCATING ENGINES (1013 - 1014)	NOX	59	50/50 for 2 engines = .5+.5(.18) = 59% reduction
149820AAB	0003	01	3 RECIPROCATING ENGINES (1015 - 1017)	NOX	82	
167801AAA	0001	01	ENGINES 1116 AND 1117	NOX	82	
167801AAA	0003	01	1-COOPER RECIPROCATING ENGINE, 4000HP, 1115	NOX	82	
167801AAA	0008	01	ENGINES 1118 AND 1119	NOX	59	50/50 for 2 engines = .5+.5(.18) = 59% reduction

Table III-2. Post-2005 MACT Standards and Expected VOC, NO_x, and PM Reductions

MACT Standard – Source Category	Code of Federal Regulations Subpart	Compliance Date (existing sources)	VOC (% Reduction)	NO_x (% Reduction)	Total PM (% Reduction)	Affected SCCs	MACT Code	Wisconsin and Michigan Values	
								VOC	PM
Asphalt Processing and Asphalt Roofing Manufacture	LLLLL	5/1/2006	85			30505001, 30500101, 30500102, 30505010, 30601101	0418	10	0
Auto and Light Duty Trucks	IIII	4/26/2007	40			40201601 to 40201632; 40201699	0702	0	0
Coke Ovens: Pushing, Quenching and Battery Stacks	CCCCC	4/14/2006	0			30300304; 30300303	0303	10	0
Fabric Printing, Coating & Dyeing	OOOO	5/29/2006	60			40201101 to 40201199; 40201201; 40201210	0713	10	0
Integrated Iron and Steel	FFFFF	5/20/2006	(5)		20	30301501 to 30301596	0305	0	10
Iron and Steel Foundries	EEEEE	4/22/2007	5			304003XX, 304007XX	0308	5	0
Lime Manufacturing	AAAAA	1/5/2007			23	305016XX	0408	0	10
Metal Can	KKKK	11/13/2006	70			40201702; 40201703 to 40201799	0707	0	0
Metal Furniture	RRRR	5/23/2006	0			402020XX		10	0
Misc. Coating Manufacturing	HHHHH	12/11/2006	64			402026XX	1642	10	0
Misc. Metal Parts and Products	MMMM	1/2/2007	0			402025XX		10	0
Misc. Organic Chemical Production and Processes (MON)	FFFF	11/10/2006	66			645200XX; 30113001 to 30113007; 684300XX; 30101005 to 30101099; 68445001; 68445010; 68445013; 68445020; 68445022; 68445101; 68445201; 30110002 to 30110099; 64820001; 64820010; 64821001; 64821010; 64822001; 64822010; 64823001; 64823010; 64823001; 64823010; 64880001; 64882001; 64882002; 64882599; 30105001; 30105101 to 30105130; 30801001; 31604001; 31604002; 31600403; 68510001; 68510010; 68510011; 68580001; 68582001; 68582002; 68582599; 30101837; 64610301 to 64610350; 64610001 to 64610050; 64610101 to 64610150;	1641	10	0

Table III-2 (continued)

MACT Standard – Source Category	Code of Federal Regulations Subpart	Compliance Date (existing sources)	VOC (% Reduction)	NO_x (% Reduction)	Total PM (% Reduction)	Affected SCCs	MACT Code	Wisconsin and Michigan Values	
								VOC	PM
						64610201 to 64610250; 64615001 to 64615030; 64620001 to 64620038; 64630001 to 64630083; 64631001 to 64631083; 64632001 to 64632083; 64680001; 64682001; 64682002; 64682501; 64682502; 64682599; 64130001 to 64130025; 64130101 to 64130125; 64130201 to 64130225; 64131010 to 64131030; 64132001 to 64132030; 64133001 to 64133030; 64180001; 64182001; 64182002; 64182599; 64615001; 64620001; 65135001			
Organic Liquids Distribution	EEEE	2/3/2007	70			40300102, 40300104, 40300106, 40300107, 40301010-40301021	0602	10	0
Plastic Parts	PPPP	4/19/2007	0			402022XX		10	0
Plywood and Composite Wood Products	DDDD	10/1/2007	54			307007XX; 30700921 to 30700971; 30701001 to 30701057; 30700602 to 30700661	1624		
Refractory Products Manufacturing	SSSSS	4/17/2006	81	0			0406	10	0
Reinforced Plastic Composites Production	WWWW	4/21/2006	39	0			1337	10	0
Site Remediation	GGGGG	10/8/2006	50	0		504001XX; 50400201, 50400202; 504002XX; 504100XX; 504101XX; 504102XX; 504103XX; 504102XX; 504103XX; 04104XX; 504105XX; 504106XX; 504107XX; 50480001; 50482001; 50482002; 50482599; 50480004	0805	10	0

Table III-2 (continued)

MACT Standard – Source Category	Code of Federal Regulations Subpart	Compliance Date (existing sources)	VOC (% Reduction)	NO_x (% Reduction)	Total PM (% Reduction)	Affected SCCs	MACT Code	Wisconsin and Michigan Values	
								VOC	PM
Stationary Combustion Turbines	YYYY	3/5/2007	13	17		20100101, 20100201, 20200101, 20200103, 20200201, 20200203, 20200901, 20300102, 20300202, 20300203	0105	0	0
Taconite Iron Ore Processing	RRRRR	10/30/2006	0	0	62	32302371 to 32302399	0411	0	10
Wood Building Products	QQQQ	5/28/2006	63	0		40202101 to 40202199	0703	10	0

**Based on organic hazardous air pollutant (HAP) emission reductions

Table III-3. LADCO State Non-EGU Point Sources Affected by Consent Decree Requirements and Other On-the-Books Controls

Identification Codes						FCCU Requirements		Heater/Boiler Requirements	
State	County	Facility*	Company	Location	State	SO_2	NO_x	SO_2	NO_x
18	089	00003	BP Amoco	Whiting	IN	FCU 500: Install wet gas scrubber; FCU 600: Use SO_2 adsorbing catalyst additive and/or hydrotreatment.	FCU 600: Install SCR; FCU 500: Low NO_x combustion promoter and NO_x adsorbing catalyst additive	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tons per year (tpy).
39	095	0448010246	BP Amoco	Toledo	OH	SO_2 catalyst additive	Install SNCR system	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
17	197	197090AAI	CITGO Global Refinery	Lemont	IL	New wet gas scrubber	Low NO_x combustion promoter (20 ppmvd limit)	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from listed units by at least 50% of the revised baseline
17	119	119090AAA	Conoco Philips Global Refinery	Roxanna (Wood River)	IL	Install new wet gas scrubber (25 ppmvd or lower)	FCCU 1: Scrubber-based NO_x emission reduction technology to achieve 20 ppmvd	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
17	119	119090AAA	Conoco Philips Global Refinery	Hartford (Wood River)	IL	Install new wet gas scrubber (25 ppmvd or lower)	FCCU 2: Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
17	197	197800AAA	Exxon-Mobil Refinery	Joliet	IL	Install new wet gas scrubber (25 ppmvd or lower)	Install and operate an SCR system	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Use qualifying controls to reduce NO_x emissions from combustion units
17	033	033808AAB	Marathon Ashland Refinery	Robinson	IL	Existing wet gas scrubber	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.

Table III-3 (continued)

Identification Codes						FCCU Requirements		Heater/Boiler Requirements	
State	**County**	**Facility***	**Company**	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
26	163	A9831	Marathon Ashland Refinery	Detroit	MI	SO_2 catalyst additive	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
27	163	2716300003	Marathon Ashland Refinery	St Paul Park	MN	New wet gas scrubber on unit 1; catalyst additive on other unit	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
39	151	1576000301	Marathon Ashland Refinery	Canton	OH	SO_2 catalyst additive	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
39	095	0448010246	Sunoco Petroleum Refinery	Toledo	OH	Install new wet gas scrubber to meet 25 ppmvd SO_2	Install SCR systems or alternate technology to meet 20 ppmvd	Accept NSPS Subpart J applicability and reduce or eliminate fuel oil burning	

Table III-3 (continued)

Identification Codes						
State	**County**	**Facility***	**Company**	**Location**	**State**	**Notes**
17	115	115015AAE	ADM	Decatur	IL	Settlement agreement
17	143	143065AJE	ADM	Peoria	IL	Settlement agreement
17	001	001815AAF	ADM	Quincy	IL	Settlement agreement
18	173	00002	Alcoa	Warrick Units 1,2,3	IN	Settlement agreement

*Facility identification codes are those used in the 2002 point source files.

The Michigan Department of Environmental Quality (DEQ) provided information about the expected emissions reductions associated with settlements affecting Michigan sources. The information from Michigan DEQ was provided for Severstal (iron and steel), US Steel, and Marathon refinery. For Severstal, the key information provided indicated that NO_x emissions after the summer 2007 would be reduced at the blast furnace B and C stoves via a low NO_x burner (LNB) installation. A 50 percent NO_x control factor was applied with 2007 implementation year based on information in the Ozone Transport Rulemaking analysis about the expected emission reduction of LNB applied to a blast furnace. For US Steel, the Michigan DEQ-provided information indicated that PM controls would be installed during 2005 or 2006 on the basic oxygen furnace and blast furnace B, so it was assumed that these were base year controls and no future year control factor was applied. For the Marathon refinery in Michigan, the Michigan DEQ estimated that catalyst additives applied to the FCCU would reduce NO_x emissions by 25-50 percent and SO_2 emissions by 60-80 percent. The midpoint of each range was used to estimate post-2005 control factors for this refinery. All other expected controls at Marathon are to reduce PM emissions and were assumed to have occurred by 2005, so no future year PM control factors were applied.

4. On-the-Books (OTB) Control Additions

Table III-3 lists on-the-books controls that were applied to individual facilities/sources in the future year control factor file. This information was developed from the OTB updated control factor file provided by LADCO from the 2002 base year projections. The compliance date information in this file was used to eliminate controls that had compliance dates of 2005 or earlier. Ohio EPA provided information about the expected effects of NO_x Reasonably Available Control Technology (RACT) rules in achieving post-2005 emission reductions in the Cleveland-Akron, Ohio 8-hour ozone nonattainment area. Table III-4 summarizes the source categories, associated emission control equipment to meet the requirements, and the estimated NO_x control percentages.

Table III-4. Ohio RACT Rule Summary Cleveland/Akron 8-Hour Ozone Nonattainment Area

Source Category	Unit Size (MMBtu/hour)	NO_x Control	Estimated NO_x Control Efficiency
RICE Engines	All	Low Emission Combustion	80%
ICI Boilers	20-49	Burner Tune-up	10%
ICI Boilers	50-99	LNB+FGR	61%
ICI Boilers	100-249	LNB+FGR	61%
ICI Boilers	>250	LNB+FGR	61%
Combustion Turbine	All	Dry LNB	70%

SOURCE: Ohio EPA Division of Air Pollution Control.

5. Best Available Retrofit Technology (BART)

Table III-5 lists the BART-eligible sources for the states in the LADCO study region. In instances where criteria air pollutant control percentages (for SO_2 and NO_x) are listed in this table, those control percentages were applied in estimating 2018 emissions.

Table III-5. BART Eligible Non-EGU Sources

State	State ID	Source Name	County	County ID	Source ID	BART Emission Unit ID	Description	Stack ID	Est. Emission Reduction	
									SO_2	NO_x
ILLINOIS	17	Conoco Phillips	Madison	11D	119090AAA					
ILLINOIS	17	Exxon Mobil	Will	197	197800AAA					
ILLINOIS	17	CITGO	Will	197	197090AAI					
ILLINOIS	17	National Steel – Granite City	Madison	119	119813AAI					
INDIANA	18	AGC DIVISION-ALCOA POWER GENERATING	Warrick	173	2	Boiler #2	Dry Bottom, pulverized coal-fired boiler	241-242	95	90
						Boiler #3	Dry Bottom pulverized coal-fired boiler	242	95	90
						Boiler #4	Dry Bottom, pulverized coal-fired boiler	243	95	90
INDIANA	18	Alcoa Inc. – Warrick	Warrick	173	7	105m.1, 10	POTLINE #3. ROOMS 105 AND 106 gtc	105M	95	40
						107M, 108M	POTLINE #4. ROOMS 107 AND 108 GTC	107M	95	40
						109M,110M	POTLINE #5, ROOMS 109 AND 110, A-398	109M	95	40
						111M,112M,	POTLINE #6		95	40
						130m.1,104	potline #2, Rooms 103 and 104, A-398	103m.1	95	40
						134.63	HDC FURNACE COMLEXES	1EH	0	40
						134.71	OFFLINES #2	134.71	0	40
INDIANA	18	ESSROC CEMENT CORP. (Speed)	Clark	19	8	EU20	Kiln #1		95	70
						EU21	Kiln #2		95	70
INDIANA	18	GE PLASTICS MT. VERNON INC.	Posey	129	2	08-706	CO AND ORGANIC SULFIDE STREAM FROM PHOSGENE FED	08-706 707	95	0
						09-001	B&W NATURAL GAS AND OIL FIRED BOILER	09-001	0	70
						09-001	Riley Boiler	12-001	95	70
						12-001	Hot Oil Heater		0	0
						09-002	LASKER BOILER	09-002	95	75
						09-002	ERIE BOILER	09-002	95	75

Table III-5 (continued)

State	State ID	Source Name	County	County ID	Source ID	BART Emission Unit ID	Description	Stack ID	Est. Emission Reduction	
									SO_2	NO_x
INDIANA	18	ISG-BURNS HARBOR (Formerly Beth. Steel)	Porter	127	1	460-01	#7 Boiler	4	95	75
						46002	#8 Boiler	5	95	75
						460-03	#9 Boiler	6	95	75
						460-04	#10 Boiler	7	95	75
						460-05	Boiler #11	8	95	75
						460-06	#12 Boiler	9	95	75
						512-06	#1 COKE BATTERY PUSHING	11	0	0
						512-08	#1 Coke Battery Underfire	13	95	75
						512-14	#2 COKE BATTERY PUSHING	12	0	0
						512-16	#2 COKE BATTERY UNDERFIRE STACK	14	95	75
						520	BLAST FURNACE FUGITIVES		0	0
						520-04	SINTER WINDBOX STACK	25	95	75
						520-18	BLAST FURNACE D CASTHOUSE EMISSIONS	33	0	0
						520-18	C BLAST FURNACE STOVES	31	0	0
						520-19	BLAST FURNACE D STOVES	34	0	0
						520-19	BLAST FURNACE C CASTHOUSE	33	0	0
						534	STEELMAKING FUGITIVES		0	0
						534-01	STEELMAKING HMD STATION #1	57	0	0
						534-02	STEELMAKING HMD #2	59	0	0
						534-10	STEELMAKING VESSELS #1 & #2	62	0	0
						534-11	STEELMAKING VESSELS	64	0	0
						534-23	STEELMAKING FM BOILER	65	0	0

Table III-5 (continued)

State	State ID	Source Name	County	County ID	Source ID	BART Emission Unit ID	Description	Stack ID	Est. Emission Reduction	
									SO_2	NO_x
						595-24	CASTER #1	80	0	0
						670-05	HOT STRIP FURNACE #1	90	95	75
						670-07	HOT STRIP #3 FURNACE	92	95	75
						670-07	HOT STRIP	91	95	75
						673-14	160" OKATE MILL FURNACE #1	112	0	75
						673-15	160" PLATE MILL FURNACE #2	113	0	75
						673-16.17	160" PLATE MILL FURNACES 4&5	110	0	0
						673-18.19	160" PLATE MILL FURNACES 6&7	111	0	0
						673-20	160" PLATE MILL FURNACE #8	114	0	0
						674.26,27	110" PLATE MILL FURNACES #1	122	0	0
MICHIGAN	26	Lafarge Midwest Inc.	Alpena	7	B1477	Kilns #1-#5				
MICHIGAN	26	Stone Container Corp.	Ontonagon	131	A5754	Riley Boiler				
						Paper Machine #2				
MICHIGAN	26	Tilden Mining Co	Marquette	103	B4885	Pelletizing Line #1, includes kiln, furnace, cooler, dryer				
						Boiler #2				
						Primary crusher				
MICHIGAN	26	Empire Iron Mining	Marquette	103	B1827	Pelletizing Lines #1 - #3 furnace				
						Boilers #1 - #3				
						Primary crusher				
MICHIGAN	26	St. Mary's Cement (CEMEX)	Charlevoix	29	B1559	Kiln and pre-calciner				
MICHIGAN	26	New Page Paper (Escanaba)	Delta	41	A0884	Boiler #8				
						Boiler #9				
						Recovery furnace				
						Lime kiln				
MINNESOTA	27	Ipsat Inland	St. Louis	137	2713700062					
MINNESOTA	27	EVTAC-Fairlane	St. Louis	137	2713700113					
MINNESOTA	27	National Steel (Keewatin)	St. Louis	137	2713700063					
MINNESOTA	27	Hibbing Taconite	St. Louis	137	2713700061					
MINNESOTA	27	USS Minntac	St. Louis	137	2713700005					
MINNESOTA	27	Northshore Mining	Lake	75	2707500003					

Table III-5 (continued)

State	State ID	Source Name	County	County ID	Source ID	BART Emission Unit ID	Description	Stack ID	Est. Emission Reduction	
									SO_2	NO_x
N. DAKOTA	38	Great River Energy – Coal Creek	McLean	55	17					
N. DAKOTA	38	Basin Electric Power – Leland Olds	Mercer	57	1					
N. DAKOTA	38	Great River Energy – Stanton	Mercer	57	4					
N. DAKOTA	38	Minnkota Power – MR Young	Oliver	65	1					
OHIO	39	Mead Paper Division	Ross	67	671010028					
WISCONSIN	55	Georgia-Pacific Consumer Products (Formerly Fort James)	Brown	9	405032870	Boiler B26	stoker (coal, tire and other fuels), 350 mmBtu/hr	S10	85	50
						Boiler B27	cyclone, 615 mmBtu/hr	S10	85	88

B. AREA SOURCE/MAR CONTROLS

1. Area Sources

Pechan worked with the LADCO states to determine how to estimate the effect of federal/ state/local rules on area source category emissions. The sub-sections below describe the results of this effort.

a. VOC Solvent Categories

For VOC emissions from consumer products and architectural and maintenance coatings, it was decided to estimate post-2005 VOC emission reduction credits using EPA guidance to states for estimating the benefits of three Federal rules being promulgated during calendar year 2007 (Harnett, 2007). These rules will establish or amend VOC content limits for (1) aerosol coatings (new rule), (2) architectural and industrial maintenance (AIM) coatings (amendments), and (3) household and institutional consumer products (amendments).

EPA estimated that the aerosol coatings rule will achieve the equivalent of a 19 percent reduction in mass VOC emissions from the 1990 baseline. The year 1990 represents the baseline, since there has been no previous Federal rulemaking for aerosol coatings. The creditable reduction that may be claimed is 0.114 pounds per capita. In the LADCO state 2005 emission inventory, this VOC emission reduction is applied to SCC 2460500000, which are Coatings and related products. A 12 percent VOC emission reduction is applied to SCC 2460500000 in each forecast analysis year (i.e., 2009, 2012, and 2018) to estimate the benefit of the federal aerosol coatings rule. This percentage is lower than the equivalent value estimated by EPA because the aerosol coatings rule is a subset of the Coatings and related products category represented by SCC 2460500000.

For AIM coatings, EPA estimates that the amended Federal AIM rule will achieve a reduction of 31 percent from the post-1998 Federal rule baseline of 3.6 pounds per capita. This is a creditable reduction of 1.1 pounds per capita. AIM coating emission reductions are applied to the following SCCs in the base year LADCO inventory for each analysis year: 2401001000; 2401002000; 2401003000; 2401008000; 2401008999.[2]

For consumer products, EPA has calculated that the amended Federal rule will achieve a VOC reduction of approximately 29 percent beyond that achieved by the 1998 Federal rule. This is a creditable reduction of 0.9 pounds per capita. Emission reductions from the Federal rule are applied to all Consumer Product source categories (SCCs 2460*) in each analysis year.

b. Portable Fuel Containers

For portable fuel containers (PFCs), while there are state-by-state differences in likely rule adoption dates, all state's control factors are based on the EPA mobile source air toxics (MSAT) rule requirements. EPA adopted emission standards for portable fuel containers (such as gas

[2] Note that subsequent to delivery of the area source/MAR control file, Wisconsin stated that this last SCC should not be included for their state.

cans) under the consumer products authority of the Clean Air Act. Starting with containers manufactured in 2009, the standard limits evaporation and permeation emissions from these containers to 0.3 grams of hydrocarbons per gallon per day. EPA also adopted test procedures and a certification and compliance program in order to ensure that containers meet the emission standard over a range of in-use conditions.

The VOC emission reduction benefits were estimated assuming that the new rule affects PFC sales starting during 2009, and that each PFC that meets the MSAT standard has 75 percent lower emissions than the PFC being replaced.

To account for the fact that growth in the portable fuel container population and turnover from old to new containers will be affected by the MSAT rule,[3] Pechan calculated projection year emissions using the following equation:

$$Q_N = Q_O \left\{ \left[\left(G_N \right) - 1 \right] F_n + \left[\left(1 - R_i \right)^t \right] F_e + \left[1 - \left(1 - R_i \right)^t \right] F_n \right\} \qquad \textit{(Eq. 1)}$$

where:

Q_N = emissions in projection year
Q_o = emissions in base year
R_i = annual retirement rate
F_e = emission factor ratio for existing sources (1.0)
G_N = projection year growth factor (projection year activity/base year activity)
F_n = emission factor ratio for new sources relative to existing sources
t = number of years between base year (2002) and projection year

The first term in the equation represents new source growth and controls, the second term accounts for retirement and controls for existing sources, and the third term accounts for replacement source controls. Because retirement was not estimated using a constant annual rate (5 percent were assumed to be retired in the first year, with 10 percent retired in each additional forecast year), Pechan replaced the $(1\text{-}R_i)^t$ terms in this equation with the appropriate proportion of containers retired between the base year and the appropriate forecast year. Pechan then computed an overall emission reduction for each future year of interest by comparing the forecast year controlled emissions calculated from this equation to the forecast year uncontrolled emissions. For example, an overall VOC emission reduction of 26.4 percent was computed for Illinois. Pechan then back-calculated the appropriate rule penetration (RP) value for each forecast year based on the overall emissions reduction, the 75 percent CE value, and an rule effectiveness (RE) of 100 percent (e.g., the calculated RP for Illinois for 2012 is 35.2 percent).

[3] Note that to simplify the analysis Pechan assumed that all post-2005 new container growth would be affected by the MSAT rule (due to low growth rates, this assumption does not have a significant impact on the overall emission reduction estimates of this rule).

c. Residential Wood Heating (Woodstoves and Fireplace Inserts)

Pechan developed control factors by pollutant and year to account for the effect of the replacement of retired wood stoves/inserts that emit at pre-residential wood heater new source performance standard (NSPS) levels,. These control factors were developed using an annual 2 percent retirement rate for wood stoves/fireplaces along with pre- and post-NSPS wood stove and fireplace emission factors. SCCs for "controlled" wood stoves and fireplace inserts have no control factors applied. Pechan developed updated residential wood combustion control factors for the LADCO states using the same algorithms applied previously (Pechan, 2004). Table III-6 displays the emission reduction, control efficiency, and rule penetration percentages modeled.

d. Stage II Vehicle Refueling

Pechan developed updated (2005 base year) Stage II vehicle refueling control factors via MOBILE runs for the LADCO states. Onroad refueling control factors were calculated based on the percentage difference between the projection year (2009, 2012, and 2018) MOBILE6 refueling emission factors and the 2005 MOBILE6 refueling emission factors.

MOBILE6 emission factors were calculated at January and July temperature and fuel conditions. July emission factors were used as the surrogate for the five-month ozone season (May through September) and the January emission factors were used as the surrogates for the remaining seven months. Temperatures modeled were the January and July average daily monthly maximum and minimum temperatures for each state (i.e., Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin) based on 30-year average temperature data, as used in EPA's second Section 812 Prospective analysis. MOBILE6 input files were created for each unique combination of: January and July Reid vapor pressure, reformulated gasoline, oxygenated fuel, gasoline sulfur, and Stage II control programs for each of the states mentioned above. Fuel data and Stage II control program information for each state and corresponding projection year were based on EPA's National Mobile Inventory Model (NMIM) County Database (version NDC20060201). Data extracted from NMIM's County Database for these input parameters were based on January and July values.

Stage II control programs for IL, IN, and WI began in 1998 with a phase-in year of one year and with a percent efficiency value of 86.0 percent for LDGVs and LDGTs in the program. Similarly, the HDGVs in the program have 86.0 percent efficiency. For Ohio, these control programs began in 1993 with a two-year phase-in and 77.0 percent efficiency for both the LDGVs + LDGTs and HDGVs in the program.

Modeling these temperature, fuel, and Stage II control inputs (where applicable), Pechan calculated MOBILE6 emission factors for calendar years 2005, 2009, 2012, and 2018.

The resulting MOBILE6 emission factors were first weighted according to the default MOBILE6 VMT mix to determine the weighted average refueling emission factor for all gasoline vehicle types. The resulting January and July emission factors were weighted together according to the number of days in the seven-month season (212 days) and the five-month ozone season (153).

Table III-6. Residential Wood Combustion NSPS Emission Reductions (percentage values)

SCC	SCC Description	Pollutant	2009			2012			2018		
			Reduction	Control Efficiency	Rule Penetration	Reduction	Control Efficiency	Rule Penetration	Reduction	Control Efficiency	Rule Penetration
2104008001	Total Fireplaces	CO	2.9	55.0	5.3	4.9	55.0	8.9	8.5	55.0	15.5
2104008010	Total Woodstoves	CO	3.1	55.0	5.6	5.2	55.0	9.5	9.0	55.0	16.4
2104008000	Total Fireplaces & Woodstoves	CO	3.0	55.0	5.5	5.1	55.0	9.3	8.9	55.0	16.2
2104008001	Total Fireplaces	NOX	1.9	28.6	6.6	3.3	28.6	11.5	5.6	28.6	19.6
2104008010	Total Woodstoves	NOX	2.0	28.6	7.0	3.4	28.6	11.9	5.8	28.6	20.3
2104008000	Total Fireplaces & Woodstoves	NOX	2.0	28.6	7.0	3.3	28.6	11.5	5.8	28.6	20.3
2104008001	Total Fireplaces	PM10-PRI	2.3	35.9	6.4	4.0	35.9	11.1	6.9	35.9	19.2
2104008010	Total Woodstoves	PM10-PRI	2.5	35.9	7.0	4.2	35.9	11.7	7.2	35.9	20.1
2104008000	Total Fireplaces & Woodstoves	PM10-PRI	2.4	35.9	6.7	4.1	35.9	11.4	7.1	35.9	19.8
2104008001	Total Fireplaces	PM25-PRI	2.3	35.9	6.4	4.0	35.9	11.1	6.9	35.9	19.2
2104008010	Total Woodstoves	PM25-PRI	2.5	35.9	7.0	4.2	35.9	11.7	7.2	35.9	20.1
2104008000	Total Fireplaces & Woodstoves	PM25-PRI	2.4	35.9	6.7	4.1	35.9	11.4	7.1	35.9	19.8
2104008001	Total Fireplaces	VOC	5.9	77.4	7.6	9.8	77.4	12.7	17.1	77.4	22.1
2104008010	Total Woodstoves	VOC	5.6	77.4	7.2	9.4	77.4	12.1	16.4	77.4	21.2
2104008000	Total Fireplaces & Woodstoves	VOC	5.4	77.4	7.0	9.2	77.4	11.9	16.0	77.4	20.7

Note: Rule effectiveness (RE) of 100 percent for each SCC/year.

After this was done for all of the modeled years and state or sub-state areas, the overall control efficiency for refueling, due to fleet turnover, was calculated based on the percentage difference between the 2005 and corresponding projection year emission factors. These control efficiencies were then assigned to individual counties, based on the mapping of fuel and Stage II control parameters to those modeled in the MOBILE6 files.

2. MAR Sources (Locomotives and Marine Vessels)

EPA issued a proposed rule this spring affecting future criteria pollutant emissions from railroad locomotives and commercial marine vessels (CMVs) (EPA, 2007b). These are the two off-road source categories that are addressed in this report. Base year emissions (2005) information for these two source categories was developed by ENVIRON under contract to LADCO (ENVIRON, 2007a and b).

Control factors for criteria air pollutants were developed using Chapter 3 (Emissions Inventory) of EPA's "Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression-Ignition Engines Less than 30 Liters per Cylinder" (EPA, 2007b). This chapter presents EPA's analysis of the emissions impact of the proposed rule for three source categories affected: commercial marine diesel engines, recreational marine diesel engines, and locomotives. The proposed control requirements include NOx and PM emission standards for Category 1 and Category 2 commercial marine diesel engines (both above and below 37 kilowatts). New NOx and PM emission standards would also apply to all recreational diesel engines and locomotives. There are no new standards for HC or CO; however, the PM standards are also expected to decrease HC emissions.

For locomotives, the EPA Regulatory Impact Analysis (RIA) chapter was used to develop 2009, 2012 and 2018 estimates of baseline and post-control emissions by pollutant by locomotive usage. This information is summarized in Table III-7. The RIA examined the effect of the proposed rule on emissions for (1) large line haul, (2) large switch, (3) small railroads, and (4) passenger commuter trains. Each of these four usage types was assigned to the base year 2005 emission inventory SCCs. The SCC assignments are shown at the bottom of Table III-7.

Table III-7. Locomotive Emissions Reported in EPA Draft RIA

Year	Large Line Haul		Large Switch		Small Railroads		Passenger Commuter	
	Baseline	Controlled	Baseline	Controlled	Baseline	Controlled	Baseline	Controlled
Volatile Organic Compounds								
2006	43,874		5,501		2,891		1,609	
2009	43,486	42,008	5,696	5,552	3,032	3,032	1,546	1546
2012	42,891	35,890	5,898	5,364	3,179	3,179	1,476	1301
2018	41,684	23,607	6,325	5,066	3,497	3,497	1,332	771
PM-2.5								
2006	27,082		2,202		907		992	
2009	24,216	23,661	2,120	2,070	870	870	861	861
2012	23,800	20,672	2,188	2,006	912	912	819	738
2018	22,542	14,516	2,309	1,896	991	991	719	466
PM-10								
2006	27,919		2,270		935		1,023	
2009	24,965	24,393	2,185	2,134	897	897	888	888
2012	24,536	21,311	2,256	2,068	940	940	845	761
2018	23,240	14,965	2,380	1,954	1,022	1,022	741	480
Oxides of Nitrogen								
2006	779,842		86,861		37,690		38,466	
2009	755,490	751,364	88,573	87,999	39,528	39,528	32,338	32,338
2012	730,031	692,606	88,909	86,614	41,456	41,456	27,212	25,933
2018	708,525	608,010	90,875	84,612	44,299	44,299	22,559	19,496
SCC(s)	2285002006		2285002010		2285002007		2285002008; 2285002009	

Because the federal locomotive emission standards modeled under previous LADCO contracts will continue to achieve emission reductions, it was necessary for Pechan to adjust the information in the new RIA to estimate the total post-base year reductions from the effects of both the existing and proposed locomotive standards. Pechan computed a revised set of projected emissions for modeling years 2009, 2012, and 2018 that reflect application of EPA's assumed locomotive growth rate (1.6 percent per year) to the base year (2006) emissions from their analysis. This step was used to estimate the emissions for each modeling year excluding the effects of both sets of emission standards. Next, Pechan computed the percentage reduction in emissions between the revised emissions in each modeling year and the controlled emissions reported in EPA's draft RIA. Table III-8 shows how the revised baseline and percent reduction for each modeling year. For example, for large line haul railroads, the baseline 2009 uncontrolled VOC emissions are estimated to be 46,014 tons nationally. Controlled emissions of 42,008 tons represent an 8.7 percent VOC reduction from this uncontrolled emission estimate (46,014 – 42,008 = 4,010; 4,010/46,014 * 100 = 8.7).

Table III-8. Percentage Reductions Associated with Federal Locomotive Standards

Year	Large Line Haul		Large Switch		Small Railroads		Passenger Commuter	
	Revised Baseline	% Reduction	Revised Baseline	% Reduction	Revised Baseline	% Reduction	Revised Baseline	% Reduction
Volatile Organic Compounds								
2006								
2009	46,014	8.7%	5,769	3.8%	3,032	0.0%	1,687	8.4%
2012	48,258	25.6%	6,051	11.3%	3,180	0.0%	1,770	26.5%
2018	53,080	55.5%	6,655	23.9%	3,498	0.0%	1,947	60.4%
PM-2.5								
2006								
2009	28,403	16.7%	2,309	10.4%	951	8.5%	1,040	17.2%
2012	29,788	30.6%	2,422	17.2%	998	8.6%	1,091	32.4%
2018	32,765	55.7%	2,664	28.8%	1,097	9.7%	1,200	61.2%
PM-10								
2006								
2009	29,281	16.7%	2,381	10.4%	981	8.5%	1,073	17.2%
2012	30,709	30.6%	2,497	17.2%	1,028	8.6%	1,125	32.4%
2018	33,777	55.7%	2,746	28.9%	1,131	9.7%	1,238	61.2%
Oxides of Nitrogen								
2006								
2009	817,877	8.1%	91,097	3.4%	39,528	0.0%	40,342	19.8%
2012	857,766	19.3%	95,540	9.3%	41,456	0.0%	42,310	38.7%
2018	943,477	35.6%	105,087	19.5%	45,599	2.8%	46,537	58.1%
SCC(s)	2285002006		2285002010		2285002007		2285002008; 2285002009	

Note: emissions reported in short tons.

Analogous control factor calculations to those described above for locomotives were used to compute total CMV emission reduction values representing the effects of both existing and proposed emission standards. Table III-9 presents the EPA baseline emissions, Pechan's revised baseline emissions (computed using EPA's 0.9 percent annual growth assumption), EPA's controlled emissions, and the percentage reduction estimates applied in this analysis. For example, the CMV standards are expected to reduce VOC emissions by 33.9 percent in 2018.

Table III-9. Percentage Reductions Associated with Federal CMV Standards

Year	Emissions (short tons)			
	Baseline	Revised Baseline	Controlled	% Reduction
Volatile Organic Compounds				
2005	17,295			
2009	16,870	17,926	16,863	5.9%
2012	16,495	18,414	16,344	11.2%
2018	16,034	19,431	12,851	33.9%
PM-2.5				
2005	30,042			
2009	27,327	31,138	27,324	12.2%
2012	26,657	31,987	26,582	16.9%
2018	22,553	33,753	19,308	42.8%
PM-10				
2005	30,972			
2009	28,172	32,102	28,169	12.3%
2012	27,481	32,977	27,403	16.9%
2018	23,251	34,798	19,905	42.8%
Oxides of Nitrogen				
2005	825,229			
2009	781,105	855,341	781,105	8.7%
2012	743,915	878,643	742,453	15.5%
2018	686,966	927,171	591,991	36.2%
Sulfur Dioxide				
2005	82,543			
2009	46,838	85,555	46,839	45.3%
2012	42,515	87,886	42,515	51.6%
2018	6,054	92,740	5,630	93.9%
Carbon Monoxide				
2005	153,499			
2009	149,966	159,100	149,966	5.7%
2012	146,227	163,434	146,227	10.5%
2018	140,443	172,461	140,443	18.6%

For commercial marine diesel engines, the RIA examines expected rule emission benefits for four different engine types/sizes. The total CMV emission benefits in each year were used and applied equally to most of the affected SCCs in the 2005 inventory. However, Pechan applied rule penetration (RP) values to two CMV SCCs based on an ENVIRON table indicating RP values of less than 100 percent for these SCCs (see Table III-10).

Table III-10. Commercial Marine Vessel Rule Penetration Values

Source Category Code (SCC)	Source Definition	Purpose	Geographic Area	Percentage of Engines Affected by Proposed EPA Standards				
				NOx	PM-10	HC	CO	SOx
2280002023	Push Boats	Barge Freight	River Traffic	100%	100%	100%	100%	100%
			Lake Traffic	100%	100%	100%	100%	100%
2280002021	Tugs	Vessel assist and support functions	Near port	100%	100%	100%	100%	100%
2280003200	Deep draft	Laker and ocean-going large vessels	Mid-Great Lakes	85%	81%	86%	86%	77%
2280003100			Near port	81%	71%	87%	83%	63%
2280002022	Ferries	River or lake ferrying	Regular routes	100%	100%	100%	100%	100%
2280002024	Other Commercial Vessels	Excursion boats primarily	Near dock	100%	100%	100%	100%	100%
2280002025	Dredges	Dredging projects	Varies	100%	100%	100%	100%	100%
2280002029	Support Vessels	General work boats	Near port	100%	100%	100%	100%	100%
2280002030, 2280004030[1]	Commercial Fishing	Market fishing	Great Lakes	100%	100%	100%	100%	100%
2280002040, 2280004040[1]	Military	Coast Guard and Navy	Great Lakes	100%	100%	100%	100%	100%

SECTION IV. PREPARATION OF GROWTH AND CONTROL FILES

This section describes the contents of the growth and control factor files submitted to LADCO earlier this month. The first subsection discusses the preparation of the point and area source/ MAR factor file and the revised NONROAD model growth file. The final subsection describes the contents of the control factor files.

Table IV-1 presents the RPO Data Exchange Protocol Format for reporting emission growth and control data. Pechan utilized this format to create growth and control factor files for LADCO. Because the growth factors (unlike the control factors) do not differ by pollutant, Pechan developed a separate file containing only the point and area source/MAR growth factors. Pechan revised the growth packet portion of the NONROAD model growth file (***NATION.GRW***) to replace the default model equipment population growth rates with growth rates based on more recent/more region-specific information. Two sets of control factor files were prepared: one for area source/MAR categories and one for point source categories. The point and area source/MAR growth and control files were developed in fixed field ascii format. The format of the default NONROAD model growth file was retained in the revised version prepared for LADCO. The following subsections describe the contents of the growth and control factor files.

A. GROWTH FACTORS

Pechan compiled the LADCO region growth factor information into the file ***$LADCO_2005_GF_Final_RPO.txt***. Table IV-2 displays the RPO Data Exchange Protocol Format fields and identifies the fields that were populated in this file. The file contains separate records for each SCC/state for each year between 2006 and 2018 (population-based growth indicator records are reported by SCC/state/county because population projections were available at the county-level).

Pechan revised the input file used by the NONROAD model (***NATION.GRW***) to reflect historical equipment population changes and to estimate future equipment population changes. In particular, Pechan incorporated LADCO state-specific records to the GROWTH packet portion of this file. The fixed field format of the data in this packet is as follows:

Characters	**Description**
1-5	FIPS code (00000 = applies to entire nation; ss000 = applies to all of state ss)
6-10	subregion code (left blank)
11-15	year of estimate (4-digit year)
17-20	indicator code (alphanumeric code identified within NONROAD)
26-45	value for indicator

Table IV-1. RPO Data Exchange Protocol Format for Growth/Control Data

Field Name	Field Description	Field Length
RECORD TYPE	A code that identifies the type of record (G for growth, C for control)	2
COUNTRY CODE	A code that identifies the country (US = United States)	2
STATE PROVINCE TRIBAL CODE	The code for the state/province/tribe	4
COUNTY FIPS	The FIPS code for the county	3
SIC	4-digit SIC, or 2 digit SIC with remaining digits blank (not zero)	4
SCC	EPA source classification code or a fraction of the code	10
SITE ID	Unique state/local/tribal ID reported consistently over time	15
EMISSION UNIT ID	Unique state/local/tribal ID reported consistently over time	6
EMISSION RELEASE POINT ID	State/ local/tribal ID for point /location where emissions are released to ambient air	6
POLLUTANT CODE	Pollutant code	9
PROCESS ID	Unique state/local/tribal ID reported consistently over time	6
BASE DATE	Date that the control strategy comes into effect	6
FUTURE DATE	Future date that the control strategy affects	6
PRIMARY CONTROL EQUIPMENT CODE	Primary control equipment code	10
BASE DATE CONTROL EFFICIENCY	Base year % control efficiency(60% reduction = 60)	6
FUTURE DATE CONTROL EFFICIENCY	Future year % control efficiency(60% reduction = 60)	6
FUTURE DATE GROWTH FACTOR	Growth factor based on changes in throughput, economic growth (unrelated to controls). This is an absolute growth rate not an annual growth rate.	11
CONTROL TYPE	MACT, RACT, LAER, SIPCALL, BART, etc	10
FUTURE DATE CHEMICAL SPECIATION PROFILE	Code matching speciate chemical speciation profile unless in base year	6
ALLOWABLE EMISSIONS CAP	Allowable emissions cap units must be in TONS/day	10
MARKET PENETRATION OF NEW SPECIATION PROFILE	Fraction of future year emissions using new speciation profile	6
RESERVED FOR FUTURE USE FIELD 3	(Field used to enter future year control efficiency value where available)	10
RESERVED FOR FUTURE USE FIELD 2	(Field used to enter future year rule effectiveness value where available)	10
RESERVED FOR FUTURE USE FIELD 1	(Field used to enter future year RP value where available)	10
CONTROL DESCRIPTION	A text description of the control	80
PRIMARY CONTACT	Email address of the primary contact/developer of this record	30

Table IV-2. Fields Populated in Growth Factor File

Field Name	Populated in Growth Factor File?
RECORD TYPE	Yes
COUNTRY CODE	Yes
STATE PROVINCE TRIBAL CODE	Yes
COUNTY FIPS	Yes (with "000" except for population data)
SIC	No
SCC	Yes
SITE ID	No
EMISSION UNIT ID	No
EMISSION RELEASE POINT ID	No
POLLUTANT CODE	No
PROCESS ID	No
BASE DATE	Yes
FUTURE DATE	Yes
PRIMARY CONTROL EQUIPMENT CODE	No
BASE DATE CONTROL EFFICIENCY	No
FUTURE DATE CONTROL EFFICIENCY	No
FUTURE DATE GROWTH FACTOR	Yes
CONTROL TYPE	No
FUTURE DATE CHEMICAL SPECIATION PROFILE	No
ALLOWABLE EMISSIONS CAP	No
MARKET PENETRATION OF NEW SPECIATION PROFILE	No
RESERVED FOR FUTURE USE FIELD 3 *(future year CE)*	No
RESERVED FOR FUTURE USE FIELD 2 *(future year RE)*	No
RESERVED FOR FUTURE USE FIELD 1 *(future year RP)*	No
CONTROL DESCRIPTION	No
PRIMARY CONTACT	Yes

B. CONTROL FACTORS

Pechan compiled control factors for the LADCO states in two sets of ascii files: one set for point source controls (***LADCO 2005 Base Year Point Control File.txt***), and the other set for area source/MAR controls (***LADCO 2005 Base Year Area Source and MAR Control File.txt***).

1. Point Source Control Factors

The ***LADCO 2005 Base Year Point Control File.txt*** file reports control information at the Process ID-level and for the specific date that each control is expected to be implemented. Note that the Base Date Control Efficiency field is populated with a zero for every record because Pechan did not have any base year control information other than that reported in the base year inventory supplied by LADCO. LADCO should rely on the control information in the base year inventory to identify the base year level of control. For MACT standards, the point source control factors are incremental to base year control levels. Because all other point source control

factors represent absolute control levels, LADCO should subtract any existing 2005 inventory level of control from the control factor level of control to determine net reductions for non-MACT controls. Pechan found very few point source records with control information, so LADCO should expect very little control overlap between the 2005 inventory and the control file. Table IV-3 identifies the RPO Data Exchange Protocol fields that are populated in the point source control file.

2. Area Source and MAR Control Factors

Pechan compiled the area source and MAR control factor information into a single ascii file that reports the level of control for each year of interest (2009, 2012, and 2018). In cases where there is no change in emission reduction after the initial implementation year, the level of control is repeated for each year. For controls where emission reductions increase over time (due to increased levels of RP), the level of control increases for each successive modeling year. Except for the single control for which emission reductions are county-specific (Stage II Vehicle Refueling), the area source and MAR control factor file is expressed at the state-level. In cases where it was feasible to do so, Pechan populated the 5th, 4th, and 3rd fields from the end of each control factor file ("RESERVED FOR FUTURE USE" in the RPO Data Exchange Protocol Format) with future year CE, RE, and RP values, respectively (the field "FUTURE DATE CONTROL EFFICIENCY" was populated with the overall percentage emission reduction). Table IV-4 identifies the RPO Data Exchange Protocol fields that are populated in this file.

Table IV-3. Fields Populated in Point Source Control Factor File

RPO Data Exchange Protocol Format Field Name	Populated in Point Source Control Factor File
RECORD TYPE	Yes
COUNTRY CODE	Yes
STATE PROVINCE TRIBAL CODE	Yes
COUNTY FIPS	Yes
SIC	Yes
SCC	Yes
SITE ID	Yes
EMISSION UNIT ID	Yes
EMISSION RELEASE POINT ID	Yes
POLLUTANT CODE	Yes
PROCESS ID	Yes
BASE DATE	Yes
FUTURE DATE[1]	Yes
PRIMARY CONTROL EQUIPMENT CODE	No
BASE DATE CONTROL EFFICIENCY[2]	Yes
FUTURE DATE CONTROL EFFICIENCY[3]	Yes
FUTURE DATE GROWTH FACTOR	No
CONTROL TYPE	Yes
FUTURE DATE CHEMICAL SPECIATION PROFILE	No
ALLOWABLE EMISSIONS CAP	No
MARKET PENETRATION OF NEW SPECIATION PROFILE	No
RESERVED FOR FUTURE USE FIELD 3 *(future year CE)*	No
RESERVED FOR FUTURE USE FIELD 2 *(future year RE)*	No
RESERVED FOR FUTURE USE FIELD 1 *(future year RP)*	No
CONTROL DESCRIPTION	Yes
PRIMARY CONTACT	Yes

[1] Represents date that control is first implemented.
[2] All records populated with “0" - LADCO should rely on control information reported in base year inventory.
[3] Populated with overall percentage emission reduction.

Table IV-4. Fields Populated in Area Source/MAR Control Factor File

RPO Data Exchange Protocol Format Field Name	Populated in Area Source/MAR Control Factor File
RECORD TYPE	Yes
COUNTRY CODE	Yes
STATE PROVINCE TRIBAL CODE	Yes
COUNTY FIPS	Yes
SIC	No
SCC	Yes
SITE ID	No
EMISSION UNIT ID	No
EMISSION RELEASE POINT ID	No
POLLUTANT CODE	Yes
PROCESS ID	No
BASE DATE	Yes
FUTURE DATE	Yes
PRIMARY CONTROL EQUIPMENT CODE	No
BASE DATE CONTROL EFFICIENCY	Yes
FUTURE DATE CONTROL EFFICIENCY[1]	Yes
FUTURE DATE GROWTH FACTOR	No
CONTROL TYPE	No
FUTURE DATE CHEMICAL SPECIATION PROFILE	No
ALLOWABLE EMISSIONS CAP	No
MARKET PENETRATION OF NEW SPECIATION PROFILE	No
RESERVED FOR FUTURE USE FIELD 3 *(future year CE)*	Yes[2]
RESERVED FOR FUTURE USE FIELD 2 *(future year RE)*	Yes[2]
RESERVED FOR FUTURE USE FIELD 1 *(future year RP)*	Yes[2]
CONTROL DESCRIPTION	Yes
PRIMARY CONTACT	Yes

[1] Populated with overall percentage emission reduction (product of CE, RE, and RP).
[2] Not populated for Federal locomotive standards or Stage II Vehicle Refueling control program.

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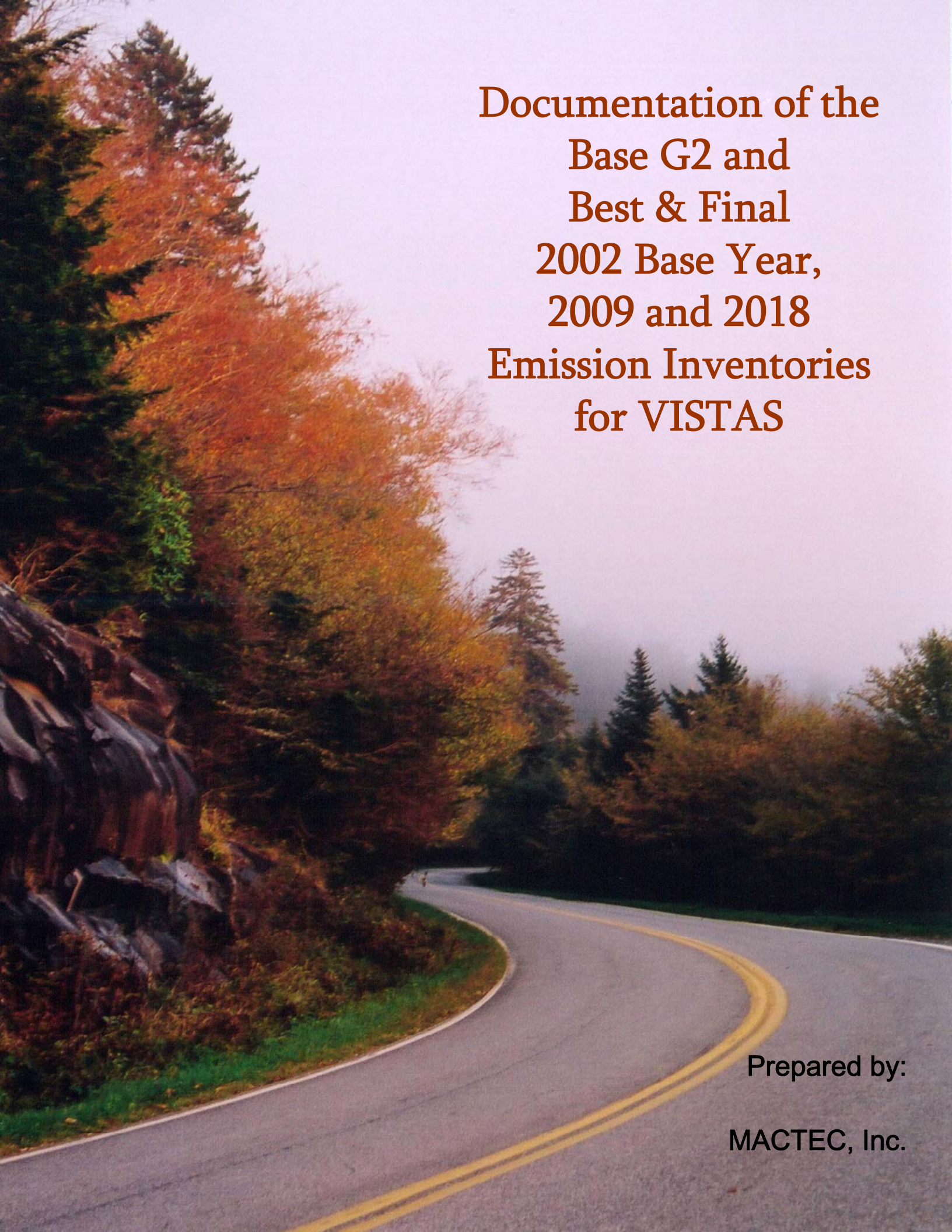

Documentation of the Base G2 and Best & Final 2002 Base Year, 2009 and 2018 Emission Inventories for VISTAS

Prepared by:

MACTEC, Inc.

Documentation of the
Base G2 and Best & Final
2002 Base Year, 2009 and 2018
Emission Inventories for VISTAS

Prepared for:

Visibility Improvement State and Tribal Association of the Southeast (VISTAS)

March 14, 2008

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
AF&PA	American Forest and Paper Association
APCD	Air Pollution Control District
ATP	Anti-Tampering Program
BLRID	Boiler Identification (Boiler ID)
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CEM	Continuous Emissions Monitoring
CAMD	Clean Air Markets Division
CERR	Consolidated Emissions Reporting Rule
CMU	Carnegie Mellon University
CMV	commercial marine vessels
CE	Control Efficiency
CO	carbon monoxide
DENR	North Carolina Department of Environment and Natural Resources
DHEC	South Carolina Department of Health and Environmental Control
EDMS	Emissions Data Management Systems
ESD	Emissions Standards Division
EPA	Environmental Protection Agency
EGU	Electric Generating Unit
ICF	ICF International, Inc.
FIP	Federal Implementation Plan
FLM	Federal Land Manager
FTP	File transfer protocol
FR	Federal Register
FS	Forest Service
HDD	Heavy Duty Diesel
HDD RULE	Heavy Duty Diesel Rule
ICF	ICF International, Inc.
ID	Identification
I/M	Inspection and Maintenance
IPM®	Integrated Planning Model®
IAQTR	Interstate Air Quality Transport Rule
LTO	Landing and take off
MACT	Maximum achievable control technology

Acronyms and Abbreviations (continued)

MACTEC	MACTEC Engineering and Consulting, Inc.
MOBILE 6	MOBILE emissions estimation model version 6
MRPO	Midwest Regional Planning Organization
NH_3	Ammonia
NEI	National Emission Inventory
NIF	National Emission Inventory Format
NLEV	National Low Emission Vehicle regulation
NMIM	National Mobile Inventory Model
NONROAD	no acronym (model name)
NO_x	Oxides of nitrogen
NWR	National Wildlife Refuge
OTB	On the books
OTW	On the way
ORIS	Office of Regulatory Information Systems
OTAQ	Office of Transportation and Air Quality
OTC	Ozone Transport Commission
PFC	Portable fuel containers
PM	Particulate matter
PM_{10}-FIL	Particulate matter less than or equal to 10 microns in diameter that can be captured on a filter
PM_{10}-PRI	Particulate matter less than or equal to 10 microns in diameter that includes both the filterable and condensable components of particulate matter
$PM_{2.5}$-FIL	Particulate matter less than or equal to 2.5 microns in diameter that can be captured on a filter
$PM_{2.5}$-PRI	Particulate matter less than or equal to 2.5 microns in diameter that includes both the filterable and condensable components of particulate matter
PM-CON	Particulate matter created by the condensation of hot materials to form particulates, usually less than 2.5 microns in diameter
ppmW	parts per million by weight
PRI	Primary
QA/QC	Quality Assurance/Quality Control
QAPP	Quality Assurance Project Plan
REMI	Regional Economic Models, Inc.
RFG	Reformulated gasoline
RVP	Reid Vapor Pressure

Acronyms and Abbreviations (continued)

SCC	Source Classification Code
SIP	State Implementation Plan
SIWG	Special Interest Workgroup
S/L/T	State/Local/Tribal
SMOKE	Sparse Matrix Operator Kernel Emissions Modeling System
S/L	State and Local
SO_2	Oxides of Sulfur
T4	Tier 4
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
VMT	Vehicle Miles Traveled
VOC	Volatile organic compounds
WRAP	Western Regional Air Partnership

Documentation of the Base G2 and Best & Final 2002 Base Year, 2009 and 2018, Emission Inventories for VISTAS

Introduction

Base G2 document was delivered final in Aug (?) 2007. In fall 2007 states updated specific point source EGU and non-EGU facility record in Best and Final (B&F) inventories for 2009 and 2018 to account for BART controls, consent decrees, corrections to Base G2, and source specific controls. Only EGU and non-EGU point source records were changed. Area, non-road, on-road remained the same as Base G2. In this report all records for area, non-road, and on-road were used in B&F modeling the same as Base G2. This report has been updated from the Base G2 report submitted in July 2007 just for B&F changes to EGU and non-EGU sources. A history of the development of the VISTAS inventory follows. Specific sections of the document detail the modifications made as the inventory progressed from Base F through B&F.

The Base G2 inventory included changes in 2018 controls on specific electric generating units in GA, FL, NC, and WV. There were no changes in 2009 controls for EGU and no changes between the Base G and Base G2 inventories for non-EGU point, on-road, non-road, or area sources in 2009 or 2018. The Base G2 modeling run included changes for 2018 EGU controls plus corrections in 2002 typical, 2009, and 2018 for errors in emissions processing in Base G. These corrections in emissions processing are not seen when comparing the Base G and G2 inventory files.

Base G and Base G2 inventories represent two separate model runs, as does the B&F. Since Base G2 supersedes Base G, VISTAS will maintain only the Base G2 and B&F model files since both were used in State Implementation Plan submittals.

History of VISTAS Base and Projection Year Emission Inventory Development

This section is provided to supply the history behind the development of the base and projection year inventories provided to the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) and the Association for Southeast Integrated Planning (ASIP). Through the various iterations, the inventories that have been developed have typically had version numbers provided by the contractors who developed the inventories and to a certain extent these were also based on their purpose. Different components of the 2002 base year inventories have been supplied by E.H. Pechan and Associates, Inc. (Pechan), MACTEC Engineering and Consulting, Inc.

(MACTEC), and by Alpine Geophysics, Inc. (AG). The projection year inventories were developed by MACTEC and AG.

The initial 2002 base year inventory was jointly developed by Pechan and MACTEC. Pechan developed the on-road and non-road mobile source components of the inventory while MACTEC developed the point and area source component of the inventory. This version of the inventory included updates to on-road mobile that incorporated information from the 1999 NEI Version 2 final along with updated information on VMT, fuel programs, and other inputs to the MOBILE6 model to produce a draft version of the 2002 inventory. For non-road sources, a similar approach was used. Updated State information on temperatures and fuel characteristics were obtained from VISTAS States and used with the NONROAD 2002 model to calculate 2002 emissions for NONROAD model sources. These estimates were coupled with data for commercial marine vessels, locomotives and airplanes projected to 2002 using appropriate growth surrogates. A draft version of these inventories was prepared in late 2003, with a final version in early 2004. An overview of the development of the on-road component can be found at: http://www.vistas-sesarm.org/documents/Pechan_drafton-roadinventory_082803.ppt while an overview of the non-road component can be found at: http://www.vistas-sesarm.org/documents/Pechan_Non-roadInventory_082803.ppt.

Similarly, draft versions of the 2002 point and area source base year inventories were prepared by MACTEC in the same timeframe (late 2003 for the draft, final in early 2004). The point source component was based on data submitted by the VISTAS States or on the 1999 NEI. The data submitted by the States ranged from 1999 to 2001 and was all projected to 2002 using appropriate growth surrogates from Economic Growth Analysis System (EGAS) version 4. Toxic Release Inventory (TRI) data were used to augment the inventory for NH_3. Continuous Emissions Monitor (CEM) data from the U.S. EPA's Clean Air Markets Division was used to supply emissions for electric generating utilities (EGUs). Particulate matter emissions were augmented (when missing) by using emission factor ratios. Details on all these calculations are discussed in Section 1.1.1.3 of this document.

The area source component of the 2002 draft base year emissions was prepared similarly to the point sources, using State submittals and the 1999 NEI Version 2 final as the basis for projecting emissions to 2002 using EGAS growth factors. For ammonia area sources the Carnegie Mellon University (CMU) ammonia model was used to calculate emissions. Finally, data on acreage burned on a fire by fire basis was solicited from State forestry agencies in order to calculate fire emissions on a fire by fire basis. Virtually all VISTAS State forestry agencies provided data for these calculations at least for wild and

prescribed fires. An overview of the point and area source development methods can be found at:
http://www.vistas-sesarm.org/documents/MACTEC_draftpointareainventory_82803.ppt.

Three interim versions of the 2002 base year inventory were developed. The first was delivered in August of 2003, the second in April of 2004 and the final one in October of 2004. The August 2003 and April 2004 inventories were prepared by MACTEC and Pechan. A draft version of the revised 2002 base year inventory was released in June of 2004, with a final version released in October 2004. That 2002 base year inventory was solely prepared by MACTEC. The October 2004 inventory incorporated 2002 Consolidated Emissions Reporting Rule (CERR) data into the inventory along with some updated data from the VISTAS States. This inventory is typically referred to as version 3.1 of the VISTAS inventory.

Closely following the version 3.1 2002 base year inventory, a "preliminary" 2018 projection inventory was developed. This "preliminary" 2018 inventory was developed in late 2004 (Oct/Nov) and was designed solely for use in modeling sensitivity runs to provide a quick and dirty assessment of what "on the books" and "on the way" controls could be expected to provide in terms of improvements to visibility and regional haze impairment. A brief overview of the history of the three versions of the 2002 base year and the 2018 preliminary inventory use can be found at: http://www.vistas-sesarm.org/documents/STAD1204/2002and2018Emissions14Dec2004.ppt.

Following preparation of the final 3.1 version of the 2002 base year inventory, States were asked to review and provide comments on that inventory to MACTEC for update and revision. At the same time MACTEC prepared a revised draft version of the 2018 projection inventory (January 2005) and a draft version of a 2009 projection inventory (April 2005). All of these were known as version 3.1 and were provided to the VISTAS States for review and comment. Comments were received and updates to the inventories based on these comments were prepared. The revised inventories were provided to the VISTAS States. At that time to be consistent with the modeling nomenclature being used by AG in performing their modeling runs, the inventory became the Base F VISTAS inventory. The Base F inventory was delivered for review and comment in August of 2005. In addition, MACTEC delivered a report entitled *Documentation of the Revised 2002 Base Year, Revised 2018, and Initial 2009 Emission Inventories for VISTAS* on August 2, 2005 that described the methods used to develop the Base F inventories. For the Electric Generating Utilities (EGU) different versions of the Integrated Planning Model were used between Base D and Base F, resulting in different projections of future EGU emissions.

Over the period from August 2005 until June/July 2006 MACTEC received comments and updates to some categories from VISTAS States, particularly EGU. In addition, a new NONROAD model (NONROAD05) was released. Thus additional updates to the inventory were prepared based on the comments received along with revised NONROAD emission estimates from NONROAD05. The resultant inventory became the Base G inventory.

Following release of the Base G inventory in early 2007, four States specified additional changes to reflect their best estimates of EGU emission levels and controls in 2018. The resulting 2018 EGU emission inventory is referred to as Base G2, which was released in July 2007.

The current version of the VISTAS inventory is referred to as the "Best and Final (B&F)" inventory. States specified additional changes to the point source inventory to reflect improved knowledge of EGU emission levels and controls in 2009 and 2018. States also specified changes to nonEGU sources reflecting new information on anticipated controls and shutdowns. No changes to any other source sector (e.g., area, fire, nonroad, onroad) were made for the B&F inventory. The 2018 B&F inventory was released in October 2007, and the 2009 B&F inventory was released in December 2007.

This document details the development of the Base G/G2/B&F inventories for 2002, 2009 and 2018. The information that follows describes the development of the VISTAS inventory by sector from Base F forward. Unless specific updates were made to an inventory sector, the methods used for Base F were retained. Table I-1 through Table I-3 indicate roughly which version of the inventory is in use for each sector of the inventory as of the B&F inventory.

Under a separate contract, AG was asked to obtain and convert emission inventory data for the five states that make up the Midwest Regional Planning Organization (MRPO) for use by VISTAS/ASIP modelers. Details of this effort are documented in an Appendix to this report.

Table I-1 Inventory Version in Use by Year and Source Sector Through B&F - 2002

Source	AL	FL	GA	KY	MS	NC	SC	TN	VA	WV
EGU	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G
Non-EGU Point	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G	Base F with some source specific revisions in Base G
Area[1]	Base F for ammonia sources (CMU Model) and for some area sources, Base G for selected sources updated by the State with State supplied data	Base F except for some emissions zeroed out (and records removed) for some southern FL counties for Base G.	Base F	Base F	Base F	Base F for ammonia sources (CMU Model) and for some area sources, Base G for selected sources updated by the State with State supplied data. Some corrections applied by MACTEC to correct PM values	Base F	Base F	Base F for ammonia Sources (CMU Model) and for some area sources, Base G for selected sources updated by the State with State supplied data.	Base F
On-road	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G
Non-road	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources, except aircraft and locomotives updated for Base G.	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources except for aircraft in Cincinnati/N. KY Int. Airport, which are Base G.	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources	Base G for all sources included in the NONROAD model. NC moved from Southern to Mid-Atlantic State in seasonal adjustment file. Base F for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources, except for aircraft emissions which are Base G.	Base G for all sources included in the NONROAD model. Base F for non-NONROAD model sources
Fires	Base F Typical	Base F Typical	Base F Typical	Base F Typical	Base F Typical	Base F Typical	Base F Typical	Base F Typical	Base F Typical	Base F Typical

Notes:

Base G global Area Source changes that apply to ALL States: A) removal of Stage II refueling from area source file to non-road and on-road; B) modification of PM2.5 ratio for several fugitive dust sources per WRAP methodology; C) addition of portable fuel container (PFC) emissions to all States based on OTAQ report.

Table I-2 Inventory Version in Use by Year and Source Sector Through B&F - 2009

Source	AL	FL	GA	KY	MS	NC	SC	TN	VA	WV
EGU[1]	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final
Non-EGU Point[2]	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F
Area	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model. Some specific source categories updated using State supplied file to override projected values.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.
On-road	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G
Non-road	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources.	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources except for aircraft in Cincinnati/N. KY Int. Airport, which are Base G using State supplied growth factors.	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources
Fires	Base F typical except for Rx fires	Base F typical	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires

Notes:

1. All EGU emissions updated with new IPM runs in Base G; additional EGU-specific changes specified by States for Best & Final.
2. Revised growth factors from DOE AEO2006 fuel use projections

Table I-3 Inventory Version in Use by Year and Source Sector Through B&F - 2018

Source	AL	FL	GA	KY	MS	NC	SC	TN	VA	WV
EGU[1]	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final	Best & Final
Non-EGU Point[2]	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in Base G2 and B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in Base G2 and B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in Base G2 and B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in B&F	Base F methodology but with revised growth factors for fuel fired sources in Base G and source-specific changes in Base G2 and B&F
Area	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model. Some specific source categories updated using State supplied file to override projected values.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.	Base F with updated AEO growth factors for fuel fired sources. Agricultural ammonia sources from CMU model.
On-road	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G	Base G
Non-road	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources.	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources except for aircraft in Cincinnati/N. KY Int. Airport, which are Base G using State supplied growth factors.	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources	Base G for all sources included in the NONROAD model. Base F projection methodology used for non-NONROAD model sources
Fires	Base F typical except for Rx fires	Base F typical	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires	Base F typical except for Rx fires

Notes:

1. All EGU emissions updated with new IPM runs in Base G; additional EGU-specific changes specified by States for Base G2 and B&F.
2. Revised growth factors from DOE AEO2006 fuel use projections

1.0 2002 Base Year Inventory Development

1.1 Point Sources

This section details the development of the 2002 base year inventory for point sources. There were two major components to the development of the point source sector of the inventory. The first component was the incorporation of data submitted by the Visibility Improvement State and Tribal Association of he Southeast (VISTAS) States and local (S/L) agencies to the United States Environmental Protection Agency (EPA) as part of the Consolidated Emissions Reporting Rule (CERR) requirements Work on incorporating the CERR data into the revised base year involved: 1) obtaining the data from EPA or the S/L agency, 2) evaluating the emissions and pollutants reported in the CERR submittals, 3) augmenting CERR data with annual emission estimates for PM_{10}-PRI and $PM_{2.5}$-PRI; 4) evaluating the emissions from electric generating units, 5) completing quality assurance reviews for each component of the point source inventory, and 6) updating the database with corrections or new information from S/L agencies based on their review of the 2002 inventory. The processes used to perform those operations are described in the first portion of this section.

The second component was the development of a "typical" year inventory for electric generating units (EGUs). VISTAS determined that a typical year electric generating units (EGU) inventory was necessary to smooth out any anomalies in emissions from the EGU sector due to meteorology, economic, and outage factors in 2002. The typical year EGU inventory is intended to represent the five year (2000-2004) period that will be used to determine the regional haze reasonable progress goals. The second part of this section discusses the development of the typical year EGU inventory.

1.1.1 Development of 2002 Point Source Inventory

MACTEC developed a draft 2002 emission inventory in June 2004 (*Development of the Draft 2002 VISTAS Emission Inventory for Regional Haze Modeling – Point Sources*, MACTEC, June 18, 2004). The starting point for the draft 2002 emission inventory was EPA's 1999 National Emission Inventory (NEI), Version 2 Final (NEI99V2). For several states, we replaced the NEI99V2 data with more recent inventories for either calendar year 1999, 2000, or 2001 as submitted by the S/L agencies. We also performed several other updates, including updating emission estimates for selected large source of ammonia, incorporating 2002 Continuous Emissions Monitoring-(CEM)-based SO_2 and NO_x emissions for electric utilities, adding PM_{10} and $PM_{2.5}$ emissions when they were missing from an S/L submittal, and performing a variety of additional Quality assurance/Quality control (QA/QC) checks.

The next version of the 2002 inventory (referred to as Base F) was released in August 2005 (*Documentation of the Revised 2002 Base Year, Revised 2018, and Initial 2009 Emission Inventories for VISTAS*, MACTEC, August 2, 2005). The primary task in preparing the Base F 2002 base year inventory was the replacement of NEI99V2 data with data submitted by the VISTAS S/L agencies as part of the CERR submittal and included in EPA's 2002 NEI.

The next version of the 2002 inventory (referred to as Base G) was released in August 2006 and is documented in this report. The primary task in preparing the Base G 2002 base year inventory was the incorporation of corrections and new information as submitted by the S/L agencies based on their review of the Base F inventory. Note that no changes to the Base G 2002 point source inventory were made during the Base G2 and B&F update cycles (in other words, for the 2002 actual and typical inventories, Base G = Base G2 = B&F).

The following subsections document the data sources for the Base G/B&F inventory, the checks made on the CERR submittals, the process for augmenting the inventory with PM_{10} and $PM_{2.5}$ emissions, the evaluation of EGU emissions, other QA/QC checks, and other Base G updates. The final subsection summarizes the Base G/B&F 2002 inventory by state, pollutant, and sector (EGU and non-EGU).

1.1.1.1 Data Sources

Several data sources were used to compile the Base F point source inventory: 1) the inventories that the S/L submitted to EPA from May through July 2004 as required by the CERR; 2) supplemental data supplied by the S/L agencies that may have been revised or finalized after the CERR submittal to EPA, and 3) the draft VISTAS 2002 inventory in cases where S/L CERR data were not available. For the Base G inventory, we replaced data from Hamilton County, Tennessee, using data from Hamilton County's CERR submittal as contained in EPA's 2002 NEI inventory (in Base F, the inventory for Hamilton County was based on the draft VISTAS 2002 inventory, which in turn was based on the 1999 NEI).

Table 1.1-1 summarizes the data used as the starting point for the Base F 2002 inventory. Once all of the files were obtained, MACTEC ran the files through the EPA National Emission Inventory Format (NIF) Basic Format and Content checking tool to ensure that the files were submitted in standard NIF format and that there were no referential integrity issues with those files. In a couple of cases small errors were found. For example, in one case non-standard pollutant designations were used for particulate matter (PM) and ammonia emissions. MACTEC contacted each VISTAS State point source contact person to resolve the issues with the files and corrections were made. Once all corrections to the native files were made, MACTEC continued with the incorporation of the data into the VISTAS point source files. S/L agencies completed a detailed review of the Base F inventory. Additional updates and corrections to the Base F

inventory were requested by S/L agencies and incorporated into the Base G inventory. The Base G changes are documented in more detail in Section 1.1.1.6. No additional changes to the Base G inventory were made as part of the Base G2/B&F round of updates.

Table 1.1-1 State Data Submittals Used for the Base F 2002 Point Source Inventory.

State / Local Program	Point Source Emissions Data Source
AL	C
FL	B
GA	B
KY	C
MS	B
NC	C
SC	C
TN	C
VA	B
WV	B
Davidson County, TN	B
Hamilton County, TN	D
Memphis/Shelby County, TN	B
Knox County, TN	B
Jefferson County, AL	B
Jefferson County, KY	B
Buncombe County, NC	B
Forsyth County, NC	B
Mecklenburg County, NC	B

Key
A = Draft VISTAS 2002
B = CERR Submittal from EPA's file transfer protocol (FTP) site
C = Other (CERR or other submittal sent directly from S/L agency to MACTEC)
D = CERR Submittal from EPA's NEI 2002 Final Inventory

1.1.1.2 Initial Data Evaluation

For the Base F inventory, we conducted an initial review of the 2002 point source CERR data in accordance with the QA procedures specified in the Quality Assurance Project Plan (QAPP) for this project. The following evaluations were completed to identify potential data quality issues associated with the CERR data:

- Compared the number of sites in the CERR submittal to the number of sites in the VISTAS draft 2002 inventory; for all States, the number of sites in the CERR submittal was less than in the VISTAS draft 2002 inventory, since the CERR data was limited to major sources, while the VISTAS draft 2002 inventory contained data for both major and minor sources; verified with S/L contacts that minor sources not included in the CERR point source inventory were included in the CERR area source inventory.

- Checked for correct pollutant codes and corrected to make them NIF-compliant; for example, some S/L agencies reported ammonia emissions using the CAS Number or as "ammonia", rather than the NIF-compliant "NH_3" code.
- Checked for types of particulate matter codes reported (i.e., PM-FIL, PM-CON, PM-PRI, PM_{10}-PRI, PM10-FIL, $PM_{2.5}$-PRI, $PM_{2.5}$-FIL); corrected codes with obvious errors (i.e., changed PMPRI to PM-PRI). (The PM augmentation process for filling in missing PM pollutants is discussed later in Section 1.1.1.3)
- Converted all emission values that weren't in tons to tons to allow for preparation of emission summaries using consistent units.
- Checked start and end dates in the PE and EM tables to confirm consistency with the 2002 base year.
- Compared annual and daily emissions when daily emissions were reported; in some cases, the daily value was non-zero (but very small) but the annual value was zero. This was generally the result of rounding in an S/L agency's submittal.
- Compared ammonia emissions as reported in the CERR submittals and the 2002 Toxics Release Inventory; worked with S/L agencies to resolve any outstanding discrepancies.
- Compared SO_2 and NO_x emissions for EGUs to EPA's Clean Air Markets Division CEM database to identify any outstanding discrepancies. (A full discussion of the EGU emissions analysis is discussed later in Section 1.1.1.4)
- Prepared State-level emission summaries by pollutant for both the EGU and non-EGU sectors to allow S/L agencies to compare emissions as reported in the 1999 NEI Version 2, the VISTAS draft 2002 inventory, and the CERR submittals.
- Prepared facility-level emission summaries by pollutant to allow S/L agencies to review facility level emissions for reasonableness and accuracy.

We communicated the results of these analyses through email/telephone exchanges with the S/L point source contacts as well as through Excel summary spreadsheets. S/L agencies submitted corrections and updates as necessary to resolve any QA/QC issues from these checks.

1.1.1.3 PM Augmentation

Particulate matter emissions can be reported in many different forms, as follows:

PM Category	Description
PM-PRI	Primary PM (includes filterable and condensable)

PM-CON	Primary PM, condensable portion only (all less than 1 micron)
PM-FIL	Primary PM, filterable portion only
PM_{10}-PRI	Primary PM_{10} (includes filterable and condensable)
PM_{10}-FIL	Primary PM_{10} filterable portion only
$PM_{2.5}$ -PRI	Primary $PM_{2.5}$ (includes filterable and condensable)
$PM_{2.5}$ -FIL	Primary $PM_{2.5}$ filterable portion only

S/L agencies did not report PM emissions in a consistent manner. The State/local inventories submitted for VISTAS included emissions data for either PM-FIL, PM-PRI, PM_{10}-FIL, PM_{10}-PRI, $PM_{2.5}$ -FIL, $PM_{2.5}$ -PRI, and/or PM-CON. From any one of these pollutants, EPA has developed augmentation procedures to estimate PM_{10}-PRI, PM_{10}-FIL, $PM_{2.5}$ -PRI, $PM_{2.5}$ -FIL, and PM-CON. If not included in a State/local inventory, PM_{10}-PRI and $PM_{2.5}$ -PRI were calculated by adding PM_{10}-FIL and PM-CON or $PM_{2.5}$ -FIL and PM-CON, respectively.

The procedures for augmenting point source PM emissions are documented in detail in Appendix C of *Documentation for the Final 1999 National Emissions Inventory {Version 3} for Criteria Air Pollutants and Ammonia – Point Sources*, January 31, 2004). Briefly, the PM data augmentation procedure includes the following five steps:

- Step 1: Prepare S/L/T PM and PM_{10} Emissions for Input to the PM Calculator
- Step 2: Develop and Apply Source-Specific Conversion Factors
- Step 3: Prepare Factors from PM Calculator
- Step 4: Develop and Apply Algorithms to Estimate Emissions from S/L/T Inventory Data
- Step 5: Review Results and Update the NEI with Emission Estimates and Control Information.

Please refer to the EPA documentation for a complete description of the PM augmentation procedures.

Table 1.1-2 compares the original PM emission estimates from the S/L CERR submittals and the revised 2002 VISTAS emissions estimates calculated using the above methodology. This table is intended to show that we took whatever States provided in the way of PM and filled in gaps to add in PM-CON where emissions were missing in order to calculate PM_{10}-PRI and $PM_{2.5}$ -PRI for all processes to get a complete set of particulate data. We did not compare any other pollutants besides PM, since for other pollutants CERR emissions equal VISTAS emissions. As noted in Table 1.1-2, we made significant revisions to the PM emissions for Kentucky in the Base F inventory and for South Carolina in the Base G inventory.

Table 1.1-2 Comparison of Particulate Matter Emissions from the S/L Data Submittals and the Base G 2002 VISTAS Point Source Inventory

State	Database	PM-PRI	PM-FIL	PM-CON	PM_{10}-PRI	PM_{10}-FIL	$PM_{2.5}$ -PRI	$PM_{2.5}$ -FIL
AL	CERR	28,803	9,174	0	16,522	6,548	8,895	4,765
	VISTAS	43,368	33,336	10,129	32,791	22,661	23,290	13,328
FL	CERR	0	33,732	0	0	32,254	0	0
	VISTAS	61,728	37,325	24,403	57,243	32,840	46,147	21,744
GA	CERR	42,846	0	0	27,489	0	15,750	0
	VISTAS	44,835	37,088	7,799	33,202	25,403	22,777	15,085
KY	CERR	0	3,809	0	19,748	1,360	0	0
	VISTAS	27,719	22,349	5,329	21,326	15,963	14,173	8,749
MS	CERR	23,925	0	0	20,968	0	10,937	0
	VISTAS	23,928	17,632	6,296	21,089	14,793	11,044	5,739
NC	CERR	48,110	0	0	36,222	0	24,159	0
	VISTAS	48,114	41,407	6,708	36,992	30,284	27,512	21,113
SC	CERR	0	43,837	0	0	32,656	0	21,852
	VISTAS	43,844	38,633	5,210	34,799	29,588	26,418	21,207
TN	CERR	1,660	25,500	21,482	43,413	22,164	34,167	12,140
	VISTAS	56,797	32,085	24,715	50,937	26,269	41,442	16,774
VA	CERR	0	0	0	17,065	0	12,000	0
	VISTAS	40,856	36,414	4,442	17,065	12,623	12,771	8,607
WV	CERR	0	29,277	0	0	14,778	0	8445
	VISTAS	36,188	29,392	6,795	22,053	15,258	15,523	8,733

Note 1: CERR refers to data as submitted by S/L agencies; VISTAS refers to data calculated by MACTEC using the PM augmentation methodologies described in this document.

Note 2: KY DEP's initial CERR submittal reported particulate matter emissions using only PM-PRI pollutant code. MACTEC used this pollutant code during the initial PM augmentation routine. In February 2005, KY DEP indicated that data reported using the PM-PRI code should actually have been reported using the PM_{10}-PRI code. MACTEC performed a subsequent PM augmentation in April 2005 using the PM_{10}-PRI code. These changes were reflected in the Base F emission inventory.

Note 3: South Carolina Department of Health and Environmental Control (SC DHEC) initial CERR submittal reported particulate matter emissions using the PM-FIL, PM_{10}-FIL, and $PM_{2.5}$ -FIL pollutant codes. MACTEC used these pollutant codes during the initial PM augmentation routine. In August 2005, SC DHEC indicated that data reported using the PM-FIL, PM_{10}-FIL, and $PM_{2.5}$ -FIL pollutant codes should actually have been reported using the PM-PRI, PM_{10}-PRI, and $PM_{2.5}$ _PRI codes. MACTEC performed a subsequent PM augmentation in April 2006 using the revised pollutant codes. These changes were reflected in the Base G emission inventory.

Note 4: The emission values in the VISTAS emission rows above differ slightly from the final values in the Base G inventory. This is due to several corrections and updates to the 2002 inventory submitted by S/L agencies after the PM augmentation was performed as discussed in Section 1.1.1.6.

After the PM augmentation process was performed, we executed a series of checks to identify potential inconsistencies in the PM inventory. These checks included:

- PM-PRI less than PM_{10}-PRI, $PM_{2.5}$ -PRI, PM_{10}-FIL, $PM_{2.5}$ -FIL, or PM-CON;
- PM-FIL less than PM_{10}-FIL, $PM_{2.5}$ -FIL;
- PM_{10}-PRI less than $PM_{2.5}$ -PRI, PM_{10}-FIL, $PM_{2.5}$ -FIL or PM-CON;
- PM_{10}-FIL less than $PM_{2.5}$ -FIL;
- PM25-PRI less than $PM_{2.5}$ -FIL or PM-CON;
- The sum of PM_{10}-FIL and PM-CON not equal to PM_{10}-PRI; and
- The sum of $PM_{2.5}$ -FIL and PM-CON not equal to $PM_{2.5}$ -PRI.

S/L agencies were asked to review this information and provide corrections where the inconsistencies were significant. In general, corrections (or general directions) were provided in the case of the potential inconsistency issues. In other cases, the agency provided specific process level pollutant corrections.

Note that for the Base G inventory, only the PM_{10}-PRI and $PM_{2.5}$ -PRI emission estimates were retained since they are the only two PM species that are included in the air quality modeling. Other PM species were removed from the Base G inventory to facilitate emissions modeling.

1.1.1.4 EGU Analysis

We made a comparison of the annual SO_2 and NO_x emissions for EGUs as reported in the S/L agencies CERR submittals and EPA's Clean Air Markets Division (CAMD) CEM database to identify any outstanding discrepancies. Facilities report hourly CEM data to EPA for units that are subject to CEM reporting requirements of the NO_x State Implementation Plan (SIP) Call rule and Title IV of the Clean Air Act (CAA). EPA sums the hourly CEM emissions to the annual level, and we compared these annual CEM emissions to those in the S/L inventories. The 2002 CEM inventory containing NO_x and SO_2 emissions and heat input data were downloaded from the EPA CAMD web site (www.epa.gov/airmarkets).

The first step in the EGU analysis involved preparing a crosswalk file to match facilities and units in the CAMD inventory to facilities and units in the S/L inventories. In the CAMD inventory, the Office of Regulatory Information Systems (ORIS) identification (ID) code identifies unique facilities and the unit ID identifies unique boilers and internal combustion engines (i.e., turbines and reciprocating engines). In the S/L inventories, the State and county FIPS and State facility ID together identify unique facilities and the emission unit ID identifies unique boilers or internal combustion engines. In most cases, there is a one-to-one correspondence between the CAMD identifiers and the S/L identifiers. However, in some of the S/L inventories, the emissions for multiple emission units are summed and reported under one emission unit ID. We created an Excel spreadsheet that contained an initial crosswalk with the ORIS ID and unit ID in the CEM inventory matched to the State and county Federal

Implementation Plan (FIPS), State facility ID, and emission unit ID in the S/L inventory. The initial crosswalk contained both the annual emissions summed from the CAMD database as well as the S/L emission estimate. It should be noted that the initial matching of the IDs in both inventories was based on previous crosswalks that had been developed for the preliminary VISTAS 2002 inventory and in-house information compiled by MACTEC and Alpine Geophysics. The matching at the facility level was nearly complete. In some cases, however, S/L agency or stakeholder assistance was needed to match some of the CEM units to emission units in the S/L inventories.

The second step in the EGU analysis was to prepare an Excel spreadsheet that compared the annual emissions from the hourly CAMD inventory to the annual emissions reported in the S/L inventory. The facility-level comparison of CEM to emission inventory NO_x and SO_2 emissions found that for most facilities, the annual emissions from the S/L inventory equaled the CAMD CEM emissions. Minor differences could be explained because the facility in the S/L inventory contained additional small or emergency units that were not included in the CAMD database.

The final step was to compare the SO_2 and NO_x emissions for select Southern Company units in the VISTAS region. Southern Company is a super-regional company that owns EGUs in four VISTAS States – Alabama, Florida, Georgia, and Mississippi – and participates in VISTAS as an industry stakeholder. Southern Company independently provided emission estimates for 2002 as part of the development of the preliminary VISTAS 2002 inventory. In most cases, these estimates were reviewed by the States and incorporated into the States CERR submittal. The exception to this was a decision made by Georgia's Department of Environmental Protection (GDEP) to utilize CEM-based emissions for the actual 2002 emissions inventory for sources within the State when Southern Company also provided data. There were no major inconsistencies between the Southern Company data, the CAMD data, and the S/L CERR data.

The minor inconsistencies included small differences (<2 percent) in emission estimates, exclusion/inclusion of small gas-fired units in the different databases, and grouping of emission units in S/L CERR submittals where CAMD listed each unit individually. We compared SO_2 and NO_x emissions on a unit by unit basis and did not find any major inconsistencies.

1.1.1.5 QA Review of Base F Inventory

QA checks were run on the Base F point source inventory data set to ensure that all corrections provided by the S/L agencies and stakeholders were correctly incorporated into the S/L inventories and that there were no remaining QA issues. After exporting the inventory to ASCII text files in NIF 3.0, the EPA QA program was run on the ASCII files and the QA output was reviewed to verify that all QA issues that could be addressed were resolved.

Throughout the inventory development process, QA steps were performed to ensure that no double counting of emissions occurred, and to ensure that a full and complete inventory was developed for VISTAS. QA was an important component to the inventory development process and MACTEC performed the following QA steps on the point source component of the VISTAS revised 2002 base year inventory:

1. Facility level emission summaries were prepared and evaluated to ensure that emissions were consistent and that there were no missing sources.
2. State-level EGU and non-EGU comparisons (by pollutant) were developed between the Base F 2002 base year inventory, the draft VISTAS 2002 inventory, and the 1999 NEI Version 2 inventory.
3. Data product summaries and raw NIF 3.0 data files were provided to the VISTAS Emission Inventory Technical Advisor and to the Point Source, EGU, and non-EGU Special Interest Work Group representatives for review and comment. Changes based on these comments were reviewed and approved by the S/L point source contact prior to implementing the changes in the files.
4. Version numbering was used for all inventory files developed. The version numbering process used a decimal system to track major and minor changes. For example, a major change would result in a version going from Base F1 to Base F2.

1.1.1.6 Additional Base G Updates and Corrections

S/L agencies completed a detailed review of the Base F inventory. Table 1.1-3 summarizes the updates and corrections to the Base F inventory that were requested by S/L agencies and incorporated into the Base G inventory.

There was a discrepancy between the base year 2002 and 2009/2018 emissions for PM_{10}-PRI, $PM_{2.5}$-PRI, and NH_3. The 2002 emissions were provided directly by the S/L agencies and were estimated using a variety of techniques (i.e., EPA emission factors, S/L emission factors, site-specific emission factors, and source test data). The 2009/2018 emissions, on the other hand, were estimated by Pechan (see Section 2.1.1.3) using an emission factor file based solely on AP-42 emission factors. An adjustment was made for 2002 EGU PM and NH_3 emissions to reconcile these differences. The post-processed Integrated Planning Model® (IPM®) 2009/2018 output uses a set of PM and NH_3 emission factors that are "the most recent EPA approved uncontrolled emission factors" – these are most likely not the same emission factors used by States and emission inventory preparation contractors for estimating these emissions in 2002 for EGUs in the VISTAS domain. VISTAS performed a set of modifications to replace 2002 base year PM and NH_3 emission estimates with estimates derived from the most recent EPA-approved emission factors. For further details of the methodology used to make this adjustment, see *EGU Emission Factors and Emission Factor Assignment,* memorandum from Greg Stella to VISTAS State Point Source Contacts and VISTAS EGU Special Interest Workgroup, June 13, 2005.

Table 1.1-3 Summary of Updates and Corrections to the Base F 2002 Inventory Incorporated into the 2002 Base G Inventory.

Affected State(s)	Nature of Update/Correction
TN, WV	The latitude and longitude values for TN (except the four local programs) and WV were truncated to two decimal places in the Base F inventory. MACTEC re-exported the NIF ER tables in a manner that so that the latitude and longitude were not truncated in the Base G inventory.
AL	Corrected the latitude and longitude for two facilities: Ergon Terminalling (Site ID: 01-073-010730167) and Southern Power Franklin (Site ID: 01-081-0036).
	Corrections to stack parameters at 10 facilities for stacks with parameters that do not appear to fall into the ranges typically termed "acceptable" for AQ modeling.
FL	Corrected emission values for the Miami Dade RRF facility (Site ID: 12-086-0250348).
GA	Hercules Incorporated (12-051-05100005) had an erroneous process id (#3) within emission unit id SB9 and was deleted. This removes about 6,000 tons of SO_2 from the 2002 inventory.
	Provided a revised file of location coordinates at the stack level that was used to replace the location coordinated in the ER file.
NC	Made several changes to Base F inventory to correct the following errors: 1. Corrected emissions at Hooker Furniture (Site ID: 37-081-08100910), release point G-29, 9211.38 tons volatile organic compounds (VOC's) should be 212.2 tons, 529.58 tons PM_{10} should be 17.02 tons, 529.58 tons PM2.5 should be 15.79 tons in 2002 inventory. 2. Identified many stack parameters in the ER file that were unrealistic. Several have zero for height, diameter, gas velocity, and flow rate. NC used the procedures outlined in Section 8 of the document ""National Emission Inventory QA and Augmentation Report" to correct unrealistic stack parameters. 3. Identified truncated latitude and longitude values in Base F inventory. NC updated all Title V facility latitude and longitude that was submitted to EPA for those facilities in 2004. Smaller facilities with only two decimal places were not corrected. 4. Corrected emissions for International Paper (3709700045) Emission Unit ID, G-12, should be 1.8844 tons VOCs instead of 2819.19 tons in 2002
SC	Corrected PM species emission values. SC DHEC's initial CERR submittal reported particulate matter emissions using the PM-FIL, PM_{10}-FIL, and PM25-FIL pollutant codes. In August 2005, SC DHEC indicated that data reported using the PM-FIL, PM_{10}-FIL, and PM25-FIL pollutant codes should actually have been reported using the PM-PRI, PM_{10}-PRI, and PM25_PRI codes. MACTEC performed a subsequent PM augmentation in April 2006 using the revised pollutant codes. These changes were reflected in the Base G emission inventory.
TN	Identified six facilities that closed in 2000/2001 but had non-zero emissions in the 2002 Base F inventory. MACTEC changed emissions to zero for all pollutants in the Base G 2002 inventory.
	Supplied updated emission inventory for the Bowater facility (47-107-0012) based on the facility's updated 2002 emission inventory update.
	Replaced data from Hamilton County, Tennessee, using data from Hamilton County's CERR submittal as contained in EPA's 2002 NEI (in Base F, the inventory for Hamilton County was based on the draft VISTAS 2002 inventory, which in turn was based on the 1999 NEI).
	Updated emissions for PCS Nitrogen Fertilizer LP (Site ID: 47-157-00146)
WV	Updated emissions for Steel of West Virginia (Site ID: 54-011-0009)
	Made changes to several Site ID names due to changes in ownership
	Made corrections to latitude/longitude and stack parameters at a few facilities for stacks with parameters that do not appear to fall into the ranges typically termed "acceptable" for AQ modeling.

1.1.1.7 Summary of B&F 2002 Inventory

Tables 1.1-4 through 1.1-10 summarize the B&F 2002 base year inventory. All values are in tons. Note that no changes to the Base G 2002 point source inventory were made during the Base G2 and B&F update cycles (in other words, Base G = Base G2 = B&F)

For the purposes of Tables 1.1-4 through 1.1-10, EGU emissions include the emissions from all processes with a Source Classification Code (SCC) of either 1-01-xxx-xx (External Combustion Boilers – Electric Generation) or 2-01-xxx-xx (Internal Combustion Engines – Electric Generation). Emissions for all other SCCs are included in the non-EGU column. Note that aggregating emissions into EGU and non-EGU sectors based on the above SCCs causes a minor inconsistency with the EGU emissions reported in EPA's CAMD database. The EGU emissions summarized in these tables may include emissions from some smaller electric generating units in the VISTAS inventory that are not in CAMD's 2002 CEM database or the IPM forecasted emissions. The minor inconsistencies result in a less than 2 percent difference between the summary tables below and the data from CAMD's CEM database.

Table 1.1-4 Base G / B&F 2002 VISTAS Point Source Inventory for SO_2 (tons/year).

State	All Point Sources	EGUs	Non-EGUs
AL	544,309	447,828	96,481
FL	518,721	453,631	65,090
GA	568,731	514,952	53,778
KY	518,086	484,057	34,029
MS	103,388	67,429	35,960
NC	522,113	477,990	44,123
SC	259,916	206,399	53,518
TN	413,755	334,151	79,604
VA	305,106	241,204	63,903
WV	570,153	516,084	54,070
Total	**4,324,278**	**3,743,725**	**580,556**

Note: EGU emissions include SCCs 1-01-xxx-xx and 2-01-xxx-xx; non-EGU has all other SCCs.

Table 1.1-5 Base G / B&F 2002 VISTAS Point Source Inventory for NO_x (tons/year).

State	All Point Sources	EGUs	Non-EGUs
AL	244,348	161,038	83,310
FL	302,834	257,677	45,156
GA	196,767	147,517	49,251
KY	237,209	198,817	38,392
MS	104,661	43,135	61,526
NC	196,782	151,854	44,928
SC	130,394	88,241	42,153
TN	221,652	157,307	64,344
VA	147,300	86,886	60,415
WV	277,589	230,977	46,612
Total	**2,059,536**	**1,523,449**	**536,087**

Note: EGU emissions include SCCs 1-01-xxx-xx and 2-01-xxx-xx; non-EGU has all other SCCs.

Table 1.1-6 Base G / B&F 2002 VISTAS Point Source Inventory for VOC (tons/year).

State	All Point Sources	EGUs	Non-EGUs
AL	49,332	2,295	47,037
FL	40,995	2,524	38,471
GA	34,952	1,244	33,709
KY	46,321	1,487	44,834
MS	43,852	648	43,204
NC	62,170	988	61,182
SC	38,927	470	38,458
TN	85,254	926	84,328
VA	43,906	754	43,152
WV	15,775	1,180	14,595
Total	**461,484**	**12,516**	**448,970**

Note: EGU emissions include SCCs 1-01-xxx-xx and 2-01-xxx-xx; non-EGU has all other SCCs.

Table 1.1-7 Base G / B&F 2002 VISTAS Point Source Inventory for CO (tons/year).

State	All Point Sources	EGUs	Non-EGUs
AL	185,550	11,279	174,271
FL	139,045	57,113	81,933
GA	140,561	9,712	130,850
KY	122,555	12,619	109,936
MS	59,871	5,303	54,568
NC	64,461	13,885	50,576
SC	63,305	6,990	56,315
TN	122,348	7,084	115,264
VA	70,688	6,892	63,796
WV	100,220	10,341	89,879
Total	**1,068,604**	**141,218**	**927,388**

Note: EGU emissions include SCCs 1-01-xxx-xx and 2-01-xxx-xx; non-EGU has all other SCCs.

Table 1.1-8 Base G / B&F 2002 VISTAS Point Source Inventory for PM_{10}-PRI (tons/year).

State	All Point Sources	EGUs	Non-EGUs
AL	32,886	7,646	25,240
FL	57,243	21,387	35,857
GA	32,834	11,224	21,610
KY	21,326	4,701	16,626
MS	21,106	1,633	19,472
NC	36,592	22,754	13,838
SC	35,542	21,400	14,142
TN	49,814	14,640	35,174
VA	17,211	3,960	13,252
WV	22,076	4,573	17,503
Total	**326,630**	**113,918**	**212,714**

Note: EGU emissions include SCCs 1-01-xxx-xx and 2-01-xxx-xx; non-EGU has all other SCCs.

Table 1.1-9 Base G / B&F 2002 VISTAS Point Source Inventory for $PM_{2.5}$ -PRI (tons/year).

State	All Point Sources	EGUs	Non-EGUs
AL	23,291	4,113	19,178
FL	46,148	15,643	30,504
GA	22,401	4,939	17,462
KY	14,173	2,802	11,372
MS	11,044	1,138	9,906
NC	26,998	16,498	10,500
SC	27,399	17,154	10,245
TN	39,973	12,166	27,807
VA	12,771	2,606	10,165
WV	15,523	2,210	13,313
Total	**239,721**	**79,269**	**160,452**

Note: EGU emissions include SCCs 1-01-xxx-xx and 2-01-xxx-xx; non-EGU has all other SCCs.

Table 1.1-10 Base G / B&F 2002 VISTAS Point Source Inventory for NH_3 (tons/year).

State	All Point Sources	EGUs	Non-EGUs
AL	2,200	317	1,883
FL	1,657	234	1,423
GA	3,697	83	3,613
KY	1,000	326	674
MS	1,359	190	1,169
NC	1,234	54	1,180
SC	1,553	142	1,411
TN	1,817	204	1,613
VA	3,230	127	3,104
WV	453	121	332
Total	**18,200**	**1,798**	**16,402**

Note: EGU emissions include SCCs 1-01-xxx-xx and 2-01-xxx-xx; non-EGU has all other SCCs.

1.1.2 Development of Typical Year EGU inventory

VISTAS developed a typical year 2002 emission inventory for EGUs to avoid anomalies in emissions due to variability in meteorology, economic, and outage factors in 2002. The typical year inventory represents the five year (2000-2004) period and was used to determine the regional haze reasonable progress goals. Actual 2002 emissions were used when comparing the CMAQ modeling results to the 2002 measurements in the model performance evaluation. A detailed discussion of how the actual and typical year EGU inventories were used for modeling is contained in the *Technical Support Document for VISTAS Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans* located on the VISTAS web site (http://www.vistas-sesarm.org)

Data from EPA's CAMD were used to develop normalization factors for producing a 2002 typical year inventory for EGUs. We used the ratio of the 2000-2004 average heat input and the 2002 actual heat input to normalize the 2002 actual emissions. MACTEC obtained data from EPA's CAMD for utilities regulated by the Acid Rain program. Annual data for the period 2000 to 2004 were obtained from the CAMD web site (www.epa.gov/airmarkets). The parameters available were the SO_2 and NO_x emission rates, heat input, and operating hours. We used the actual 2002 heat input and the average heat input for the 5-year period from 2000-2004 as the normalization factor, as follows:

$$\text{Normalization Factor:} \quad \frac{\text{2000-2004 average heat input}}{\text{2002 actual heat input}}$$

If the unit did not operate for all five years, then the 2000-2004 average heat input was calculated for the one or two years in which the unit did operate. For example, if the unit operated only during 2002, then the normalization factor would be 1.0. The annual actual emissions were multiplied by the normalization factor to determine the typical emissions for 2002, as follows:

$$\text{Typical Emissions} = \text{2002 actual emissions} \times \text{Normalization Factor}$$

After applying the normalization factor, some adjustments were needed for special circumstances. For example, a unit may not have operated in 2002 and thus have zero emissions. If the unit had been permanently retired prior to 2002, then we used zero emissions for the typical year. If the unit had not been permanently retired and would normally operate in a typical year, then we used the 2001 (or 2000) heat input and emission rate to calculate the typical year emissions.

The Southern Company provided typical year data for their sources. Hourly emissions data for criteria pollutants were provided. MACTEC aggregated the hourly emissions into annual values. Further documentation of how Southern Company created the typical year inventory for their

units can be found in *Developing Southern Company Emissions and Flue Gas Characteristics for VISTAS Regional Haze Modeling (April 2005, presented at 14th International Emission Inventory Conference* http://www.epa.gov/ttn/chief/conference/ei14/session9/kandasamy.pdf). Since Southern Company only supplied filterable particulate emissions, we ran the $PM_{10}/PM_{2.5}$ augmentation routine to calculate annual emission estimates for PM_{10}-PRI and $PM_{2.5}$-PRI. The Southern Company typical year data were used for Southern Company sources in Alabama, Florida, and Mississippi. Georgia EPD elected to use the typical year normalization factor derived from the CAMD data instead of the Southern Company typical year data (as was used in the Base F inventory).

The final step was to replace the 2002 actual emissions with the 2002 typical year data described above. MACTEC provided the raw data and results of the typical year calculations in a spreadsheet for S/L agency review and comment. Any comments made were incorporated into the Base G inventory.

Table 1.1-11 summarizes emissions by State and pollutant for the actual 2002 EGU inventory and the typical year EGU inventory. For the entire VISTAS region, actual 2002 SO_2 emissions were about 1.6 percent higher than the typical year emissions. The differences on a state-be-state basis ranged from actual emissions being 2.3 percent lower in Kentucky to 10.9 percent higher in Mississippi. For the entire VISTAS region, actual 2002 NO_x emissions were about 1.7 percent lower than the typical year emissions. The differences on a state-be-state basis ranged from actual emissions being 1.6 percent lower in Kentucky to 6.3 percent higher in Mississippi.

Table 1.1-11 Comparison of SO_2 and NO_x Emissions (tons/year) for EGUs.

	SO_2 Emissions (tons/year)			NO_x Emissions (tons/year)		
State	**Actual 2002**	**Typical 2002**	**Percentage Difference**	**Actual 2002**	**Typical 2002**	**Percentage Difference**
AL	447,828	423,736	5.4	161,038	154,704	3.9
FL	453,631	444,383	2.0	257,677	255,678	0.8
GA	514,952	517,633	-0.5	147,517	148,126	-0.4
KY	484,057	495,153	-2.3	198,817	201,928	-1.6
MS	67,429	60,086	10.9	43,135	40,433	6.3
NC	477,990	478,489	-0.1	151,854	148,812	2.0
SC	206,399	210,272	-1.9	88,241	88,528	-0.3
TN	334,151	320,146	4.2	157,307	152,137	3.3
VA	241,204	233,691	3.1	86,886	85,081	2.1
WV	516,084	500,381	3.0	230,977	222,437	3.7
Total	**3,743,725**	**3,683,968**	**1.6**	**1,523,449**	**1,497,864**	**1.7**

Note: a negative percentage difference indicates actual emissions are less than the typical year emissions.

1.2 Area Sources

This section details the development of the Base G 2002 base year inventory for area sources. There are three major components of the area source sector of the inventory. The first component is the "typical" year fire inventory. Version 3.1 of the VISTAS base year fire inventory provided actual 2002 emissions estimates. Since fire emissions are not easily grown or projected, in order to effectively represent fires in both the base and future year inventories, VISTAS determined that a typical year fire inventory was necessary. Development of the "typical" year fire inventory covered wildfire, prescribed burning, agricultural fires and land clearing fires. The first part of this section of the report discusses the development of the typical year fire inventory. The methodology provided in that section is identical to the documentation provided for Base F since the "typical" year inventory was developed as part of the Base F development effort. The major change in Base G for the fire component of the inventory was the development of projection year inventories that represent alternatives to the "typical" year inventory. These alternative projections incorporated projected changes in the acreage burned for prescribed fires on Federal lands. These projections are an augmentation of the "typical" year inventory.

The second component of the area source inventory was the incorporation of data submitted by the VISTAS States to the United States Environmental Protection Agency (EPA) as part of the CERR. Work on incorporating the CERR data into the revised base year involved: 1) obtaining the data from EPA, 2) evaluating the emissions and pollutants reported in order to avoid double counting and 3) backfilling from the existing VISTAS 2002 base year inventory for missing sources/pollutants. The processes used to perform those operations are described in the second portion of this section. That work was performed as part of the Base F inventory effort. In general no changes to that method were made as part of the Base G inventory updates. The methods used for the Base F inventory development effort using the CERR submittals have been maintained in this document. Where necessary, additional documentation has been added to 1) reflect changes that resulted from VISTAS States review of the Base F inventory and the incorporation of those changes into Base G, 2) changes made to how certain sources were estimated or 3) addition of new sources not found in Base F.

The final component of the area source inventory was related to the development of NH_3 emission estimates for livestock and fertilizers and paved road PM emissions. For the NH_3 emission estimates for livestock and fertilizers we used version 3.6 of the Carnegie Mellon University (CMU) NH_3 model. For the paved road PM emissions, we used the most recent estimates developed by EPA as part of the National Emission Inventory (NEI) development effort. EPA had developed an improved methodology for estimating paved road emissions so those values were substituted directly into the inventory after receiving consensus from all of the VISTAS States to perform the replacement. Details on these methods are provided in the third

portion of this section of the document. That section is virtually identical to that from the Base F inventory document as there were only a couple of changes to the ammonia portion of the inventory and some updates to all fugitive dust categories including paved roads on a global basis between Base F and Base G.

Finally, quality assurance steps for each component of the area source inventory are discussed.

1.2.1 Development of a "typical" year fire inventory

Typical year fire emissions were developed starting from the actual fire acreage data and emission calculated for each VISTAS State. The table below shows the data submitted by each State in the VISTAS region indicating what data was received from each State for the purposes of calculating actual fire emissions.

Fire Type	AL	FL	GA	KY	MS	NC	SC	TN	VA	WV
Land Clearing	✓	✓	✓				✓			
Ag Burning	✓	✓	✓				✓			
Wildfires	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Prescribed	✓	✓	✓	✓	✓	✓	✓	✓		✓

In order to effectively characterize fire emissions in the VISTAS region, a typical (as opposed to strictly 2002 year based inventory) was required. Development of a typical year fire inventory provided the capability of using a comparable data set for both the base year and future years. Thus fire emissions would remain the same for air quality and visibility modeling in both the base and any future years. MACTEC originally proposed five different methods for developing the typical fire year to the VISTAS Fire Special Interest Work Group (SIWG) and requested their feedback and preference for developing the final typical year inventory. The method that was selected by SIWG members was to use a method similar to that used to develop an early version of a 2018 projection inventory. For that early 2018 inventory, State level ratios of acres over a longer term record (three or more years) developed for each fire type relative to 2002. The 2002 acreage was then scaled up or down based on these ratios to develop a typical year inventory. For Base F and G, the decision of the VISTAS Fire SIWG was to base the ratio on county level data for States that supplied long term fire-by-fire acreage data rather than State-level ratios. Where States did not supply long term fire-by-fire acreage data, MACTEC reverted to using State-level ratios. With one broad exception (wildfires) this method was implemented for all fires. MACTEC solicited long term fire-by-fire acreage data by fire type from each VISTAS State. A minimum of three or more years of data were used to develop the ratios. Those

data were then used to develop a ratio for each county based on the number of acres burned in each county for each fire type relative to 2002.

Thus if we had long term county prescribed fire data from a State, we developed a county acreage ratio of:

$$Ratio = \frac{\text{Long term average county level Rx acres}}{\text{2002 actual county level Rx acreage}}$$

This ratio was then multiplied times the actual 2002 acreage to get a typical value (basically the long term average county level acres). Wherever possible this calculation was performed on a fire by fire basis. The acreage calculated using the ratio was then used with the fuel loading and emission factor values that we already had (and had been reviewed by the SIWG) to calculate emissions using the same method used for the 2002 actual values (which were previously documented). The following lists indicate which counties used the State ratios by fire type.

Land Clearing		Agricultural Fires		Prescribed Burning	
FIPS	**COUNTY**	**FIPS**	**COUNTY**	**FIPS**	**COUNTY**
12086	Miami-Dade County	13063	Clayton County	13059	Clarke County
12037	Franklin County	13083	Dade County	13083	Dade County
12043	Glades County	13089	Dekalb County	13089	Dekalb County
12045	Gulf County	13097	Douglas County	13097	Douglas County
12049	Hardee County	13121	Fulton County	13121	Fulton County
12057	Hillsborough County	13135	Gwinnett County	13123	Gilmer County
12073	Leon County	13137	Habersham County	13135	Gwinnett County
12077	Liberty County	13215	Muscogee County	13139	Hall County
12081	Manatee County	13227	Pickens County	13215	Muscogee County
12095	Orange County	13241	Rabun County	13241	Rabun County
12097	Osceola County	13247	Rockdale County	13247	Rockdale County
12103	Pinellas County	13311	White County		
12115	Sarasota County				
13015	Bartow County				
13021	Bibb County				
13045	Carroll County				
13047	Catoosa County				
13057	Cherokee County				
13059	Clarke County				
13063	Clayton County				
13073	Columbia County				
13077	Coweta County				
13083	Dade County				
13089	Dekalb County				
13097	Douglas County				
13117	Forsyth County				
13121	Fulton County				
13129	Gordon County				
13135	Gwinnett County				
13137	Habersham County				
13143	Haralson County				
13147	Hart County				

Land Clearing		Agricultural Fires		Prescribed Burning	
FIPS	COUNTY	FIPS	COUNTY	FIPS	COUNTY
13151	Henry County				
13169	Jones County				
13215	Muscogee County				
13237	Putnam County				
13241	Rabun County				
13291	Union County				
13311	White County				

There were three exceptions to this method.

Exception 1: Use of State Ratios for Wildfires

The first exception was that wildfires estimates were developed using State ratios rather than county ratios. This change was made after initial quality assurance of the draft estimates revealed that some counties were showing unrealistic values created by very short term data records or missing data that created unrealistic ratios. In addition, exceptionally large and small fires were removed from the database since they were felt to be atypical. For example the Blackjack Complex fire in Georgia was removed from the dataset because the number of acres burned was "atypical" in that fire. We also removed all fires less than 0.1 acres from the dataset.

Exception 2: Correction for Blackened Acres on Forest Service Lands

Following discussions with the United States Forest Service (Forest Service) (memo from Cindy Huber and Bill Jackson, dated August 13, 2004), it was determined that the acres submitted by the Forest Service for wildfires and prescribed fires represented perimeter acres rather than "blackened" acres. Thus for wildfires and prescribed fires on Forest Service lands, a further correction was implemented to correct the perimeter acre values to blackened acres. The correction was made based on the size of the fire. For prescribed fires over 100 acres in size the acreage was adjusted to be 80 percent of the initial reported value. For prescribed fires of 100 acres or less the acreage values were maintained as reported. For wildfires, all reported acreage values were adjusted to be 66 percent of their initially reported values. These changes were made to all values reported for Forest Service managed lands.

Exception 3: Missing/Non-reported data

When we did not receive data from a VISTAS State for a particular fire type, a composite average for the entire VISTAS region was used to determine the typical value for that type fire. For example, if no agricultural burning long term acreage data was reported for a particular State, MACTEC determined an overall VISTAS regional average ratio that was used to multiply

times the 2002 values to produce the "typical" values. This technique was applied to all fire types when data was missing.

In addition, for wildfires and prescribed burning, ratios were developed for "northern" and "southern" tier States within the VISTAS region and those ratios were applied to each State with missing data depending upon whether they were considered a "northern" or "southern" tier State. Development of "southern" and "northern" tier data was an attempt to account for a change from a predominantly pine/evergreen ecosystem (southern) to a pine/deciduous ecosystem (northern). States classified as "southern" included: AL, FL, GA, MS, and SC. States classified as "northern" included: KY, NC, TN, VA, and WV.

Finally for land clearing and agricultural fires, there are no NH_3 and SO_2 emissions. This is due to the lack of emission factors for these pollutants for these fire types.

Table 1.2-1 shows fire emissions from the original base year emission inventory (VISTAS 3.1), the actual 2002 emissions and the typical year emissions for the entire VISTAS region. The actual 2002 and typical fire emissions represent the Base F and Base G 2002 emissions. The typical emissions also represent the 2009 and 2018 emissions for all fire types with the exception of prescribed burning. Revisions made to the typical year prescribed fire emissions for 2009 and 2018 are detailed in the projection section. Also, State level Base G emissions from fires for all years can be found in the tables in Appendix A. Values for fires in those tables are "typical" year values.

Figures 1.2-1 through 1.2-4 show the State by State changes in emissions between the original 2002 base year fire inventories, the actual 2002 and the typical year inventories for carbon monoxide (CO) by fire type. Due to the relative magnitude of CO emissions compared to other criteria and PM pollutants from fires; this pollutant is normally chosen to represent the distribution of fires in the example plots.

Table 1.2-1 Emissions from Fires in the VISTAS Region – Comparison between Original Base Year 2002 (VISTAS 3.1), 2002 Actual and Typical Year Base G Emissions.

		CO	NH_3	NO_X	PM_{10}-FIL	PM_{10}-PRI	$PM_{2.5}$-FIL	$PM_{2.5}$-PRI	SO_2	VOC
Total LC	Actual (Base G)	492,409	0	14,568	62,146	62,146	62,146	62,146	0	33,799
	Typical (Base G)	675,838	0	19,995	80,598	80,598	80,598	80,598	0	46,389
	VISTAS 3.1	484,240	0	14,327	61,325	61,325	61,325	61,325	0	33,238
Total Ag	Actual (Base G)	164,273	0	903	30,958	30,958	30,385	30,385	0	21,946
	Typical (Base G)	161,667	0	903	30,465	30,465	29,892	29,892	0	21,595
	VISTAS 3.1	331,073	0	903	41,480	41,480	40,192	40,192	0	41,875
Total WF	Actual (Base G)	298,835	1,333	6,628	28,923	28,923	24,926	24,926	1,611	16,804
	Typical (Base G)	547,174	2,451	11,955	53,070	53,070	45,635	45,635	3,072	28,491
	VISTAS 3.1	275,766	1,230	6,133	26,680	26,680	23,002	23,002	1,476	15,718
Total RX	Actual (Base G)	1,678,216	7,616	36,561	168,938	168,938	145,175	145,175	9,839	78,988
	Typical (Base G)	1,635,776	7,425	35,650	164,811	164,811	141,636	141,636	9,590	76,990
	VISTAS 3.1	1,724,940	7,822	37,556	173,590	173,590	149,181	149,181	10,101	81,188

Key: LC = Land Clearing; Ag = Agricultural burning; WF = wildfires; RX = prescribed burning. Actual and Typical represent Base F and Base G (e.g., no change in methodology for Base F and Base G) for 2002.

Figure 1.2-1 CO Emissions from Agricultural Burning for the Original Base Year, 2002 Actual Base G, and 2002 Typical Base G Inventories.

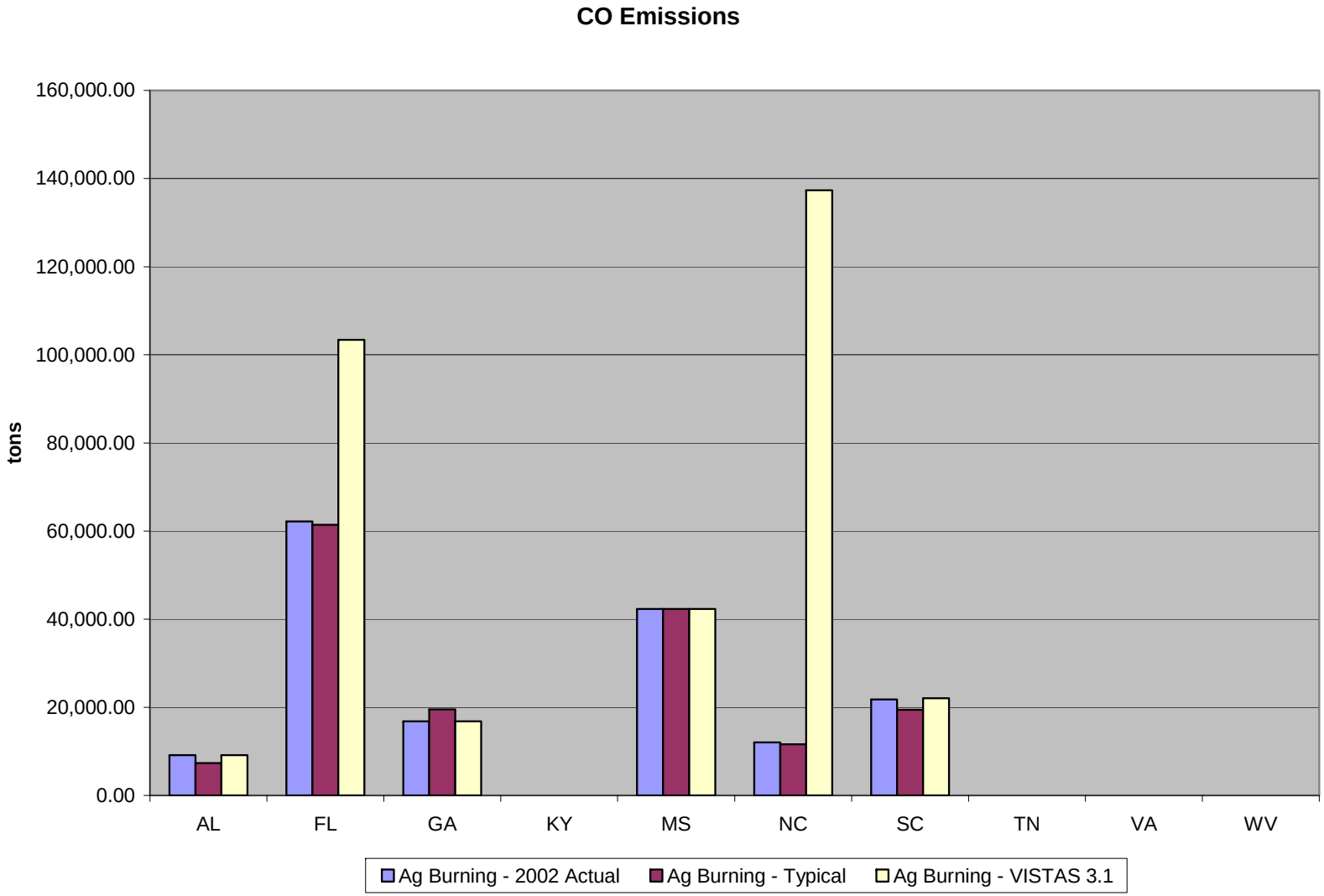


Figure 1.2-2 CO Emissions from Land Clearing Burning for the Original Base Year, 2002 Actual Base G and 2002 Typical Base G Inventories.

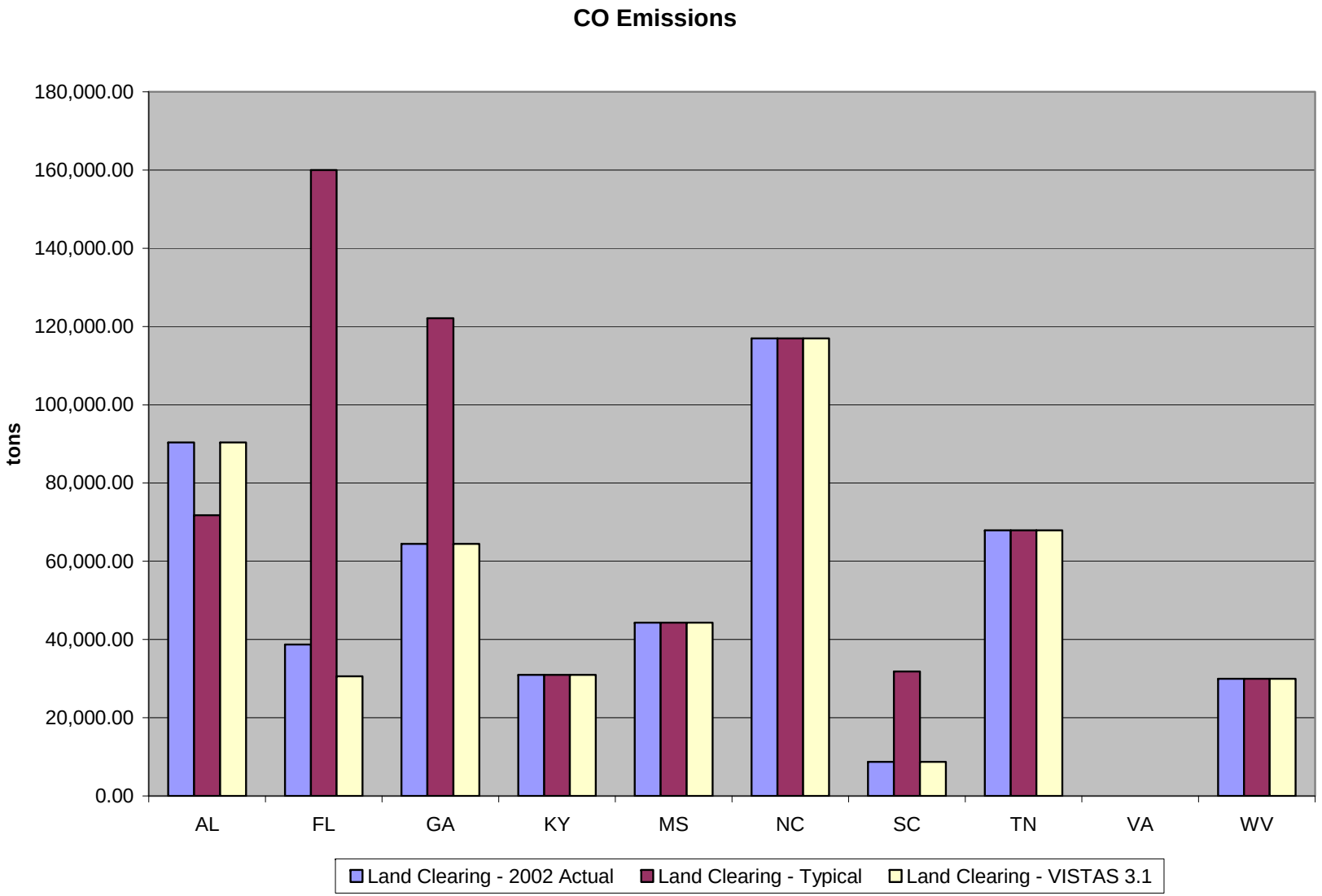


Figure 1.2-3 CO Emissions from Prescribed Burning for the Original Base Year, 2002 Actual Base G and 2002 Typical Base G Inventories.

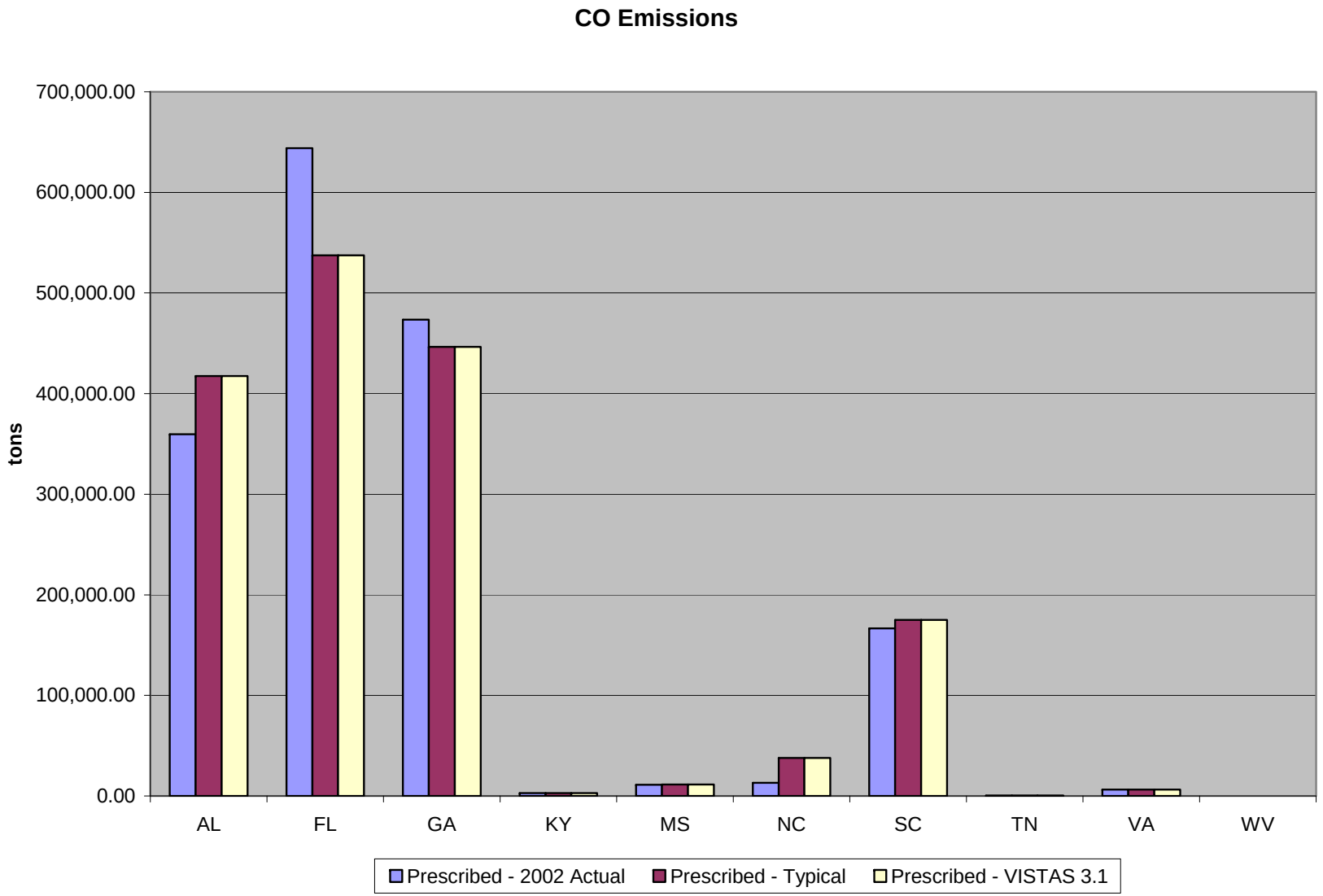
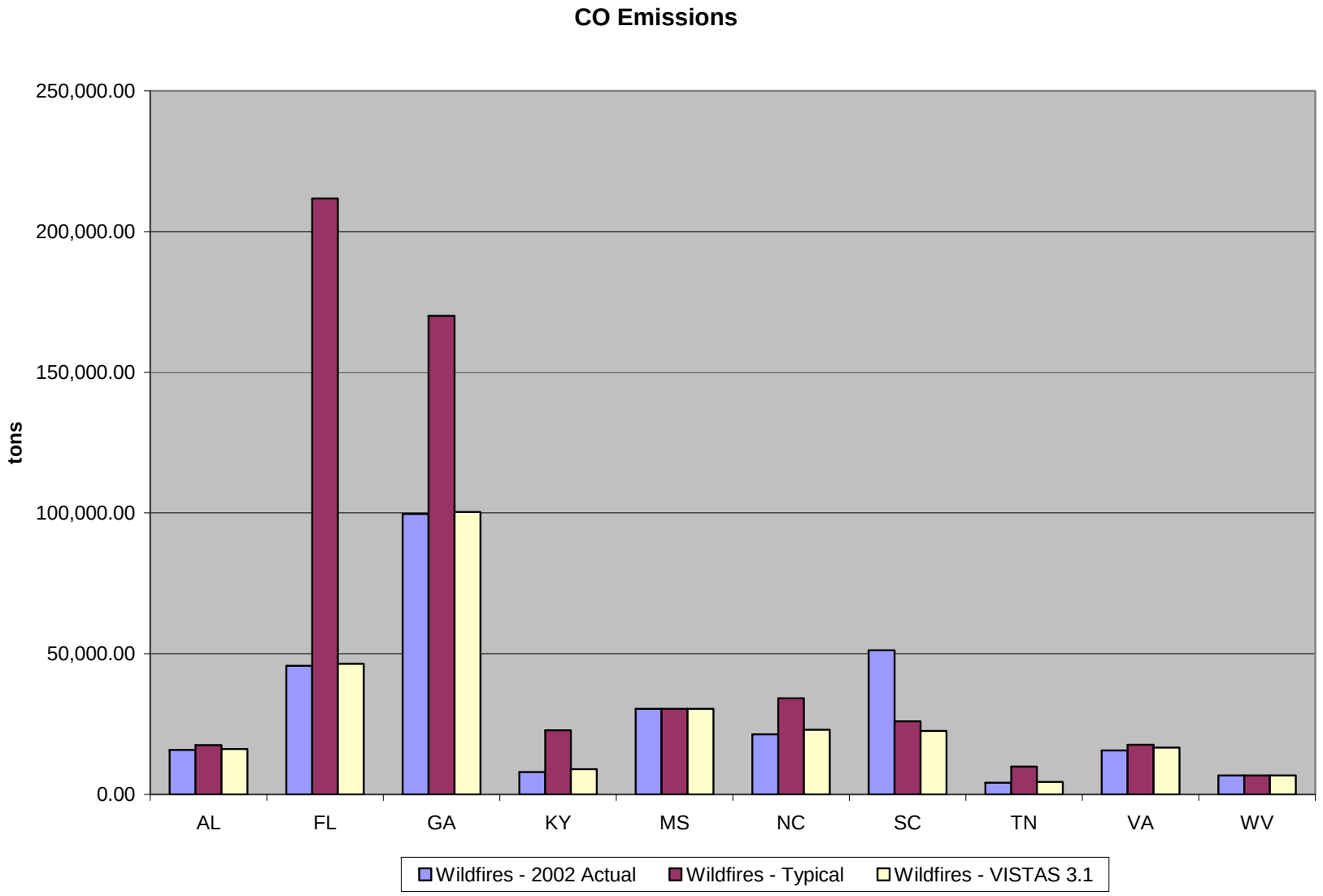


Figure 1.2-4 CO Emissions from Wildfire Burning for the Original Base Year, 2002 Actual Base G and 2002 Typical Base G Inventories.



1.2.2 Development of non-fire inventory

The second task in preparing the area source component of the Base F and Base G 2002 base year inventory was the incorporation of data submitted by the VISTAS States to the EPA as part of the CERR. With few exceptions, Base F and Base G inventories for this component of the inventory are identical. Modifications to the Base F methodology (described below) only resulted from modifications from the VISTAS States during review of the Base F inventory. The changes made to the inventory based on these reviews are described in the last portion of this section of the report. The information presented below describes the method used to incorporate CERR data as part of Base F.

Work on incorporating the CERR data into the 2002 Base F inventory involved: 1) obtaining the data from EPA, 2) evaluating the emissions and pollutants reported in order to avoid double counting and 3) backfilling from the earlier version of the VISTAS 2002 base year inventory for missing sources/pollutants. The processes used to perform those operations are described below. This work did not include any of the fire emission estimates described above. In addition it did not include emission estimates for ammonia from agricultural and fertilizer sources. Finally it did not include PM emissions from paved roads. Each of those categories was estimated separately.

Data on the CERR submittals was obtained from EPA's Draft NEI download file transfer protocol (FTP) site where the data are stored after they've been processed for review. The data submitted in National Emission Inventory Format (NIF) was downloaded from that site. Once all of the files were obtained, MACTEC ran the files through the EPA NIF Format and Content checking tool to ensure that the files were submitted in standard NIF format and that there were no issues with those files. In a couple of cases small errors were found. For example, in one case a county FIPs code that was no longer in use was found. MACTEC contacted each VISTAS State area source contact person to resolve the issues with the files and corrections were made. Once all corrections to the native files were completed, MACTEC continued with the incorporation of the data into the VISTAS area source files.

Our general assumption was that unless we determined otherwise, the CERR submittals represented full and complete inventories. Where a State submitted a complete inventory, our plan was to simply delete the previous 2002 base year data and replace it with the CERR submittal. Prior to this replacement however, we stripped out the following emissions:

1. All wildfire, prescribed burning, land clearing and agricultural burning emissions submitted to EPA by the States as part of the CERR process were removed since they were to be replaced with emissions estimated using methods described earlier.
2. All fertilizer and agricultural ammonia emission records submitted to EPA by the States as part of the CERR process were removed. These were replaced with the estimates developed using the CMU Ammonia model.

3. All emissions from paved roads submitted to EPA by the States as part of the CERR process were removed. These emissions were replaced with updated emissions developed by U.S. EPA as part of their 2002 NEI development effort.

This approach was used for most State and Local emission submittals to prepare the Base F inventory. There were a few cases where alternative data were used to prepare the Base F inventory. In general, these alternatives involved submittal of alternative files to the CERR data by S/L agencies. Table 1.2-2 below summarizes the data used to prepare the Base F inventory. In general the data were derived from one of the following sources:

1. CERR submittal obtained from EPA FTP site as directed by VISTAS States;
2. State submitted file (either revised from CERR submittal or separate format);
3. VISTAS original 2002 base year (VISTAS version 3.1 base year file); or
4. EPA's preliminary 2002 NEI.

Table 1.2-2 Summary of State Data Submittals for the 2002 VISTAS Area Source Base F Inventory

State / Local Program	Area Source Emissions Data Source
AL	B
FL	B
GA	C
KY	A
MS	B
NC	C
SC	B
TN	B
VA	B
WV	A/C
Davidson County, TN	B
Hamilton County, TN	C
Memphis/Shelby County, TN	A
Knox County, TN	B
Jefferson County, AL	* so B from State
Jefferson County, KY	B
Buncombe County, NC	* so C from State
Forsyth County, NC	* so C from State
Mecklenburg County, NC	* so C from State

A = VISTAS 2002 (version 3.1)
B = CERR Submittal from EPA's ftp site
C = Other (CERR or other submittal sent directly from State to MACTEC)
* = No response

In order to track the sources of data in the final Base F and Base G NIF files, a field was added to the NIF format files developed for VISTAS to track each data source. A field named Data_Source was added to the EM table. A series of codes were added to this field to mark the source of each emissions value in the Base F and Base G inventories. Values in this field are detailed in Table 1.2-3.

Table 1.2-3 Data Source Codes and Data Sources for VISTAS 2002 Base F Area Source Emissions Inventory.

Data Source Codes	Data Source
Base F Codes	
CMU Model	CMU Ammonia model v 3.6
E-02-X or E-99-F or L-02-X or S-02-X	EPA CERR submittal (from FTP site)
EPA Paved	EPA Paved Road emissions estimates
EPAPRE02NEI	EPA Preliminary 2002 NEI
STATEFILE	State submitted file
VISTBASYR31	VISTAS 2002 Base Year version 3.1
VISTRATIO	Developed from VISTAS Ratios (used only for missing pollutants)
Additional Base G Codes	
ALBASEGFILE	Base G update file provided by AL
NCBASEGFILE	Base G update file provided by NC
OTAQRPT	Portable Fuel Container Emissions from OTAQ Report
STELLA	Revised data provided by VISTAS EI Advisor Greg Stella
VABASEGFILE	Base G update file provided by VA
VAStateFile	Revisions/additions to Base G update file provided by VA

Most States submitted complete inventories for Base F. Virginia's inventory required a two stage update. Virginia's CERR submittal only contained ozone precursor pollutants (including CO). For Virginia, MACTEC's original plan was to maintain the previous 2002 VISTAS base year emissions for non-ozone pollutants and then do a simple replacement for ozone pollutants. However during the QA phase of the work, MACTEC discovered that there were categories that had ozone precursor or CO emissions in the submittal that weren't in the original 2002 VISTAS base year inventory that should have PM or SO_2 emissions. For those records, MACTEC used an

emissions ratio to build records for emissions of these pollutants. Data for Virginia PM and SO_2 emissions were generated by developing SCC level ratios to NO_x from the VISTAS 2002 base year inventory (version 3.1) or from emission factors and then calculating the emissions based on that ratio.

1.2.3 2002 Base G inventory updates

After the Base F inventory was submitted and used for modeling, VISTAS States were provided an opportunity for further review and comment on the Base F inventory. As a result of this review and comment period, several VISTAS States provided revisions to the Base F inventory.

In addition to and as an outgrowth of some of the comments provided by the States during the review process, some of the changes made to the inventory were made globally across the entire VISTAS region. This section discusses the specific State changes followed by the global changes made to the area source component of the inventory for all VISTAS States.

1.2.3.1 Changes resulting from State review and comment

Alabama

Alabama suggested several changes and had questions concerning a few categories in the Base F inventory. The changes/questions were:

1. For Source Classification Code (SCC) 2102005000 (Industrial Boilers: Residual Oil) and SCC 2103007000 (Institutional/Commercial Heating: Liquefied Petroleum Gas) the Alabama noted that the Base F VISTAS inventory had values for NO_x, VOC and CO for the State, but no values for SO_2, PM_{10} or $PM_{2.5}$.

MACTEC evaluated this information and found that there were actually emissions for two counties in AL for that SCC that had either SO_2 and/or PM emissions. The data used to develop the 2002 Base F inventory for AL came from the preliminary 2002 CERR submittals (see above) which should have included SO_2 and PM but did not except for two counties. According to MACTEC's protocol for use of these files, the files received from EPA were to be used "as is" unless the States provided comments during the Base F comment period to correct the CERR submittal. No comments were received from AL on the CERR submittal used for Base F. For 2002 Base G, AL provided an updated database file for these SCCs for all counties in the State that provided revised values for emissions and included SO_2 and PM. The revised file was used to update the Base F data for Base G.

2. AL noted that the Base F inventory included SCC 2401002000 (Solvent Utilization, Surface Coating, Architectural Coatings - Solvent-based, Total: All Solvent Types) and 2401003000 (Solvent Utilization, Surface Coating,

Architectural Coatings - Water-based, Total: All Solvent Types) as well as SCC 2401001000 (Solvent Utilization, Surface Coating, Architectural Coatings, Total: All Solvent Types). This resulted in double counting of the emissions for this category. AL suggested removal of the breakdown SCCs and use of the total SCC.

MACTEC deleted records for the breakdown SCCs and retained the total all solvents SCC emissions.

3. AL found the SCCs listed below missing from the Base F VISTAS inventory.

SCC	VOC Emissions	SCC Description
2401025000	1139.91	Surface Coatings: Metal Furniture, all coating types
2401030000	425.27	Surface Coatings: Paper, all coating types
2401065000	344.08	Surface Coatings: Electronic and Other Electrical, all coating types
2430000000	504.29	Solvent Utilization, Rubber/Plastics, All Processes, Total: All Solvent Types
2440020000	3043.78	Solvent Utilization, Miscellaneous Industrial, Adhesive (Industrial) Application, Total: All Solvent Types
Total for AL	5457.32	

MACTEC found that the emissions for these SCCs were included in the Base F inventory, but with slightly different total emissions. AL provided an updated county-level emissions file for use in updating the Base G inventory. That file was used to update the NIF records for AL for those SCCs.

4. AL noted that emissions in the Base F inventory were found for SCC 2465000000 and SCCs 2465100000, 2465200000, 2465400000, 2465600000, and 2465800000. These last five SCCs represent a subset of the emissions in the 246500000 SCC resulting in potential double counting of emissions.

MACTEC deleted all emissions associated with the Total SCC 2465000000 and retained the subset SCCs for the Base G inventory.

Florida

Florida provided comments indicating that they felt that emissions from the following sources and counties were too high, especially for CO and PM and were likely zero:

- motor vehicle fire - Palm Beach County
- woodstoves - Miami Dade, Hillsborough, Orange, Polk, Ft Myers, Pasco and Sarasota Counties
- fireplaces - Miami Dade and Hillsborough Counties

Emissions from these sources in the counties specified were set to zero by MACTEC for the Base G inventory.

North Carolina

North Carolina provided corrected emission files for 2002 Base F. A text file with emission values was provided and used to update the Base F emissions to Base G. The updated emissions were applied directly to the Base F NIF file. The file provided was similar to the "EM" NIF table. An update query was used to update the data supplied in the text file to the Access database NIF file. All changes were implemented.

South Carolina

South Carolina had two issues concerning the Base F inventory. These issues related to 1) additional SCCs that were in BASE F 2009 and 2018, but not in 2002 Base F and 2) SCCs that were in the U.S. EPA 2002 NEI inventory, but not in the VISTAS 2002, 2009, or 2018 Base F inventory.

MACTEC investigated the additional SCCs found in 2009 and 2018 Base F and found that the SCCs actually were not missing in the 2002 Base F inventory but only had emissions for PM. Thus the emissions were maintained as they were provided in Base F.

With respect to the SCCs that were found in the U.S. EPA 2002 NEI, MACTEC investigated and found that they were not included in the Base F inventory because they were not included in the 2002 CERR submittal used to produce the Base F updates. The SCCs were apparently added by EPA later in the NEI development process. In addition, MACTEC also evaluated whether or not the SCCs were found in other VISTAS States Base F inventories. MACTEC found that some States included them and some did not, there was no consistency between the States. MACTEC also found that typically emissions for these SCCs were low in emissions, generally with emissions of only a few tons to tens of tons per year. The decision was made with South Carolina concurrence not to add these SCCs to the Base G inventory. These SCCs were: 210205000, 2102011000, 2103007000, 2103011000, 2104007000, 2104011000, 2302002100, 2302002200, 2302003100, 2302003200, 2610000500, 2810001000, and 281001500.

Virginia

Virginia provided an updated 2002 base year emissions file. The data in that file were used to update the Base F inventory emission values to those for Base G. In addition, Virginia provided information on several source categories that required controls for future year projections since the sources were located in counties/cities in northern Virginia and were subject to future year Ozone Transport Commission (OTC) regulations. MACTEC added in the base year control levels to the Base G inventory file for these categories so that they could be estimated correctly in future years. The controls added were for mobile equipment repair/refinishing sources, architectural and industrial maintenance coating sources, consumer products sources, and solvent metal cleaning sources. Minor errors were found in some entries for the initial file provided and VA provided a revised file with corrections and minor additions.

1.2.4 Ammonia and paved road emissions

The final component of the Base F inventory development was estimation of NH_3 emission estimates for livestock and fertilizers and paved road PM emissions. For the NH_3 emission estimates for livestock and fertilizers we used version 3.6 of the CMU NH_3 model (http://www.cmu.edu/ammonia/). Results from this model were used for all VISTAS States. The CMU model version 3.6 was used in large part because it had been just recently been updated to include the latest (2002) Census of Agriculture animal population statistics. Prior to inclusion of the CMU model estimates, MACTEC removed any ammonia records for agricultural livestock or fertilizer emissions from the VISTAS 2002 initial base year inventory. MACTEC also generated emissions from human perspiration and from wildlife using the CMU model and added those emissions for each State.

For the Base G ammonia inventory, MACTEC removed all wildlife and human perspiration emissions. VISTAS decided to remove these emissions from the inventory. Human perspiration was dropped due to a discrepancy in the units used for the emission factor that was not resolved prior to preparing the estimates and wildlife was dropped because VISTAS felt the activity data was too uncertain. Thus all emissions from these two categories were deleted in the Base G 2002 inventory.

For the paved road PM Base F emissions, we used the most recent estimates developed by EPA as part of the NEI development effort (Roy Huntley, U.S. EPA, email communication, 8/30/2004). EPA had developed an improved methodology for estimating paved road emissions for 2002 and had used that method to calculate emissions for that source category. MACTEC obtained those emissions from EPA and those values were substituted directly into the inventory after receiving consensus from all of the VISTAS States to perform the replacement. These files were obtained in March of 2005 in NIF format from the EPA FTP site.

For the Base G emissions, modifications were made to the emissions estimates based on changes suggested by work of the Western Regional Air Partnership and U.S. EPA. Details of these changes are provided below in the section on global changes made as part of the Base G inventory updates.

1.2.5 Global Changes Made for Base G

There were three global changes made between the Base F and the Base G inventory (beyond the removal of wildlife and human perspiration NH_3 emissions). These changes were:

1. Removal of Stage II emissions from the area source inventory and inclusion in the mobile sector of the inventory,
2. Adjustment of fugitive dust $PM_{2.5}$ emissions, and
3. Addition of emissions from portable fuel containers.

As part of the Base F review process, several VISTAS States had expressed surprise that the Stage II refueling emission estimates were in the area source component of the inventory. This decision had been made with SIWG agreement early on in the inventory development process because 1) some States had included it in their CERR submittals and 2) because the non-road and on-road mobile estimates had differing activity factor units and could not be easily combined. However for Base G, the VISTAS States all agreed, especially in light of the different ways in which the emissions were reported in the CERR, to remove the Stage II refueling emissions from the area source inventory and include them in the non-road and on-road sectors. Thus all records related to Stage II refueling were removed from the area source component of the Base G inventory.

$PM_{2.5}$ emissions from several fugitive dust sources were also updated for Base G. The Western Regional Air Partnership (WRAP) and U.S. EPA had been investigating overestimation of the $PM_{2.5}$ / PM_{10} ratio in several fugitive dust categories and U.S. EPA was in the process of making revisions to AP-42 for several categories during preparation of the Base G inventory. Based on data received from U.S. EPA, VISTAS decided to revise the $PM_{2.5}$ emissions from construction, paved roads and unpaved road sources. $PM_{2.5}$ emissions in Base F were multiplied by 0.67, 0.6, and 0.67 for construction, paved roads and unpaved roads respectively to produce the values found in Base G. No changes were made to PM_{10}, only to $PM_{2.5}$.

Finally, as part of Virginia's comments on the Base F inventory, emissions from portable fuel containers were mentioned as being absent from the inventory. MACTEC was tasked with developing a methodology that could be used to add these emissions to the Base G area source inventory. In investigating options for a method of estimating emissions, MACTEC found that the U.S. EPA had prepared a national inventory of emissions by State for portable fuel

containers. Data on emissions from this source prepared by U.S. EPA were presented in, "Estimating Emissions Associated with Portable Fuel Containers (PFCs), Draft Report, Office of Transportation and Air Quality, United States Environmental Protection Agency, Report # EPA420-D-06-003, February 2006".

State-level emission estimates for 2005 derived from Appendix Table B-2 of the PFCs report were used as the starting point for developing 2002 county-level emissions estimates. State emissions were derived from that table by using all of the emission estimates in that table with the exception of values for vapor displacement and spillage from refueling operations. Those components of the State emissions were left out of the State-level emissions to avoid double counting refueling emissions in the non-road sector. For the purposes of 2002 emission estimates for Base G, the 2005 values were assumed equal to 2002 values.

The 2005 State-level estimates minus the refueling component from Appendix Table B-2 of the report were summed for each State and then allocated to the county-level. The county-level allocation was based on the fuel usage information obtained from the NONROAD 2005 model runs conducted as part of the Base G inventory development effort (see the 2002 base year Base G non-road section below). MACTEC used the spillage file from the NONROAD model (normally located in the DATA\EMSFAC directory in a standard installation of NONROAD) to determine the SCCs that used containers for refueling. The spillage file contains information by SCC and horsepower indicating whether or not the refueling occurs using a container or a pump. All SCC and horsepower classes using containers were extracted from the file and cross-referenced with the fuel usage by county for those SCC/horsepower combinations from the appropriate year model runs (2002, 2009 or 2018). Then the fuel usages by county from the NONROAD 2005 runs prepared for VISTAS were summed for those SCCs by county. The county level fuel use was then divided by the State total fuel use for the same SCCs to determine the fraction of total State fuel usage and that fraction was used to allocate the State-level emissions to the county.

1.2.6 Quality Assurance steps

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, and to ensure that a full and complete inventory was developed for VISTAS. Quality assurance was an important component to the inventory development process and MACTEC performed the following QA steps on the area source component of the 2002 Base F inventory:

1. All CERR and NIF format State supplied data submittals were run through EPA's Format and Content checking software.

2. SCC level emission summaries were prepared and evaluated to ensure that emissions were consistent and that there were no missing sources.

3. Tier comparisons (by pollutant) were developed between the revised 2002 base year inventory and the previous (version 3.1) base year inventory.

4. Fields were either added or used within each NIF data table to track the sources of data for each emission record.

5. Data product summaries were provided to both the VISTAS Emission Inventory Technical Advisor and to Area Source and Fires SIWG representatives for review and comment. Changes based on these comments were implemented in the files.

6. Version numbering was used for all inventory files developed. The version numbering process used a decimal system to track major and minor changes. For example, a major change would result in a version going from 1.0 to 2.0. A minor change would cause a version number to go from 1.0 to 1.1. Minor changes resulting from largely editorial changes would result in a change from 1.00 to 1.01.

In addition, for the fires inventory, data related to fuel loading and fuel consumption was reviewed and approved by the VISTAS Fire SIWG to ensure that values used for each type of fire and each individual fire were appropriate. Members of the VISTAS Fire SIWG included representatives from most State Divisions of Forestry (or equivalent) as well as U.S. Forest Service and National Park Service personnel.

For Base G, similar QA steps to those outlined above for Base F were undertaken. In addition, all final NIF files were checked using the EPA Format and Content checking software and summary information by State and pollutant were prepared comparing the Base F and Base G inventories.

1.3 Mobile Sources

This section describes the revisions made to the initial 2002 VISTAS Base Year emission inventory on-road mobile source input files. For this work actual emission estimates were not made, rather data files consistent with Mobile Emissions Estimation Model Version 6 (MOBILE6) were developed and provided to the VISTAS modeling contractor. These input data files were then run during the VISTAS modeling to generate on-road mobile source emissions using episodic and meteorological specific conditions configured in the sparse matrix operator Kernel Emissions modeling system (SMOKE) emissions processor.

During initial discussions with the VISTAS Mobile Source SIWG, some States indicated a desire to use CERR mobile source emissions data in place of the VISTAS 2002 inventories generated by E.H. Pechan and Associates, Inc. (the initial VISTAS 2002 Base Year inventory files).

However, the CERR emissions data by itself were not sufficient for an inventory process that includes both base and future year inventories. MACTEC needed to be able to replicate the CERR data rather than simply obtain CERR emissions estimates. The reason for this is that only input files were being prepared to provide revised 2002 estimates during the VISTAS modeling process, rather than the actual emission estimates and that the 2002 input data files would be used as a starting point for the projected emission estimates. This meant that the appropriate vehicle miles traveled (VMT), MOBILE6, and/or NONROAD model input data needed to be provided. If these data were provided with the CERR emissions estimates we used it as the starting point for revision of the 2002 Base Year inventory. However MACTEC did not have access to the on-road mobile CERR submissions from EPA, so re-submittal of these data directly to MACTEC was requested in order to begin compiling the appropriate input file data.

In those cases where States did not provide CERR on-road mobile source input data files, our default approach was to maintain the data input files and VMT estimates for the initial 2002 Base Year inventory prepared by Pechan.

1.3.1 Development of on-road mobile source input files and VMT estimates

Development of the 2002 on-road input files and VMT was a multi-step process depending upon what the State mobile source contacts instructed us to use as their data. Information provided below provides incremental revisions made to on-road mobile source inventories or inputs in series from one inventory version to the next. In general the process involved one of three steps from the original 2002 on-road mobile source data.

Base F Revisions

1. The first step was to evaluate the initial 2002 base year files and make any non-substantive changes (i.e., changes only to confirm that the files posted for 2002 by Pechan were executable and that all the necessary external files needed to run MOBILE6 were present). This approach was taken for AL, FL, GA, MS, SC, and WV. For these States the determination was made that the previous files would be okay to use as originally prepared. For SC, the VMT file was updated, but that did not affect the MOBILE6 input files.

2. For other States, modification to the input files was required. The information below indicates what changes were made for other States in the VISTAS region.

KY – For Kentucky, the Inspection and Maintenance (I/M) records in the input files for Jefferson County were updated in order to better reflect the actual I/M program in the Louisville metropolitan area.

NC - Substantial revisions were implemented to these input files based on input from the State. The modifications necessary to reflect the desires of the State led to complete replacement of the previous input files. Among the changes made were:

- The regrouping of counties (including the movement of some counties from one county group to another and the creation of new input files for previously grouped counties). There were originally 32 input files; after the changes there were 49. The pointer file was corrected to reflect these changes.
- Travel speeds were updated in over 3000 scenarios.
- All I/M records were updated.
- All registration distributions were updated.
- I/M VMT fractions were updated (which only affected the pointer file).
- VMT estimates were updated (which has no direct effect on the MOBILE6 input files but does ultimately affect emissions).

3. VA and TN – For these States, new input files were provided due to substantive changes that the State wanted to make relative to the 2002 initial base year input files. In addition, revised VMT data were developed for each State.

Base G Revisions

For the production of the VISTAS 2002 Base G inventory, VISTAS states reviewed the Base F inputs, and provided corrections, updates and supplemental data.

For all states modeled, the Base G updates include:

Adding Stage II refueling emissions calculations to the SMOKE processing.

Revised the HDD compliance for all states. (REBUILD EFFECTS = .1)

In addition to the global changes, individual VISTAS states made the following updates:

KY – updated VMT and M6 input values for selected counties.

NC – revised VMT and registration distributions.

TN - revised VMT and vehicle registration distributions for selected counties.

VA – revised winter RFG calculations in Mobile 6 inputs.

WV – revised VMT input data.

AL, FL, and GA did not provide updates for Base G and therefore the Base F inputs were used for these States.

1.3.1.1 Emissions from on-road mobile sources

The MOBILE6 module of the Sparse Matrix Operator Kernel Emissions (SMOKE) model was used to develop the on-road mobile source emissions estimates for CO, NO_X, NH_3, SO_2, PM, and VOC emissions. The MOBILE6 parameters, vehicle fleet descriptions, and VMT estimates are combined with gridded, episode-specific temperature data to calculate the gridded, temporalized emission estimates. The MOBILE6 emissions factors are based on episode-specific temperatures predicted by the meteorological model. Further, the MOBILE6 emissions factors model accounts for the following:

- Hourly and daily minimum/maximum temperatures;
- Facility speeds;
- Locale-specific inspection/maintenance (I/M) control programs, if any;
- Adjustments for running losses;
- Splitting of evaporative and exhaust emissions into separate source categories;
- VMT, fleet turnover, and changes in fuel composition and Reid vapor pressure (RVP).

The primary input to MOBILE6 is the MOBILE shell file. The MOBILE shell contains the various options (e.g. type of inspection and maintenance program in effect, type of oxygenated fuel program in effect, alternative vehicle mix profiles, RVP of in-use fuel, operating mode) that direct the calculation of the MOBILE6 emissions factors. The shells used in these runs were based on VISTAS Base F modeling inputs as noted in the previous section.

For this analysis, the on-road mobile source emissions were produced using selected weeks (seven days) of each month and using these days as representative of the entire month. This selection criterion allows for the representation of day-of-the-week variability in the on-road motor vehicles, and models a representation of the meteorological variability in each month. The modeled weeks were selected from mid-month, avoiding inclusion of major holidays.

The parameters for the SMOKE runs are as follows:

Episodes:

2002 Initial Base Year, and

2009 and 2018 Future years, using 2009/2018 inventories and modeled using the same meteorology and episode days as 2002.

Episode represented by the following weeks per month:

January 15-21
February 12-18
March 12-18
April16-22
May 14-20
June 11-17
July 16-22
August 13-19
September 17-23
October 15-21
November 12-18
December 17-23

Days modeled as holidays for annual run:

New Year's Day - January 1
Good Friday – March 29
Memorial Day – May 27
July 4th
Labor Day – September 2
Thanksgiving Day – November 28, 29
Christmas Eve – December 24
Christmas Day – December 25

Output time zone:

Greenwich Mean Time (zone 0)

Projection:

Lambert Conformal with Alpha=33, Beta=45, Gamma=-97, and center at (-97, 40).

Domain:

36 Kilometer Grid: Origin at (-2736, -2088) kilometers with 148 rows by 112 columns and 36-km square grid cells.
12 Kilometer Grid: Origin at (108, -1620) kilometers with 168 rows by 177 columns and 12-km square grid cells.

CMAQ model species:

The CMAQ configuration was CB-IV with PM. The model species produced were: CO, NO, NO_2, ALD_2, ETH, FORM, ISOP, NR, OLE, PAR, TERPB, TOL, XYL, NH_3, SO_2, SULF, PEC, PMFINE, PNO_3, POA, PSO_4, and PMC.

Meteorology data:

Daily (25-hour). SMOKE requires the following five types of MCIP outputs: (1) Grid cross 2-d, (2) Grid cross 3-d, (3) Met cross 2-d, (4) Met cross 3-d, and (5), Met dot 3-d.

The reconstructed emissions based on the representative week run were calculated by mapping each day of week (Mon, Tue, Wed, etc.) from the modeled month to the same day of week generated in the representative week run. In the case of holidays, these days were mapped to representative week Sundays. An example of this mapping for the January episode is presented in Table 1.3-1 below. Note that although the emissions were generated for individual calendar years (2002, 2009 and 2018) the meteorology is based on 2002.

Table 1.3-1 Representative day mapping for January episode

(Highlighted representative week)

Modeled Date	Representative Day	Modeled Date	Representative Day	Modeled Date	Representative Day
1/1/2002*	1/20/2002	1/11/2002	1/18/2002	1/22/2002	1/15/2002
1/2/2002	1/16/2002	1/12/2002	1/19/2002	1/23/2002	1/16/2002
1/3/2002	1/17/2002	1/13/2002	1/20/2002	1/24/2002	1/17/2002
1/4/2002	1/18/2002	1/14/2002	1/21/2002	1/25/2002	1/18/2002
1/5/2002	1/19/2002	1/15/2002	1/15/2002	1/26/2002	1/19/2002
1/6/2002	1/20/2002	1/16/2002	1/16/2002	1/27/2002	1/20/2002
1/7/2002	1/21/2002	1/17/2002	1/17/2002	1/28/2002	1/21/2002
1/8/2002	1/15/2002	1/18/2002	1/18/2002	1/29/2002	1/15/2002
1/9/2002	1/16/2002	1/19/2002	1/19/2002	1/30/2002	1/16/2002
1/10/2002	1/17/2002	1/20/2002	1/20/2002	1/31/2002	1/17/2002
		1/21/2002	1/21/2002		

* Modeled holiday

1.3.2 Development of non-road emission estimates

Emissions from non-road sources were estimated in two steps. First, emissions for non-road sources that are included in the NONROAD model were developed. Second, emissions from sources not included in the NONROAD model were estimated. The sections below detail the procedures used for each group of sources.

1.3.2.1 Emissions from NONROAD model sources

An initial 2002 base year emissions inventory for non-road engines and equipment covered by the EPA NONROAD model was prepared for VISTAS in early 2004. The methods and assumptions used to develop the inventory are presented in a February 9, 2004 report "*Development of the VISTAS Draft 2002 Mobile Source Emission Inventory (February 2004 Version)*" as prepared by E.H. Pechan & Associates, Inc. Except as otherwise stated below, all

aspects of the preparation methodology documented in that report continue to apply to the revised NONROAD modeling discussed in this section.

Revisions to the initial 2002 NONROAD emissions inventory were implemented to ensure that the latest State and local data were considered, as well as to more accurately reflect gasoline sulfur contents for 2002 and correct other State-specific discrepancies. Those revisions comprise the Base F VISTAS non-road inventory. This section details the specific revisions made to the NONROAD model input files for the Base F and Base G VISTAS base year inventories, and provides insight into some key differences between the versions of the NONROAD model employed for the Base F and Base G inventories and the previous version employed for the initial 2002 base year inventory prepared by Pechan.

Revisions to the initial 2002 emissions inventory prepared by Pechan were actually implemented in two stages. An initial set of revisions was implemented in the fall of 2004. Those revisions resulted in the Base F inventory. These were followed by a second set of revisions in the spring of 2006. Those estimates produced the Base G base year inventory. To accurately document the combined effects of both sets of revisions, each set is discussed separately below. Unless otherwise indicated, all revisions implemented in Base F were carried directly into the Base G revision process without change. Thus, the inventories that resulted from the Base F revisions served as the starting point for the Base G revisions.

For Base F, three VISTAS States provided detailed data revisions for consideration in developing revised model inputs. These States were:

1. North Carolina
2. Tennessee (including a separate submission for Davidson County), and
3. Virginia.

The remaining seven VISTAS States indicated that the initial 2002 VISTAS input files prepared by Pechan continued to reflect the most recent data available. These States were:

1. Alabama,
2. Florida,
3. Georgia,
4. Kentucky,
5. Mississippi,
6. South Carolina, and
7. West Virginia.

However, it should be recognized that the NONROAD input files for *all* ten VISTAS States were updated to reflect gasoline sulfur content revisions for the Base F 2002 base year inventory (as

discussed below). The original files prepared by Pechan are available on their FTP site in the /pub/VISTAS/MOB_0104/ directory.

Before presenting the specific implemented revisions, it is important to note that the Base F 2002 base year inventory utilized a newer release of the NONROAD model than was used for the initial 2002 base year inventory (prepared by Pechan). The Base F 2002 base year inventory, as developed in spring 2004, was based on the Draft NONROAD2004 model, which was released by the EPA in May of 2004. This model is no longer available on EPA's website. The initial 2002 base year inventory (prepared by Pechan) was based on the Draft NONROAD2002a version of the model (which is also no longer available on EPA's website). Key differences between the models are as follows:

- Draft NONROAD2004 included the effects of the Tier 4 non-road engine and equipment standards (this did not impact the Base F 2002 inventory estimates, but did affect Base F future year forecasts).
- Draft NONROAD2004 included the *exhaust* emission impacts of the large spark-ignition engine standards; the evaporative impacts of these standards are *not* incorporated (this does not impact 2002 inventory estimates, but does affect future year forecasts).
- Draft NONROAD2004 included revised equipment population estimates.
- The $PM_{2.5}$ fraction for *diesel* equipment in Draft NONROAD2004 had been updated from 0.92 to 0.97.
- Draft NONROAD2004 included revisions to recreational marine activity, useful life, and emission rates.

To the extent that these revisions affect 2002 emissions estimates, they will be reflected as differentials between the initial and Base F 2002 VISTAS base year inventories. It is perhaps important to identify that, at the time of the Base F inventory revisions; the EPA recognized the Draft NONROAD2004 model as an appropriate mechanism for SIP development. Although the model was designated as a draft update, it reflected the latest and most accurate NONROAD planning data at that time, as evidenced by the EPA's use of that version for the Tier 4 Final Rulemaking.

Prior to the Base G inventory revisions implemented in 2006, the EPA released another updated version of the NONROAD model, designated as Final NONROAD2005 (which can be downloaded from: http://www.epa.gov/OMSWWW/nonrdmdl.htm#model). This version ostensibly represents the final version of the model, although certain components of it have been updated since its first release in December 2005. For the Base G inventory developed in the first

half of 2006, all updates of the Final NONROAD2005 model through March 2006 are included. Key differences between Final NONROAD2005 and Draft NONROAD2004 are as follows:

- Final NONROAD2005 reflects the latest basic emission rate and deterioration data.
- Final NONROAD2005 includes emission estimates for a range of evaporative emissions categories not included in Draft NONROAD2004 (tank and hose permeation, hot soak, and running loss emissions).
- Final NONROAD2005 includes a revised diurnal emissions algorithm.
- Final NONROAD2005 includes a revised equipment scrappage algorithm.
- Final NONROAD2005 includes revised state and county equipment allocation data.
- Final NONROAD2005 allows separate sulfur content inputs for marine and land-based diesel fuel.
- Final NONROAD2005 includes revised conversion factors for hydrocarbon emissions.
- Final NONROAD2005 includes the evaporative emission impacts of the large spark-ignition engine standards (this does not impact 2002 inventory estimates, but does affect future year forecasts).

Unfortunately, due to the extensive revisions associated with Final NONROAD2005, input files created for use with Draft NONROAD2004 (e.g., Base F input files) and earlier versions of the model cannot be used directly with Final NONROAD2005 (used for Base G). This created a rather significant impact in that the VISTAS NONROAD modeling process involves the consideration of over 200 unique sets of input data. To avoid creating new input files for each of these datasets, a conversion process was undertaken wherein each of the Draft NONROAD2004 (Base F) input data files were converted into the proper format required for proper execution in Final NONROAD2005 (Base G).[1] This process consisted of the following steps:

- Revise the Draft NONROAD2004 (Base F) input files to include the following two line EPA-developed comment at the end of the input file header (this is a nonsubstantive change implemented solely for consistency with input files produced directly using Final NONROAD2005):

[1] The necessary conversions where developed by comparing substantively identical input files created using the graphical user interfaces for both Draft NONROAD2004 and Final NONROAD2005. The differences between the input files indicated the specific revisions necessary to convert existing VISTAS input files into Final NONROAD2005 format.

```
9/2005 epa: Add growth & tech years to OPTIONS packet
 and Counties & Retrofit files to RUNFILES packet.
```

- Revise the Draft NONROAD2004 (Base F) input files to include the following two command lines after the "Weekday or weekend" command in the PERIOD packet:

```
Year of growth calc:
Year of tech sel  :
```

- Revise the Draft NONROAD2004 (Base F) input files to include the following command line after the "Diesel sulfur percent" command in the OPTIONS packet:

```
Marine Dsl sulfur %: 0.2638
```

  Note that the value 0.2638 (2638 parts per million by weight [ppmW]) is applicable only for 2002 modeling and was accordingly revised (as described below) for both the 2009 and 2018 Base G forecast inventories. The 2638 ppmW sulfur value for 2002 marine diesel fuel was taken from the 48-State (excludes Alaska and Hawaii) tabulation presented in the April 27, 2004 EPA document "*Diesel Fuel Sulfur Inputs for the Draft NONROAD2004 Model used in the 2004 Non-road Diesel Engine Final Rule*." It should also be noted that this value differs by about 5 percent from the 2500 ppmW value previously used for the initial 2002 VISTAS modeling (performed by Pechan). Prior to Final NONROAD2005 (used for Base G), the NONROAD model allowed only a single diesel fuel sulfur input that was applied to both land-based and marine equipment. As documented in the February 9, 2004 report "*Development of the VISTAS Draft 2002 Mobile Source Emission Inventory (February 2004 Version)*" as prepared by E.H. Pechan & Associates, Inc., a value of 2500 ppmW sulfur was used for all 2002 VISTAS NONROAD modeling. Given the ability of Final NONROAD2005 to distinguish a separate sulfur content for marine equipment and the existing EPA guidance document suggesting an appropriate marine sulfur value of 2638 ppmW for 2002, the existing modeling value of 2500 ppmW was modified (for marine equipment only).

- Replace the Draft NONROAD2004 (Base F) input files RUNFILES packet command line:

```
TECHNOLOGY      : c:\non-road\data\tech\tech.dat
```

  with the command lines:

```
EXH TECHNOLOGY   : c:\non-road\data\tech\tech-exh.dat
EVP TECHNOLOGY   : c:\non-road\data\tech\tech-evp.dat
```

- Revise the Draft NONROAD2004 (Base F) input files to include the following two command lines after the "EPS2 AMS" command in the RUNFILES packet:

```
US COUNTIES FIPS  : c:\non-road\data\allocate\fips.dat
RETROFIT      :
```

- Revise the Draft NONROAD2004 (Base F) input files to include the following command line after the "Rec marine outbrd" command in the ALLOC FILES packet:

```
Locomotive NOx   : c:\non-road\data\allocate\XX_rail.alo
```

  Where "XX" varies across input files. For any given file, "XX" is the two digit abbreviation of the state associated with the scenario being modeled (e.g., for Alabama modeling, XX=AL).

- Replace the Draft NONROAD2004 (Base F) input files EMFAC FILES packet command line:

```
Diurnal      : c:\non-road\data\emsfac\diurnal.emf
```

  with the eight command lines:

```
Diurnal      : c:\non-road\data\emsfac\evdiu.emf
TANK PERM     : c:\non-road\data\emsfac\evtank.emf
NON-RM HOSE PERM  : c:\non-road\data\emsfac\evhose.emf
RM FILL NECK PERM : c:\non-road\data\emsfac\evneck.emf
RM SUPPLY/RETURN  : c:\non-road\data\emsfac\evsupret.emf
RM VENT PERM    : c:\non-road\data\emsfac\evvent.emf
HOT SOAKS     : c:\non-road\data\emsfac\evhotsk.emf
RUNINGLOSS     : c:\non-road\data\emsfac\evrunls.emfEVP
```

- Revise the Draft NONROAD2004 (Base F) input files to include the following command line after the "PM exhaust" command in the DETERIORATE FILES packet:

```
Diurnal      : c:\non-road\data\detfac\evdiu.det
```

Once revised in this format, the VISTAS non-road input files developed for use with Draft NONROAD2004 (Base F) were executable under the Final NONROAD2005 model (Base G).

The only additional revisions implemented to develop a Final NONROAD2005-based inventory (Base G) involved elimination of non-default equipment allocation files for North Carolina and West Virginia. Due to concerns about improper equipment allocation across counties under the Draft NONROAD2004 model (used for Base F), as well as for earlier versions of the NONROAD model, North Carolina had produced alternative allocation data files indicating the

number of employees in air transportation by county, the number of wholesale establishments by county, and the number of employees in landscaping services by county. For the same reason, West Virginia had produced alternative equipment allocation files indicating the number of employees in air transportation by county, the tonnage of underground coal production by county, the number of golf courses and country clubs by county, the number of wholesale establishments by county, the number of employees in logging operations by county, the number of employees in landscaping services by county, the number of employees in manufacturing operations by county, the number of employees in oil and gas drilling and extraction operations by county, and the number of recreational vehicle parks and campgrounds by county. These alternative equipment allocation files were used for all VISTAS inventory modeling conducted prior to the release of Final NONROAD2005 (i.e., through Base F). However, both North Carolina and West Virginia determined that the default allocation file revisions associated with the release of Final NONROAD2005 were appropriate to address the concerns that led to the development of the alternative allocation files. As a result, all alternative allocation file commands were removed from VISTAS NONROAD2005 (Base G) input files for North Carolina and West Virginia, so that the entire region under the Base G inventory is now modeled using the default allocation files provided with NONROAD2005.

In addition to the alternative equipment allocation files, North Carolina had previously developed an alternative seasonal adjustment file that was used for the Base F inventory in place of the default file provided with Draft NONROAD2004 (and earlier model versions). The alternative data file implemented a single change, namely reclassifying North Carolina as a southeastern state rather than a mid-Atlantic state (as identified in the default data file). Since Final NONROAD2005 continues to identify North Carolina as a mid-Atlantic state, North Carolina requested that the southeastern reclassification be continued for all NONROAD2005 modeling (Base G). To ensure that any other revisions associated with the seasonal adjustment file released with NONROAD2005 were not overlooked, the previously developed alternative seasonal adjustment file for North Carolina was scrapped and a new alternative file was created from the default seasonal adjustment file provided with Final NONROAD2005 for Base G inventory development. The alternative file, which was used for all North Carolina modeling, reclassifies North Carolina from a mid-Atlantic to a southeastern state. This represents the only non-default data file used for VISTAS NONROAD2005-based (Base G) modeling.

The remainder of this section documents all changes to the originally established VISTAS input file values as documented in the February 9, 2004 report "*Development of the VISTAS Draft 2002 Mobile Source Emission Inventory (February 2004 Version)*" as prepared by E.H. Pechan & Associates, Inc. Unless specifically stated below, all values from that report continue to be used without change in the latest VISTAS modeling.

Base F Revisions:

For the initial 2002 base year inventory (developed by Pechan), all NONROAD modeling runs for VISTAS were performed utilizing a gasoline sulfur content of 339 ppmW and a diesel sulfur content of 2,500 ppmW. Although the EPA-recommended non-road diesel fuel sulfur content for 2002 is 2,283 ppmW, the 2,500 ppmW sulfur content used for the initial 2002 base year VISTAS inventory was designed to remove the effect of lower non-road diesel fuel sulfur limits applicable only in California. (The EPA recommended inputs can be found in "*Diesel Fuel Sulfur Inputs for the Draft NONROAD2004 Model used in the 2004 Non-road Diesel Engine Final Rule*," EPA, April 27, 2004.) This correction is appropriate and was retained for the Base F 2002 inventory. Thus, the Base F inventory continued to assume a diesel fuel sulfur content of 2,500 ppmW across the VISTAS region.

However, 339 ppmW is not the EPA recommended 2002 gasoline sulfur content for either eastern conventional gasoline areas or Federal Reformulated Gasoline (RFG) areas. The recommended sulfur content for eastern conventional gasoline is 279 ppmW year-round, while the recommended sulfur content for RFG areas is 129 ppmW during the summer season and 279 ppmW during the winter season. (Conventional gasoline and RFG sulfur contents for 2002 can be found in "*User's Guide to MOBILE6.1 and MOBILE6.2, Mobile Source Emission Factor Model*," EPA420-R-03-010, U.S. EPA, August 2003 [pages 149-155] (available at link at http://www.epa.gov/otaq/m6.htm) and in the source code for MOBILE6.2 at Block Data BD05.) Given the differences in the EPA-recommended values and the value used to generate the initial 2002 base year inventory, the input files for Base F for *all* VISTAS areas were updated to reflect revised gasoline sulfur content assumptions.

Since the VISTAS NONROAD modeling is performed on a seasonal basis, and since gasoline sulfur content in RFG areas varies with the RFG season, seasonally-specific gasoline sulfur content values were estimated for use in RFG area modeling. In addition, 25 counties in Georgia are subject to a summertime gasoline sulfur limit of 150 ppmW, so that seasonal sulfur content estimates were also estimated for these counties. The initial 2002 base year NONROAD inventory (prepared by Pechan) for these Georgia counties was based on a year-round 339 ppmW gasoline sulfur content, but that oversight was corrected in the Base F 2002 base year inventory. Based on the seasonal definitions employed in the NONROAD model, monthly sulfur contents were averaged to estimate seasonal gasoline sulfur contents as follows:

Month/Season	RFG Areas	Conventional Gasoline Areas	Georgia Gasoline Control Areas
March	279 ppmW	279 ppmW	279 ppmW
April	279 ppmW	279 ppmW	279 ppmW
May	129 ppmW	279 ppmW	150 ppmW
Spring	229 ppmW	279 ppmW	236 ppmW
June	129 ppmW	279 ppmW	150 ppmW
July	129 ppmW	279 ppmW	150 ppmW
August	129 ppmW	279 ppmW	150 ppmW
Summer	129 ppmW	279 ppmW	150 ppmW
September	129 ppmW	279 ppmW	150 ppmW
October	279 ppmW	279 ppmW	279 ppmW
November	279 ppmW	279 ppmW	279 ppmW
Fall	229 ppmW	279 ppmW	236 ppmW
December	279 ppmW	279 ppmW	279 ppmW
January	279 ppmW	279 ppmW	279 ppmW
February	279 ppmW	279 ppmW	279 ppmW
Winter	279 ppmW	279 ppmW	279 ppmW

Note that the seasonal data are based on simple arithmetic averages and do not consider any monthly variation in activity (and fuel sales), and that the transition between summer and winter seasons is also not considered. Additionally, the summer fuel control season is treated as though it applies from May through September, while the summer RFG season actually ends on September 15 and the Georgia fuel control season does not officially begin until June 1. This treatment is consistent with the treatment of both fuel control programs in the VISTAS on-road vehicle modeling. Each of these influences will result in some error in the estimated sulfur content estimates, but it is expected that this error is small relative to the overall correction from a year-round sulfur content estimate of 339 ppmW.

All NONROAD modeling revisions made as part of the Base F inventory preparation process are presented in Table 1.3-2. Due to more involved updates in several areas, the number of NONROAD input files as well as sequence numbers used to represent these files was also updated in a few instances (as compared to the files used to create the initial 2002 VISTAS non-road inventory, as documented in the February 9, 2004 report "*Development of the VISTAS Draft 2002 Mobile Source Emission Inventory (February 2004 Version)*" as prepared by E.H. Pechan & Associates, Inc. These structural revisions are presented in Table 1.3-3, and are provided

solely for the benefit of NONROAD modelers as the indicated revisions have no impact on generated emission estimates.

Table 1.3-2 Summary of Base F NONROAD Modeling Revisions

State	Revisions Implemented
AL	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all counties and all seasons (all are conventional gasoline areas).
FL	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all counties and all seasons (all are conventional gasoline areas).
GA	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all seasons for conventional gasoline counties. (2) Gasoline sulfur content changed from 339 ppmW to 150 ppmW in the summer for all gasoline control counties. (3) Gasoline sulfur content changed from 339 ppmW to 236 ppmW in the spring and fall for all gasoline control counties. (4) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in the winter for all gasoline control counties. *Gasoline control counties: Barrow, Bartow, Butts, Carroll, Cherokee (a), Clayton (a), Cobb (a), Coweta (a), Dawson, De Kalb (a), Douglas (a), Fayette (a), Forsyth (a), Fulton (a), Gwinnett (a), Hall, Haralson, Henry (a), Jackson, Newton, Paulding (a), Pickens, Rockdale (a), Spalding, and Walton*
KY	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all seasons for conventional gasoline counties. (2) Gasoline sulfur content changed from 339 ppmW to 129 ppmW in the summer for all gasoline control counties. (3) Gasoline sulfur content changed from 339 ppmW to 229 ppmW in the spring and fall for all gasoline control counties. (4) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in the winter for all gasoline control counties. *Gasoline control counties: Boone, Bullitt (b), Campbell, Jefferson, Kenton, and Oldham (b)*
MS	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all counties and all seasons (all are conventional gasoline areas).
NC	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all counties and all seasons (all are conventional gasoline areas). (2) Utilize revised (i.e., local) allocation files for three equipment categories. (3) Utilize revised (i.e., local) seasonal activity data.
SC	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all counties and all seasons (all are conventional gasoline areas).
TN	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all counties and all seasons (all are conventional gasoline areas). (2) Gasoline Reid Vapor Pressure (RVP) values changed in accordance with local recommendations. (3) Temperature data changed in accordance with local recommendations. (4) Counties regrouped in accordance with local recommendations.

Table 1.3-2. Summary of Base F NONROAD Modeling Revisions (continued)

State	Revisions Implemented
VA	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all seasons for conventional gasoline counties. (2) Gasoline sulfur content changed from 339 ppmW to 129 ppmW in the summer for all gasoline control counties. (3) Gasoline sulfur content changed from 339 ppmW to 229 ppmW in the spring and fall for all gasoline control counties. (4) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in the winter for all gasoline control counties. (5) Gasoline RVP values changed in accordance with local recommendations. (6) Counties regrouped in accordance with local recommendations. (7) The control effectiveness for counties subject to Stage II controls revised to 77 percent in accordance with local recommendations. *Gasoline control counties: Arlington Co., Fairfax Co., Loudoun Co., Prince William Co., Stafford Co., Alexandria City, Fairfax City, Falls Church City, Manassas City, Manassas Park City, Chesterfield Co., Hanover Co., Henrico Co., Colonial Heights City, Hopewell City, Richmond City, James City, York Co., Chesapeake City, Hampton City, Newport News City, Norfolk City, Poquoson City, Portsmouth City, Suffolk City, Virginia Beach City, and Williamsburg City (c)*
WV	(1) Gasoline sulfur content changed from 339 ppmW to 279 ppmW in all counties and all seasons (all are conventional gasoline areas). (2) Continue to utilize local allocation files for nine equipment categories.

Notes:

(a) County is subject to local control currently, but is scheduled to join the RFG program in January 2005.
(b) Control area is a portion of the county, but modeling is performed as though the control applies countywide.
(c) The EPA also lists Charles City County as an RFG area, but local planners indicate that Charles City County is a conventional gasoline area and it is modeled as such.

Table 1.3-3 Base F NONROAD Input File Sequence and Structural Revisions

State	Initial 2002 Base Year Inventory Input File Sequence Numbers	Revised 2002 Inventory Input File Sequence Numbers	Reason(s) for Change	Number of Revised 2002 Inventory NONROAD Input Files
AL	01-08	01-08	No Structural Changes	32 (at 8 per season)
FL	09-10	09-10	No Structural Changes	8 (at 2 per season)
GA	11-13	11-13	No Structural Changes	12 (at 3 per season)
KY	14-22	14-22	No Structural Changes	36 (at 9 per season)
MS	48	48	No Structural Changes	4 (at 1 per season)
NC	23-25	23-25	No Structural Changes	12 (at 3 per season)
SC	26-32	26-32	No Structural Changes	28 (at 7 per season)
TN	33-34	33-34, 49-52	Counties Regrouped	24 (at 6 per season)
VA	35-43	35-38, 40-43	Counties Regrouped	32 (at 8 per season)
WV	44-47	44-47	No Structural Changes	16 (at 4 per season)
All	**01-48**	**01-38, 40-52**		**204 (at 51 per season)**

Note: (1) All files include internal revisions to reflect the data changes summarized in Table 1.3-3 above. This table is intended to present structural revisions that are of interest in assembling the NONROAD model input files into a complete VISTAS region inventory. The indicated revisions do not (in and of themselves) result in emission estimate changes.

(2) The NONROAD model imposes an eight digit input file name limit, so all input files for the revised 2002 base year inventory follow a modified naming convention to allow each to be distinguished from the input files for the initial 2002 base year inventory. For the initial 2002 base year inventory, the naming convention was:

ss02aaqq, where: ss = the two character State abbreviation,
aa = a two character season indicator as follows: AU = autumn, WI = winter, SP = spring, and SU = summer, and
qq = the two digit sequence number indicated above.

For the revised 2002 inventory, the naming convention was modified to:

ss02aFqq, where: ss = the two character State abbreviation,
a = a one character season indicator as follows: A = autumn, W = winter, S = spring, and X = summer, and
qq = the two digit sequence number indicated above.

Base G Revisions:

As described above, the primary modeling revision implemented for the Base G 2002 inventory was the use of the Final NONROAD2005 model (in place of the Base F use of Draft NONROAD2004). However, there were other minor revisions implemented for 13 Georgia counties and somewhat more significant revisions implemented for Tennessee. In Georgia, Stage II refueling control was assumed for 13 counties that previously were modeled as having no refueling control under Base F. In addition, to accommodate this Stage II change as well as forecast year changes in gasoline vapor pressure, corresponding changes in the structure and sequence of Georgia NONROAD input files were made. With the exception of the minor Stage II impacts, these structural and sequence changes have no impact on 2002 emission estimates, but allow for consistency between 2002 and forecast year input file structure and sequence. In Tennessee, more significant changes were implemented to gasoline vapor pressure assumptions, as well as similar minor changes in Stage II refueling control assumptions.

In accordance with instructions from Georgia regulators, Stage II refueling control was assumed in the following 13 Georgia counties at a control efficiency value of 81 percent for the Base G inventory:

> Cherokee, Clayton, Cobb, Coweta, DeKalb, Douglas, Fayette, Forsyth, Fulton, Gwinnett, Henry, Paulding, and Rockdale.

No Stage II control was assumed in these counties in prior inventories.

Tennessee regulators provided revised monthly values for gasoline vapor pressure. Based on the seasonal definitions employed in the NONROAD model, monthly vapor pressures were averaged to estimate seasonal vapor pressures as follows:

Month/Season	Nashville Area	Memphis Area	Remainder of Tennessee
March	13.5 psi	13.5 psi	13.5 psi
April	13.5 psi	13.5 psi	13.5 psi
May	9.0 psi	9.0 psi	9.0 psi
Spring	12.0 psi	12.0 psi	12.0 psi
June	7.8 psi	7.8 psi	9.0 psi
July	7.8 psi	7.8 psi	9.0 psi
August	7.8 psi	7.8 psi	9.0 psi
Summer	7.8 psi	7.8 psi	9.0 psi
September 1-15	7.8 psi	7.8 psi	9.0 psi
September 16-30	11.5 psi	11.5 psi	11.5 psi
October	13.5 psi	13.5 psi	13.5 psi
November	13.5 psi	13.5 psi	13.5 psi
Fall	12.2 psi	12.2 psi	12.4 psi
December	15.0 psi	15.0 psi	15.0 psi
January	15.0 psi	15.0 psi	15.0 psi
February	13.5 psi	13.5 psi	13.5 psi
Winter	14.5 psi	14.5 psi	14.5 psi

Note: The Nashville area consists of Davidson, Rutherford, Sumner, Williamson and Wilson counties, the Memphis area consists of Shelby County.

As with the Base F revisions, the seasonal data are based on simple arithmetic averages and do not consider any monthly variation in activity (and fuel sales), nor is the transition between summer and winter seasons considered. Additionally, a monthly average of the September 1-15 and September 16-30 data is calculated prior to averaging the September-November data to estimate a fall average vapor pressure, so that the month of September is weighted identically to the months of October and November.

Tennessee regulators also indicated that Stage II vapor recovery was not in effect in Shelby County, so the Base F NONROAD input files for the county (which assumed Stage II was in place) were revised accordingly.

All Base G NONROAD modeling revisions are presented in Table 1.3-4. As indicated above, the differentiation of inputs across previously grouped counties also required revision to the overall number and sequence of VISTAS NONROAD input files (as compared to the files used to create both the initial VISTAS non-road inventory, as documented in the February 9, 2004 report "*Development of the VISTAS Draft 2002 Mobile Source Emission Inventory (February 2004 Version)*" as prepared by E.H. Pechan & Associates, Inc., and the Base F revised inventory as

documented above. These structural revisions are presented in Table 1.3-5, and are provided solely for the benefit of NONROAD modelers as the indicated revisions have no impact on generated emission estimates.

Table 1.3-4 Summary of Base G NONROAD Modeling Revisions

State	Revisions Implemented
AL	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons.
FL	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons.
GA	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons. (2) Stage II refueling vapor recovery implemented in 13 counties at an efficiency of 81 percent. (3) Counties regrouped to accommodate base and forecast year data differentiations. *Stage II control counties: Cherokee, Clayton, Cobb, Coweta, De Kalb, Douglas, Fayette, Forsyth, Fulton, Gwinnett, Henry, Paulding, and Rockdale*
KY	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons.
MS	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons.
NC	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons. (2) Revert to default equipment allocation files for all equipment categories. (3) Utilize revised (i.e., local) seasonal activity data.
SC	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons.
TN	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons. (2) Gasoline RVP values changed in accordance with local recommendations. (3) Stage II vapor recovery eliminated from Shelby County modeling.
VA	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons.
WV	(1) Marine diesel sulfur content changed from 2500 ppmW to 2638 ppmW in all counties and seasons. (2) Revert to default equipment allocation files for all equipment categories.

Table 1.3-5 Spring 2006 NONROAD Input File Sequence and Structural Revisions

State	2002 Inventory Input File Sequence Numbers (Fall 2004)	2002 Inventory Input File Sequence Numbers (Spring 2006)	Reason(s) for Change	Number of Final 2002 Inventory NONROAD Input Files
AL	01-08	01-08	No Structural Changes	32 (at 8 per season)
FL	09-10	09-10	No Structural Changes	8 (at 2 per season)
GA	11-13	11-13, 53-54	Counties Regrouped	20 (at 5 per season)
KY	14-22	14-22	No Structural Changes	36 (at 9 per season)
MS	48	48	No Structural Changes	4 (at 1 per season)
NC	23-25	23-25	No Structural Changes	12 (at 3 per season)
SC	26-32	26-32	No Structural Changes	28 (at 7 per season)
TN	33-34, 49-52	33-34, 49-52	No Structural Changes	24 (at 6 per season)
VA	35-38, 40-43	35-38, 40-43	No Structural Changes	32 (at 8 per season)
WV	44-47	44-47	No Structural Changes	16 (at 4 per season)
All	**01-38, 40-52**	**01-38, 40-54**		**212 (at 53 per season)**

Note: (1) All files include internal revisions to reflect the data changes summarized in Table 1.3-5 above. This table is intended to present structural revisions that are of interest in assembling the NONROAD model input files into a complete VISTAS region inventory. The indicated revisions do not (in and of themselves) result in emission estimate changes.

(2) The NONROAD model imposes an eight digit input file name limit, so all input files for the revised 2002 base year inventory follow a modified naming convention to allow each to be distinguished from the input files for the initial 2002 and fall 2004-revised 2002 base year inventory. For the initial 2002 base year inventory, the naming convention was:

ss02aaqq, where: ss = the two character State abbreviation,
aa = a two character season indicator as follows: AU = autumn, WI = winter, SP = spring, and SU = summer, and
qq = the two digit sequence number indicated above.

For the fall 2004-revised 2002 inventory, the naming convention was modified to:

ss02aFqq, where: ss = the two character State abbreviation,
a = a one character season indicator as follows: A = autumn, W = winter, S = spring, and X = summer, and
qq = the two digit sequence number indicated above.

For the spring 2006-revised 2002 inventory, the naming convention was modified to:

ss02aCqq, where: ss = the two character State abbreviation,
a = a one character season indicator as follows: A = autumn, W = winter, S = spring, and X = summer, and
qq = the two digit sequence number indicated above.

1.3.2.2 Emissions from Commercial Marine Vessels, Locomotives, and Airplanes

An initial 2002 base year emissions inventory for aircraft, locomotives, and commercial marine vessels (CMV) was prepared for VISTAS in early 2004. The methods and data used to develop the inventory are presented in a February 9, 2004 report "*Development of the VISTAS Draft 2002 Mobile Source Emission Inventory (February 2004 Version)*" as prepared by E.H. Pechan & Associates, Inc. A summary of the initial 2002 base year emissions inventory is presented in Table 1.3-6. Except as otherwise stated below, all aspects of the preparation methodology continue to apply to the Base F and Base G emission inventories.

Revisions to the initial 2002 emissions inventory (prepared by Pechan) were implemented to ensure that the latest State and local data were incorporated as well as to correct an overestimation of PM emissions from aircraft. Revisions were actually implemented in two stages. An initial set of revisions was implemented in the fall of 2004. Those revisions constitute the Base F inventory. These were followed by a second set of revisions in 2006, which constitute the Base G inventory. To accurately document the combined effects of both sets of revisions, each set is discussed separately below. Unless otherwise indicated, all revisions implemented for Base F were carried directly into the Base G revision process without change. Thus, the inventories that resulted from the Base F revisions served as the starting point for the Base G revisions.

Base F Revisions:

Revisions to the initial 2002 base year emissions inventory were implemented to ensure that the latest State and local data were incorporated as well as to correct an overestimation of PM emissions from aircraft. Seven of the ten VISTAS States provided revised inventory data in the form of emissions reported to the EPA under the CERR. States providing CERR data were Alabama, Georgia, Mississippi, North Carolina, Tennessee (excluding Davidson, Hamilton, Knox, and Shelby Counties), Virginia, and West Virginia.

In many cases, the CERR data were only marginally different than the initial 2002 base year inventory data, but there were several instances where significant updates were evident. The remaining three VISTAS States (Florida, Kentucky, and South Carolina), plus Davidson, Hamilton, Knox, and Shelby counties in Tennessee, indicated that the initial 2002 VISTAS inventory continued to reflect the most recent data available. Florida did provide updated aircraft emissions data for one county (Miami-Dade) and these data were incorporated into the Base F 2002 inventory as described below.

Since several States recommended retaining the initial 2002 base year inventory data for Base F, the initial step toward revising the 2002 inventory consisted of modifying the estimated aircraft PM emissions of the initial inventory. The overestimation of aircraft PM became evident shortly

after the release of the initial 2002 base year inventory, when it was determined that VISTAS region airports would constitute the top seven, and 11 of the top 15, PM sources in the nation. Moreover, PM emissions for one airport (Miami International) were a full order of magnitude larger than *all* other modeled elemental carbon PM emission sources. In addition, unexpected relationships across airports were also observed, with emissions for Atlanta's Hartsfield International being substantially less than those of Miami International, even though Atlanta handles over twice as many aircraft operations annually. Given the pervasiveness of this problem, and since the CERR data submitted by States was based on the initial 2002 VISTAS inventory data, aircraft PM emissions for the entire VISTAS region were recalculated.

Table 1.3-6 Initial 2002 Base Year Aircraft, Locomotive, and Non-Recreational Marine Emissions as Reported in February 2004 Pechan Report (annual tons)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	3,787	175	688	475	17	196
	FL	28,518	11,955	46,352	31,983	1,050	3,703
	GA	3,175	992	3,919	2,704	94	353
	KY	2,666	657	2,597	1,792	63	263
	MS	1,593	140	553	381	13	96
	NC	6,088	1,548	6,115	4,219	148	613
	SC	6,505	515	452	312	88	863
	TN	6,854	2,665	7,986	5,510	225	920
	VA	17,676	5,607	14,476	9,988	234	3,229
	WV	1,178	78	310	214	8	66
	Total	**78,040**	**24,332**	**83,448**	**57,578**	**1,940**	**10,302**
Commercial Marine (2280)	AL	1,195	9,217	917	843	3,337	736
	FL	5,888	44,817	1,936	1,781	6,683	1,409
	GA	1,038	7,874	334	307	1,173	246
	KY	6,607	50,267	2,246	2,066	9,608	1,569
	MS	5,687	43,233	1,903	1,750	7,719	1,351
	NC	599	4,547	193	178	690	142
	SC	1,067	8,100	343	316	1,205	253
	TN	4,129	31,397	1,390	1,278	5,753	980
	VA	1,198	3,426	929	855	3,258	596
	WV	2,094	15,882	668	614	720	497
	Total	**29,503**	**218,760**	**10,858**	**9,989**	**40,146**	**7,779**
Military Marine (2283)	VA	136	387	28	26	30	59
	Total	**136**	**387**	**28**	**26**	**30**	**59**
Locomotives (2285)	AL	3,490	26,339	592	533	1,446	1,354
	FL	1,006	9,969	247	222	605	404
	GA	2,654	26,733	664	598	1,622	1,059
	KY	2,166	21,811	542	488	1,321	867
	MS	2,302	23,267	578	520	1,429	899
	NC	1,638	16,502	410	369	1,001	654
	SC	1,160	11,690	291	261	710	462
	TN	4,530	44,793	1,110	999	2,689	1,805
	VA	1,928	19,334	1,407	1,266	3,443	798
	WV	1,105	11,150	277	249	681	436
	Total	**21,980**	**211,588**	**6,118**	**5,505**	**14,947**	**8,738**
Grand Total		**129,659**	**455,067**	**100,452**	**73,099**	**57,062**	**26,877**

Aircraft do emit PM while operating. However, official EPA inventory procedures for aircraft generally do not include PM emission factors and, therefore, aircraft PM is generally erroneously reported as zero. In an effort to overcome this deficiency, the developers of the initial VISTAS 2002 base year aircraft inventory (Pechan) estimated PM emission rates for aircraft using estimated NO_x emissions and an unreported PM-to-NO_x ratio (i.e., PM = NO_x times a PM-to-NO_x ratio). According to the initial 2002 base year inventory documentation, this approach was applied only to commercial aircraft NO_x, but a review of that inventory indicates that the technique was also applied to military, general aviation, and air taxi aircraft in many, but not all, instances. Although there is nothing inherently incorrect with this approach, the accuracy and inconsistent application of the assumed PM-to-NO_x ratio results in grossly overestimated aircraft PM.

Through examination of the initial 2002 base year aircraft inventory (prepared by E.H. Pechan and Associates, Inc.), it is apparent that the commercial aircraft PM-to-NO_x ratio used to generate PM emission estimates was approximately equal to 3.95 (i.e., PM = NO_x times 3.95). While the majority of observed commercial aircraft PM-to-NO_x ratios in that inventory are equal to 3.95, a few range as low as 3.00. If all aircraft estimates are included (i.e., commercial plus military, general aviation, and air taxi), observed PM-to-NO_x ratios range from 0 to 123.0, and average 3.43 as illustrated in Table 1.3-7

Table 1.3-7 PM-to-NO_x Ratios by Aircraft Type In Initial 2002 Base Year Inventory.

Aircraft Type	Average PM-to-NO_x	Range of PM-to-NO_x	Average $PM_{2.5}$ / PM_{10}	Range of $PM_{2.5}$ / PM_{10}
Undefined (1)	0.046	0-0.062	0.690	0.690-0.690
Military	0.073	0-92.3	0.688	0.333-1.000
Commercial	3.953	3.00-3.953	0.690	0.667-0.696
General Aviation	2.059	0-9.00	0.689	0.500-1.000
Air Taxi	2.734	0-123.0	0.690	0.500-1.000
Aggregate	3.427	0-123.0	0.690	0.333-1.000

Note: (1) Two counties report aircraft emissions as SCC 2275000000 “all aircraft.”

As indicated, the aggregate PM-to-NO_x ratio is similar in magnitude to the ratio for commercial aircraft. This results from the dominant nature of commercial aircraft NO_x emissions relative to NO_x from other aircraft types. It is surmised that ratios that deviate from 3.95 are based on PM emission estimates generated by local planners, which were retained without change in the PM estimation process (although a considerable number of unexplained “zero PM” records also exist

in the initial 2002 base year inventory dataset). Regardless, based on previous statistical analyses performed in support of aircraft emissions inventory development outside the VISTAS region, a PM-to-NO_x ratio of 3.95 is too large by over an order of magnitude.

In analyses performed for the Tucson, Arizona planning area, PM-to-NO_x ratios for aircraft over a standard aircraft landing and takeoff (LTO) cycle are shown in Table 1.3-8. Data for this table is taken from "Emissions Inventories for the Tucson Air Planning Area, Volume I., Study Description and Results," prepared for the Pima Association of Governments, Tucson, AZ, November 2001. Pages 4-40 through 4-42 of that report, which document the statistical derivation of these ratios, are included in this report as Appendix E.

Table 1.3-8 Tucson, AZ PM-to-NO_x Ratios by Aircraft Type.

Aircraft Type	PM-to-NO_x
Commercial Aircraft	0.26
Military Aircraft	0.88
Air Taxi Aircraft	0.50
General Aviation Aircraft	1.90

Note:

The PM and NO_x emission estimates presented in the Tucson study are for local aircraft operating mode times. For this work, emission estimates for Tucson were recalculated for a standard LTO cycle, so that the ratios presented are applicable to the standard LTO cycle and not a Tucson-specific cycle. Thus, the ratios presented herein vary somewhat from those associated with the emission estimates presented in the Tucson study report.

In reviewing these data, it should be considered that they apply to a standard (i.e., EPA-defined) commercial aircraft LTO cycle.[2] Aircraft PM-to-NO_x ratios vary with operating mode, so that aircraft at airports with mode times that differ from the standard cycle will exhibit varying ratios. However, conducting an airport-specific analysis for all airports in the VISTAS region was beyond the scope of this work. While local PM-to-NO_x ratios could vary somewhat from the indicated standard cycle ratios, any error due to this variation will be significantly less than the order of magnitude error associated with the 3.95 commercial aircraft ratio used for the initial 2002 base year inventory.

It should be recognized that while the Tucson area is far removed from the VISTAS region, the data analyzed to generate the PM-to-NO_x ratios is standard aircraft emission factor data routinely employed for inventory purposes throughout the United States (as encoded in models such as the

[2] As defined in *AP-42, Compilation of Air Pollutant Emission Factors, Volume II, Mobile Sources, a standard commercial aircraft LTO cycle consists of 4 minutes of approach time, 26 minutes of taxi (7 minutes in plus 19 minutes out), 0.7 minutes of takeoff, and 2.2 minutes of climbout time (approach and climbout times being based on a 3000 foot mixing height).*

Federal Aviation Administration's Emissions Data Management Systems [EDMS]). With the exception of aircraft operating conditions, there are no inherent geographic implications associated with the use of data from the Tucson study. As indicated above, issues associated with local operating conditions have been eliminated by recalculating the Tucson study ratios for a standard LTO cycle.

To implement the revised PM-to-NO_x ratios in the Base F inventory, *all* aircraft PM records were removed from the initial 2002 base year inventory (prepared by Pechan). This includes records for which local planners may have estimated PM emissions. This approach was taken for two reasons. First, there is no way to distinguish which records may have been generated by local planners. Second, the data available to local planners may be no better than that used to generate the presented PM-to-NO_x ratio data, so the consistent application of these data to the entire VISTAS region was determined to be the most appropriate approach to generating consistent inventories throughout the region. In undertaking this removal, it became apparent that there was an imbalance in the aircraft NO_x and PM records in the initial 2002 base year inventory. Whereas there were 1,531 NO_x records in the NIF emission data sets for this source category, there were only 1,212 PM records. The imbalance was distributed between three States, South Carolina, Tennessee, and Virginia as follows:

Table 1.3-9 Non-Corresponding Aircraft Emissions Records

Aircraft NO_x records with no corresponding PM record:

Aircraft Type	South Carolina	Virginia	Total
Military Aircraft	8	100	108
General Aviation Aircraft	14	94	108
Air Taxi Aircraft	5	99	104
Aggregate	27	293	320

Aircraft PM records with no corresponding NO_x record:

Aircraft Type	Tennessee	Total
Air Taxi Aircraft	1	1
Aggregate	1	1

The unmatched PM record was for Hamilton County (Chattanooga), Tennessee and when removed, was not replaced since there was no corresponding NO_x record with which to estimate revised PM emissions. It is unclear how this orphaned record originated, but clearly there can be no air taxi PM emissions without other combustion-related emissions. Thus, the removal of the PM_{10} and $PM_{2.5}$ records for Hamilton County permanently reduced the overall size of the 2002 initial base year inventory database used as a starting point for Base F by two records.

Of the 320 unmatched NO_x records, 269 were records for which the reported emission rate was zero. Therefore, even though associated PM records were missing, the overall inventory was not affected. However, the 51 missing records for which NO_x emissions were non-zero, did impact PM estimates for the overall inventory.

Replacement PM_{10} records were calculated for all aircraft NO_x records using the PM-to-NO_x ratios presented above. Aircraft type-specific ratios were utilized in all cases, except for two counties where aircraft emissions were reported under the generic aircraft SCC 2275000000. For these counties (Palm Beach County, Florida and Davidson County, Tennessee), the commercial aircraft PM-to-NO_x ratio was applied since both contain commercial airports (Palm Beach International and Nashville International).

Replacement aircraft $PM_{2.5}$ records were also developed. The initial 2002 base year inventory assumed that aircraft $PM_{2.5}$ was 69 percent of aircraft PM_{10}. The origin of this fraction is not clear, but it is very low for combustion related PM. The majority of internal combustion engine related PM is typically 1 micron or smaller ($PM_{1.0}$), so that typical internal combustion engine $PM_{2.5}$ fractions approach 100 percent. For example, the EPA NONROAD model assumes 92 percent for gasoline engine particulate and 97 percent for diesel engine particulate. Based on recent correspondence from the EPA, it appears that the agency is preparing to recommend a $PM_{2.5}$ fraction of 98 percent for aircraft. (August 12, 2004 e-mail correspondence from U.S. EPA to Gregory Stella of Alpine Geophysics.) This is substantially more consistent with expectations based on emissions test data for other internal combustion engine sources and was used as the basis for the recalculated aircraft $PM_{2.5}$ emission estimates in the Base F inventory.

Although a substantial portion of the initial 2002 base year inventory was ultimately replaced with data prepared by State and local planners under CERR requirements in developing the Base F inventory, it was necessary to first revise the initial 2002 base year aircraft inventory as described so that records extracted from the inventory for areas not supplying CERR data for the Base F update would be accurate. Therefore, in *no case* is the aggregated State data reported for the Base F inventory identical to that of the initial 2002 base year inventory. Even areas relying on the initial 2002 base year inventory will reflect updates in Base F due to changes in emissions of PM_{10} and $PM_{2.5}$ from aircraft.

Table 1.3-10 presents the updated initial 2002 base year inventory estimates. These estimates do not reflect any changes related to modifications made to incorporate the CERR data, but instead indicate the impacts associated solely with the recalculation of aircraft PM emissions alone to apply the more appropriate PM to NO_x ratios. Table 1.3-11 presents a summary of the net impacts of these changes, where an over 90 percent reduction in aircraft PM is observed for all VISTAS areas except South Carolina and Virginia. The reasons for the lesser changes in these two States is that the overall aircraft NO_x inventories for both include a large share of military

aircraft NO_x to which no (or very low) particulate estimates were assigned in the initial 2002 base year inventory. Since these operations are assigned non-zero PM emissions under the revised approach, the increase in military aircraft PM offsets a portion of the reduction in commercial aircraft PM. In Virginia, zero (or near zero) PM military operations were responsible for about 35 percent of total aircraft NO_x, while the corresponding fraction in South Carolina was almost 70 percent. As indicated, aggregate aircraft, locomotive, and commercial marine vessel PM is 70-75 percent lower in the updated 2002 base year inventory.

Table 1.3-10 Initial 2002 Base Year Aircraft, Locomotive, and Non-Recreational Marine Emissions with Modified Aircraft PM Emission Rates (annual tons)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	3,787	175	64	62	17	196
	FL	28,518	11,955	3,193	3,129	1,050	3,703
	GA	3,175	992	269	264	94	353
	KY	2,666	657	179	175	63	263
	MS	1,593	140	44	43	13	96
	NC	6,088	1,548	419	411	148	613
	SC	6,505	515	409	401	88	863
	TN	6,854	2,665	707	692	225	920
	VA	17,676	5,607	2,722	2,667	234	3,229
	WV	1,178	78	25	24	8	66
	Total	**78,040**	**24,332**	**8,030**	**7,870**	**1,940**	**10,302**
Commercial Marine (2280)	AL	1,195	9,217	917	843	3,337	736
	FL	5,888	44,817	1,936	1,781	6,683	1,409
	GA	1,038	7,874	334	307	1,173	246
	KY	6,607	50,267	2,246	2,066	9,608	1,569
	MS	5,687	43,233	1,903	1,750	7,719	1,351
	NC	599	4,547	193	178	690	142
	SC	1,067	8,100	343	316	1,205	253
	TN	4,129	31,397	1,390	1,278	5,753	980
	VA	1,198	3,426	929	855	3,258	596
	WV	2,094	15,882	668	614	720	497
	Total	**29,503**	**218,760**	**10,858**	**9,989**	**40,146**	**7,779**
Military Marine (2283)	VA	136	387	28	26	30	59
	Total	136	387	28	26	30	59
Locomotives (2285)	AL	3,490	26,339	592	533	1,446	1,354
	FL	1,006	9,969	247	222	605	404
	GA	2,654	26,733	664	598	1,622	1,059
	KY	2,166	21,811	542	488	1,321	867
	MS	2,302	23,267	578	520	1,429	899
	NC	1,638	16,502	410	369	1,001	654
	SC	1,160	11,690	291	261	710	462
	TN	4,530	44,793	1,110	999	2,689	1,805
	VA	1,928	19,334	1,407	1,266	3,443	798
	WV	1,105	11,150	277	249	681	436
	Total	**21,980**	**211,588**	**6,118**	**5,505**	**14,947**	**8,738**
Grand Total		**129,659**	**455,067**	**25,034**	**23,390**	**57,062**	**26,877**

Table 1.3-11 Change in Initial 2002 Base Year Emissions due to Aircraft PM Emission Rate Modifications.

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	0%	0%	-91%	-87%	0%	0%
	FL	0%	0%	-93%	-90%	0%	0%
	GA	0%	0%	-93%	-90%	0%	0%
	KY	0%	0%	-93%	-90%	0%	0%
	MS	0%	0%	-92%	-89%	0%	0%
	NC	0%	0%	-93%	-90%	0%	0%
	SC	0%	0%	-9%	+29%	0%	0%
	TN	0%	0%	-91%	-87%	0%	0%
	VA	0%	0%	-81%	-73%	0%	0%
	WV	0%	0%	-92%	-89%	0%	0%
	Total	**0%**	**0%**	**-90%**	**-86%**	**0%**	**0%**
Commercial Marine (2280)	AL	0%	0%	0%	0%	0%	0%
	FL	0%	0%	0%	0%	0%	0%
	GA	0%	0%	0%	0%	0%	0%
	KY	0%	0%	0%	0%	0%	0%
	MS	0%	0%	0%	0%	0%	0%
	NC	0%	0%	0%	0%	0%	0%
	SC	0%	0%	0%	0%	0%	0%
	TN	0%	0%	0%	0%	0%	0%
	VA	0%	0%	0%	0%	0%	0%
	WV	0%	0%	0%	0%	0%	0%
	Total	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Military Marine (2283)	VA	0%	0%	0%	0%	0%	0%
	Total	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Locomotives (2285)	AL	0%	0%	0%	0%	0%	0%
	FL	0%	0%	0%	0%	0%	0%
	GA	0%	0%	0%	0%	0%	0%
	KY	0%	0%	0%	0%	0%	0%
	MS	0%	0%	0%	0%	0%	0%
	NC	0%	0%	0%	0%	0%	0%
	SC	0%	0%	0%	0%	0%	0%
	TN	0%	0%	0%	0%	0%	0%
	VA	0%	0%	0%	0%	0%	0%
	WV	0%	0%	0%	0%	0%	0%
	Total	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Grand Total		**0%**	**0%**	**-75%**	**-68%**	**0%**	**0%**

As indicated above, for the Base F 2002 base year inventory, data for all or portions of seven VISTAS States were replaced with corresponding data from recent (as of the fall of 2004) CERR submissions for 2002. Before replacing these data, however, an analysis of the CERR data was performed to ensure consistency with VISTAS inventory methods. It should perhaps also be noted that three of the CERR datasets provided for the Base F 2002 base year inventory (specifically those for Tennessee, Virginia, and West Virginia) included both annual and daily emissions data. Only the annual data were used. Daily values were removed.

Several important observations resulted from this analysis. First, it was clear that all of the CERR data continued to rely on the inaccurate aircraft PM estimation approach employed for the initial 2002 base year inventory. Therefore, an identical aircraft PM replacement procedure as described above for updating the initial 2002 base year inventory was undertaken for CERR supplied data. As a result, the CERR data for *all* VISTAS States has been modified for inclusion in the Base F 2002 VISTAS base year inventory due to PM replacement procedures.

As was the case with the initial VISTAS 2002 base year inventory, there were a substantial number of aircraft NO_x records without corresponding PM records, so that the number of recalculated PM records added to the CERR dataset is greater than the number of PM records removed. The aggregated CERR inventory data, reflecting data for all or parts of seven States, consisted of 13,656 records, of which 1,211 were aircraft NO_x records. However, the number of corresponding aircraft PM records was 662 (662 PM_{10} records and 662 $PM_{2.5}$ records). This imbalance was distributed as follows:

Table 1.3-12 CERR Aircraft NO_x Records with No Corresponding PM Record.

Aircraft Type	Georgia	Tennessee	Virginia	Total
Military Aircraft			136	136
Commercial Aircraft		4	136	140
General Aviation Aircraft	1		136	137
Air Taxi Aircraft			136	136
Aggregate	**1**	**4**	**544**	**549**

From this tabulation, it is clear that virtually the entire imbalance is associated with the Virginia CERR submission, with minor imbalances in Georgia and Tennessee. Of the 549 unmatched NO_x records, 461 were records for which the reported emission rate was zero. Therefore, even though the associated PM records were missing, the overall inventory was not affected. However, the 88 missing records for which NO_x emissions were non-zero do impact PM emission estimates for the overall inventory.

Replacement aircraft PM records (both PM_{10} and $PM_{2.5}$) were generated for the CERR dataset using procedures identical to those described above for the updated initial 2002 base year inventory.

Further analysis revealed that the CERR data for Virginia included only VOC, CO, and NO_x emissions for all aircraft, locomotives, and non-recreational marine vessels. Since SO_2, PM_{10}, and $PM_{2.5}$ records are included in the 2002 VISTAS inventory, an estimation method was developed for these emission species and applied to the Virginia CERR data. For PM, the

developed methodology was only employed for locomotive and marine vessel data since aircraft PM was estimated using the PM-to-NO_x ratio methodology described above.

Consideration was given to simply adding the Virginia SO_2 and non-aircraft PM records from the initial 2002 VISTAS inventory dataset, but it is very unlikely that either the source distribution or associated emission rates are identical across the CERR and initial VISTAS inventories. This was confirmed through a comparative analysis of dataset CO records. Therefore, an estimation methodology was developed using Virginia source-specific SO_2/CO, PM_{10}/CO, and $PM_{2.5}$/PM_{10} ratios from the initial 2002 base year VISTAS inventory. The calculated ratios were then applied to the source-specific CERR CO emission estimates to derive associated source-specific SO_2, PM_{10}, and $PM_{2.5}$ emissions for the Base F inventory.

Initially, the development of the emissions ratios from the initial 2002 base year inventory was performed at the State (i.e., Virginia), county, and SCC level of detail. However, it readily became clear that there were substantial inconsistencies in ratios for identical SCCs across counties. For example, in one county, the SO_2/CO ratio might be 0.2, while in the next county it would be 2.0. Since the sources in question are virtually identical (e.g., diesel locomotives) and since the fueling infrastructure for these large non-road equipment sources is regional as opposed to local in nature, such variations in emission rates are not realistic. Therefore, a more aggregated approach was employed in which SCC-specific emission ratios were developed for the State as a whole. Through this approach county-to-county variation in emission ratios is eliminated, but the underlying variation in CO emissions does continue to influence the resulting aggregate emission estimates. The applied emission ratios are as follows:

Table 1.3-13 Calculated Emission Ratios for VA.

Source	SCC	SO_2/CO	PM_{10}/CO	$PM_{2.5}$/CO	$PM_{2.5}$/PM_{10}
Military Aircraft	2275001000	0.0215	*Emissions estimated using PM-to-NO_x ratios as described previously.*		
Commercial Aircraft	2275020000	0.3292			
General Aviation Aircraft	2275050000	0.0002			
Air Taxi Aircraft	2275060000	0.0015			
Aircraft Refueling	2275900000	0.0000	0.0000	0.0000	
Diesel Commercial Marine	2280002000	0.3697	0.3434	0.3157	0.92
Residual Commercial Marine	2280003000	0.3697	0.3434	0.3157	0.92
Diesel Military Marine	2283002000	0.2422	0.2248	0.2068	0.92
Line Haul Locomotives	2285002005	3.2757	1.2999	1.1696	0.90
Yard Locomotives	2285002010	2.2908	1.2461	1.1205	0.90

It is important to recognize that the inconsistency of emissions ratios across Virginia counties for sources of virtually identical design, which utilize a regional rather than local fueling infrastructure, has potential implications for other VISTAS States. There is no immediately obvious reason to believe that such inconsistencies would be isolated to Virginia.

One final revision to the CERR dataset was undertaken as part of the Base F effort, and that was the removal of two records for unpaved airstrip particulate (SCC 2275085000) in Alabama. Otherwise identical records for these emissions were reported both in terms of filterable and primary particulate. The filterable particulate records were removed as all other particulate emissions in the VISTAS inventories are in terms of primary particulate. It is also perhaps worth noting that a series of aircraft refueling records (SCC 2275900000) for Virginia were left in place, even through typically such emissions would be reported under SCC 2501080XXX in the area source inventory. If additional VISTAS aircraft refueling emissions are reported under SCC 2501080XXX, then it may be desirable to recode these records.

Finally, data for areas of the VISTAS region not represented in the CERR dataset were added to the CERR data by extracting the appropriate records from the initial 2002 base year inventory (with revisions for aircraft PM to NO_x ratios). Specifically, records applicable to the States of Florida, Kentucky, South Carolina, and the Tennessee counties of Davidson, Hamilton, Knox, and Shelby were extracted from the revised initial 2002 inventory and added to the CERR dataset to establish the 2002 Base F inventory.

Following this aggregation, one last dataset revision was implemented to complete the development of the 2002 Base F inventory. As indicated in the introduction of this section, the initial 2002 base year emission estimates for Miami International Airport were determined to be excessive. Although the reason for this inaccuracy was not apparent, revised estimates for aircraft emissions in Miami-Dade County were obtained from Florida planners and used to overwrite the erroneous estimates. (Aircraft emission estimates were provided in an August 10, 2004 e-mail transmittal from Bruce Coward of Miami-Dade County to Martin Costello of the Florida Department of Environmental Protection.)

Table 1.3-14 presents a summary of the resulting Base F VISTAS 2002 base year inventory estimates for aircraft, locomotives, and non-recreational marine vessels. Table 1.3-15 provides a comparison of the Base F 2002 base year inventory estimates to those of the initial 2002 base year inventory. As indicated, total emissions for VOC, CO, NO_x, and SO_2 are generally within 10 percent, but final PM emissions are reduced by 70-80 percent due to the approximate 90 percent reductions in aircraft PM estimates. In addition, the significant changes in Georgia aircraft emissions are due to the CERR correction of Atlanta Hartsfield International Airport emissions, which were significantly underestimated in the initial 2002 base year inventory. The

reduction in Florida aircraft emissions due to the correction of Miami International estimates is also apparent.

Lastly, Table 1.3-16 provides a direct comparison of emission estimates from the initial and Base F 2002 base year inventories for all 16 VISTAS region airports with estimated annual aircraft NO_x emissions of 200 tons or greater (as identified at the conclusion of the Base F revisions).[3] The table entries are sorted in order of decreasing NO_x and once again, the dramatic reduction in PM emissions is evident. However, in addition, the appropriate reversal of the relationship between Atlanta's Hartsfield and Miami International Airport is also depicted. As a rough method of quality assurance, Table 1.3-15 also includes a *gross* estimate of expected airport NO_x emissions using detailed NO_x estimates developed for Tucson International Airport in conjunction with the ratio of local to Tucson LTOs. (The Tucson NO_x estimates are revised to reflect a standard LTO cycle rather than the Tucson-specific LTO cycle. This should provide for a more realistic comparison to VISTAS estimates.) This is not meant to serve as anything other than a crude indicator of the propriety of the developed VISTAS estimates, and it is clear that the range of estimated-to-expected NO_x emissions has been substantially narrowed in the Base F 2002 base year inventory. Whereas estimated-to-expected ratios varied from about 0.2 to over 3.5 in the initial 2002 base year inventory, the range of variation is tightened on both ends, from about 0.5 to 1.75 for the Base F 2002 base year inventory. In effect, all estimates are now within a factor of two of the expected estimates, which is quite reasonable given likely variation in local and standard LTO cycles and variations in aircraft fleet mix across airports.

It is perhaps important to note that some shifting in county emissions assignments is evident between the initial and Base F 2002 base year aircraft inventories. For example, for the initial 2002 base year inventory, Atlanta Hartsfield estimates were assigned to Fulton County (FIP 13121), while they are assigned to Clayton County (FIP 13063) for the Base F 2002 base year inventory. Similarly, Dulles International Airport emissions were assigned solely to Fairfax County, Virginia (FIP 51059) in the initial 2002 base year inventory, but are split between Fairfax and Loudoun County (FIP 51107) for Base F. Such shifts reflect local planner decision-making and are not an artifact of the revisions described above.

[3] Subsequent revisions performed for Base G result in the addition of the Cincinnati/Northern Kentucky International Airport to the group of airports with aircraft operations generating at least 200 tons of NO_x. These revisions are discussed below, including the addition of an appropriately modified version of the aircraft emissions table.

Table 1.3-14 Base F 2002 Base Year Aircraft, Locomotive, and Non-Recreational Marine Emissions (tons/year)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	3,787	175	226	87	17	196
	FL	25,431	8,891	2,424	2,375	800	3,658
	GA	6,622	5,372	1,475	1,446	451	443
	KY	2,666	657	179	175	63	263
	MS	1,593	140	44	43	13	96
	NC	6,088	1,548	419	411	148	613
	SC	6,505	515	409	401	88	863
	TN	7,251	2,766	734	719	235	943
	VA	9,763	2,756	1,137	1,115	786	2,529
	WV	1,178	78	25	24	8	66
	Total	**70,884**	**22,899**	**7,072**	**6,797**	**2,607**	**9,670**
Commercial Marine (2280)	AL	1,196	9,218	917	844	3,337	737
	FL	5,888	44,817	1,936	1,781	6,683	1,409
	GA	1,038	7,875	334	307	1,173	246
	KY	6,607	50,267	2,246	2,066	9,608	1,569
	MS	5,688	43,233	1,903	1,751	7,719	1,351
	NC	599	4,547	193	178	690	142
	SC	1,067	8,100	343	316	1,205	253
	TN	3,624	27,555	1,217	1,120	4,974	860
	VA	972	2,775	334	307	359	483
	WV	1,528	11,586	487	448	525	362
	Total	**28,207**	**209,972**	**9,911**	**9,118**	**36,275**	**7,413**
Military Marine (2283)	VA	110	313	25	23	27	48
	Total	**110**	**313**	**25**	**23**	**27**	**48**
Locomotives (2285)	AL	3,490	26,339	592	533	1,446	1,354
	FL	1,006	9,969	247	222	605	404
	GA	2,725	27,453	682	614	1,667	1,086
	KY	2,166	21,811	542	488	1,321	867
	MS	2,302	23,267	578	520	1,429	899
	NC	1,638	16,502	410	369	1,001	654
	SC	1,160	11,690	291	261	710	462
	TN	2,626	25,627	633	570	1,439	1,041
	VA	1,186	11,882	1,529	1,375	3,641	492
	WV	1,311	13,224	329	296	808	517
	Total	**19,611**	**187,764**	**5,833**	**5,248**	**14,066**	**7,777**
Grand Total		**118,812**	**420,948**	**22,841**	**21,186**	**52,976**	**24,908**

Table 1.3-15 Change in 2002 Emissions, Base F Inventory Relative to Initial Inventory

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	0%	0%	-67%	-82%	0%	0%
	FL	-11%	-26%	-95%	-93%	-24%	-1%
	GA	+109%	+442%	-62%	-47%	+379%	+26%
	KY	0%	0%	-93%	-90%	0%	0%
	MS	0%	0%	-92%	-89%	0%	0%
	NC	0%	0%	-93%	-90%	0%	0%
	SC	0%	0%	-9%	+29%	0%	0%
	TN	+6%	+4%	-91%	-87%	+4%	+2%
	VA	-45%	-51%	-92%	-89%	+236%	-22%
	WV	0%	0%	-92%	-89%	0%	0%
	Total	**-9%**	**-6%**	**-92%**	**-88%**	**+34%**	**-6%**
Commercial Marine (2280)	AL	+0%	+0%	+0%	+0%	+0%	+0%
	FL	0%	0%	0%	0%	0%	0%
	GA	+0%	+0%	+0%	+0%	+0%	+0%
	KY	0%	0%	0%	0%	0%	0%
	MS	+0%	+0%	+0%	+0%	+0%	+0%
	NC	+0%	+0%	+0%	+0%	+0%	+0%
	SC	0%	0%	0%	0%	0%	0%
	TN	-12%	-12%	-12%	-12%	-14%	-12%
	VA	-19%	-19%	-64%	-64%	-89%	-19%
	WV	-27%	-27%	-27%	-27%	-27%	-27%
	Total	**-4%**	**-4%**	**-9%**	**-9%**	**-10%**	**-5%**
Military Marine (2283)	VA	-19%	-19%	-12%	-12%	-12%	-19%
	Total	**-19%**	**-19%**	**-12%**	**-12%**	**-12%**	**-19%**
Locomotives (2285)	AL	0%	0%	0%	0%	0%	0%
	FL	0%	0%	0%	0%	0%	0%
	GA	+3%	+3%	+3%	+3%	+3%	+3%
	KY	0%	0%	0%	0%	0%	0%
	MS	0%	0%	0%	0%	0%	0%
	NC	0%	0%	0%	0%	0%	0%
	SC	0%	0%	0%	0%	0%	0%
	TN	-42%	-43%	-43%	-43%	-46%	-42%
	VA	-38%	-39%	+9%	+9%	+6%	-38%
	WV	+19%	+19%	+19%	+19%	+19%	+19%
	Total	**-11%**	**-11%**	**-5%**	**-5%**	**-6%**	**-11%**
Grand Total		**-8%**	**-7%**	**-77%**	**-71%**	**-7%**	**-7%**

Table 1.3-16 Base F Comparison of Aircraft Emissions (Airports with Aircraft NO_x > 200 tons per year)

Airport	FIP	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC	Approx. LTOs	Predicted NO_x	VISTAS to Predicted
Initial 2002 Base Year Inventory										
Miami	12086	9,757	5,997	23,706	16,357	525	1,641	150,000	1,680	3.57
Orlando	12095	3,456	2,170	8,578	5,919	204	642	150,000	1,680	1.29
Memphis	47157	3,462	1,934	7,645	5,275	185	603	125,000	1,400	1.38
Reagan	51013	3,892	1,806	7,138	4,925	164	302	100,000	1,120	1.61
Hampton	51650	2,690	1,705	0	0	0	611	Military		
Dulles	51059	2,032	1,330	5,246	3,620	0	272	75,000	840	1.58
Orlando-Sanford	12117	3,615	1,225	4,837	3,337	100	351			
Atlanta	13121	1,457	913	3,608	2,490	86	274	420,000	4,704	0.19
Fort Lauderdale	12011	1,930	809	3,196	2,206	75	257	75,000	840	0.96
Charlotte	37119	1,643	788	3,113	2,148	75	255	150,000	1,680	0.47
Tampa	12057	1,399	785	3,101	2,140	74	240	75,000	840	0.93
Nashville	47037	1,819	653	40	28	33	239	60,000	672	0.97
Raleigh	37183	1,584	592	2,338	1,613	56	204	75,000	840	0.70
Louisville	21111	1,073	468	1,851	1,277	45	155	60,000	672	0.70
Jacksonville	12031	871	325	1,284	886	31	112	30,000	336	0.97
Palm Beach	12099	1,156	226	0	0	1	132	30,000	336	0.67
Aggregate		41,836	21,724	75,682	52,220	1,655	6,290			0.19-3.57
Base F 2002 Base Year Inventory										
Atlanta	13063	4,121	5,288	1,435	1,406	443	337	420,000	4,704	1.12
Miami	12086	6,670	2,933	805	789	274	1,596	150,000	1,680	1.75
Orlando	12095	3,456	2,170	568	556	204	642	150,000	1,680	1.29
Memphis	47157	3,462	1,934	506	495	185	603	125,000	1,400	1.38
Orlando-Sanford	12117	3,615	1,225	338	332	100	351			
Fort Lauderdale	12011	1,930	809	217	212	75	257	75,000	840	0.96
Charlotte	37119	1,643	788	206	202	75	255	150,000	1,680	0.47
Tampa	12057	1,399	785	206	202	74	240	75,000	840	0.93
Nashville	47037	1,819	653	170	166	33	239	60,000	672	0.97
Reagan	51013	1,269	635	171	168	193	97	100,000	1,120	0.57
Dulles 1	51107	1,807	595	164	161	252	153	37,500	420	1.42
Raleigh	37183	1,584	592	156	153	56	204	75,000	840	0.70
Dulles 2	51059	1,095	591	156	153	252	115	37,500	420	1.41
Hampton	51650	858	535	471	461	18	305	Military		
Louisville	21111	1,073	468	123	121	45	155	60,000	672	0.70
Jacksonville	12031	871	325	87	85	31	112	30,000	336	0.97
Palm Beach	12099	1,156	226	59	58	1	132	30,000	336	0.67
Aggregate		37,829	20,550	5,838	5,721	2,312	5,793			0.47-1.75
Net Change		**-10%**	**-5%**	**-92%**	**-89%**	**+40%**	**-8%**			

Note: For the Base F inventory, Dulles International Airport emissions are split between two Virginia counties.
Predicted NO_x is based on the ratio of airport LTOs to test airport (Tucson International Airport) LTOs and NO_x.
This is not a rigorous comparison, but rather an approximate indicator of expected magnitude.

Base G Revisions:

Further revisions to the 2002 base year emissions inventory were implemented in response to additional state data submittals in the spring of 2006. The inventories developed through the Base F revision process (as described above) served as the starting point for the 2006 revisions. Thus, unless otherwise indicated below, all documented Base F revisions continue to apply to the Base G-revised 2002 base year inventory.

As part of the Base G review and update process, Virginia regulators provided 443 updated emission records for aircraft. These records reflected revisions to aircraft VOC, CO, and NO_x, and in a few cases SO_2, emissions records that were already in the Base F VISTAS 2002 inventory (as opposed to the addition of previously unreported data). The specific revisions broke down as follows:

Table 1.3-17 Base G VA Aircraft Records Updates

Aircraft Type	VOC	CO	NO_x	SO_2	Total
Military Aircraft	9	9	9	1	28
Commercial Aircraft	12	12	12	17	53
General Aviation Aircraft	65	66	66	0	197
Air Taxi Aircraft	56	56	53	0	165
Aggregate	142	143	140	18	443

Emissions values for each of the 443 records in the Base F 2002 VISTAS inventory were updated for Base G to reflect the revised data. However, as described above for the Base F revisions, all aircraft SO_2, PM_{10}, and $PM_{2.5}$ emissions in Virginia are estimated on the basis of CO (in the case of SO_2) and NO_x emissions (in the cases of PM_{10} and $PM_{2.5}$). Therefore, since Virginia regulators did not provide updated SO_2 emissions for all updated CO emissions records, or updated PM_{10} or $PM_{2.5}$ emissions for all updated NO_x emissions records, it was necessary to re-estimate aircraft SO_2, PM_{10}, and $PM_{2.5}$ emissions in all cases where updated CO or NO_x emissions were provided for Base G (and explicit SO_2 and/or PM_{10} and $PM_{2.5}$ emissions were not).

The procedure used to estimate the SO_2, PM_{10}, and $PM_{2.5}$ emissions revisions was identical to that described above for the Base F inventory revisions, except that revised SO_2-to-CO emissions ratios were calculated for commercial aircraft, where 12 pairs of revised CO and SO_2 emissions estimates were available. Although a single pair of revised CO and SO_2 emissions records was available for military aircraft, this was deemed an insufficient sample with which to replace the military aircraft SO_2-to-CO emissions ratios previously calculated in Base F. However, it is worth noting that the SO_2-to-CO emissions ratio for the revised military aircraft emissions pair

was within 16 percent of the previously calculated ratio, so any error associated with retention of the Base F ratio will be minor. Table 1.3-18 presents the emissions ratios.

Table 1.3-18 Calculated Base G Emission Ratios for VA.

Source	SCC	SO_2/CO (fall 2004)	SO_2/CO (spring 2006)	SO_2/CO (used in 2006)	PM_{10}/NO_x	$PM_{2.5}/PM_{10}$
Military Aircraft	2275001000	0.0215	0.0180	0.0215	0.88	0.98
Commercial Aircraft	2275020000	0.3292	0.0696	0.0696	0.26	0.98
General Aviation Aircraft	2275050000	0.00016	n/a	0.00016	1.9	0.98
Air Taxi Aircraft	2275060000	0.0015	n/a	0.0015	0.5	0.98

Application of the SO_2-to-CO emissions ratios to the 130 revised aircraft CO records, for which no corresponding SO_2 emission revisions were provided, resulted in an additional 130 aircraft SO_2 emission records updates for Virginia. Similarly, application of the PM_{10}-to-NO_x emissions ratios to the 140 revised aircraft NO_x records for which no corresponding PM_{10} emission revisions were provided, resulted in an additional 140 aircraft PM_{10} emission records updates for Virginia. Application of the $PM_{2.5}$-to-PM_{10} emissions ratios to the 140 revised aircraft PM_{10} records resulted in an additional 140 aircraft $PM_{2.5}$ emission records updates for Virginia. Thus, in total, 853 (443+130+140+140) Virginia aircraft emissions records were updated for Base G.

Also as part of the Base G review and update process, Alabama regulators provided 178 updated PM emission records for aircraft (89 records for PM_{10} and 89 records for $PM_{2.5}$), 42 additional emissions records for locomotives (14 records for VOC, 14 records for CO, and 14 records for NO_x), and 179 additional emission records for aircraft (30 records for VOC, 30 records for CO, 30 records for NO_x, 29 records for SO_2, 30 records for PM_{10}, and 30 records for $PM_{2.5}$). After review, it was determined that the 178 updated PM emission records for aircraft actually reflected the original (overestimated) aircraft PM data that was replaced universally throughout the VISTAS region for Base F. Implementing these latest revisions would, in effect, “undo” the Base F aircraft PM revisions. Following discussions with Alabama regulators, it was determined that the 178 aircraft PM records would not be updated for the Base G revisions.

The 42 additional emissions records for locomotives were determined to correspond exactly to existing SO_2, PM_{10}, and $PM_{2.5}$ emissions records already in the Base F VISTAS 2002 inventory. It is not clear why these existing records contained no corresponding data for VOC, CO, and NO_x, but those data are now reflected through the additional 42 records that have now been added to the Base G 2002 VISTAS inventory for Alabama.

After examining the 179 additional aircraft emissions records in conjunction with Alabama regulators, it was determined that 17 of the records (commercial aircraft records in Dale,

Limestone, and Talladega counties) were erroneous and should be excluded from the update. The remaining 162 records reflected additional general aviation, air taxi, and military aircraft activity in 20 counties and were specifically comprised of 27 records each for VOC, CO, NO_x, SO_2, PM_{10}, and $PM_{2.5}$. There were no further issues with the VOC, CO, NO_x, and SO_2 records and these were added to the Base G 2002 VISTAS inventory without change. It was, however, apparent that the PM_{10} and $PM_{2.5}$ records reflected an overestimation of aircraft PM similar to that which was previously corrected throughout the VISTAS region for Base F (as documented above). To overcome this overestimation, the additional aircraft PM_{10} and $PM_{2.5}$ records provided by Alabama regulators were replaced with revised emission estimates developed on the basis of the PM_{10}-to-NO_x and $PM_{2.5}$-to-PM_{10} ratios documented under the Base F revisions above. So although 27 aircraft PM_{10} records and 27 aircraft $PM_{2.5}$ records were added to the 2002 Alabama inventory, they reflected different emissions values than those provided directly by Alabama regulators.

In total, 204 additional emissions records (42 for locomotives and 162 for aircraft) were added to the Base G 2002 Alabama inventory.

Finally, as part of the Base G review and update process, Kentucky regulators provided 12 updated aircraft emission records for Boone County, to correct previously underestimated aircraft emissions associated with the Cincinnati/Northern Kentucky International Airport. VOC, CO, and NO_x emissions data were provided for military, commercial, general aviation, and air taxi aircraft. No associated updates for SO_2, PM_{10}, or $PM_{2.5}$ emissions were provided. Corresponding PM_{10} emission estimates were developed by applying the PM_{10}-to-NO_x ratios presented in Table 1.3-17 above to the updated NO_x emission estimates. $PM_{2.5}$ emission estimates were developed by applying the $PM_{2.5}$-to-PM_{10} ratios from that same table to the estimated PM_{10} emissions. SO_2 emission estimates were developed by applying the SO_2-to-PM_{10} ratios developed from the older data (i.e., the data being replaced) for Boone County aircraft to the updated PM_{10} emissions. Thus, a total of 24 inventory records for Kentucky were updated (VOC, CO, NO_x, SO_2, PM_{10}, and $PM_{2.5}$ for four aircraft types).

Upon implementation of the universe of updates, 877 existing emission records were revised (853 in Virginia and 24 in Kentucky) and 204 additional emission records (all in Alabama) were added to the 2002 VISTAS inventory. The total number of aircraft, locomotive, and commercial marine inventory records thus changed from 22,838 records in Base F to 23,042 records in Base G.

Table 1.3-19 presents a summary of the resulting Base G VISTAS 2002 base year inventory estimates for aircraft, locomotives, and non-recreational marine vessels. Table 1.3-20 provides a comparison of the Base G 2002 base year inventory estimates to those of the Base F 2002 base

year inventory. As indicated, total emissions for VOC, CO, NO_x, and SO_2 are generally within about 5 percent, with changes restricted to the states of Alabama, Kentucky, and Virginia.

Lastly, Table 1.3-21 provides an updated comparison of emission estimates from the Base F and Base G 2002 base year inventories for all 17 VISTAS region airports with estimated annual aircraft NO_x emissions of 200 tons or greater. As compared to Table 1.3-16, the table reflects the Base G addition of the Cincinnati/Northern Kentucky International Airport. Aircraft emission estimates for the other 16 airports are unchanged from their Base F values.

Table 1.3-19 Base G-Revised 2002 Base Year Aircraft, Locomotive, and Non-Recreational Marine Emissions (tons/year)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	5,595	185	238	99	18	276
	FL	25,431	8,891	2,424	2,375	800	3,658
	GA	6,620	5,372	1,475	1,446	451	443
	KY	5,577	925	251	246	88	397
	MS	1,593	140	44	43	13	96
	NC	6,088	1,548	419	411	148	613
	SC	6,505	515	409	401	88	863
	TN	7,251	2,766	734	719	235	943
	VA	11,873	3,885	2,010	1,970	272	2,825
	WV	1,178	78	25	24	8	66
	Total	**77,712**	**24,305**	**8,029**	**7,734**	**2,121**	**10,179**
Commercial Marine (2280)	AL	1,196	9,218	917	844	3,337	737
	FL	5,888	44,817	1,936	1,781	6,683	1,409
	GA	1,038	7,875	334	307	1,173	246
	KY	6,607	50,267	2,246	2,066	9,608	1,569
	MS	5,688	43,233	1,903	1,751	7,719	1,351
	NC	599	4,547	193	178	690	142
	SC	1,067	8,100	343	316	1,205	253
	TN	3,624	27,555	1,217	1,120	4,974	860
	VA	972	2,775	334	307	359	483
	WV	1,528	11,586	487	448	525	362
	Total	**28,207**	**209,972**	**9,911**	**9,118**	**36,275**	**7,413**
Military Marine (2283)	VA	110	313	25	23	27	48
	Total	**110**	**313**	**25**	**23**	**27**	**48**
Locomotives (2285)	AL	3,518	26,623	592	533	1,446	1,365
	FL	1,006	9,969	247	222	605	404
	GA	2,654	26,733	664	598	1,622	1,059
	KY	2,166	21,811	542	488	1,321	867
	MS	2,302	23,267	578	520	1,429	899
	NC	1,638	16,502	410	369	1,001	654
	SC	1,160	11,690	291	261	710	462
	TN	2,626	25,627	633	570	1,439	1,041
	VA	1,186	11,882	1,529	1,375	3,641	492
	WV	1,311	13,224	329	296	808	517
	Total	**19,568**	**187,328**	**5,815**	**5,232**	**14,022**	**7,761**
Grand Total		**125,597**	**421,918**	**23,780**	**22,107**	**52,444**	**25,401**

Table 1.3-20 Change in 2002 Emissions, Base G Inventory Relative to Base F Inventory

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	+48%	+6%	+5%	+14%	+7%	+41%
	FL	0%	0%	0%	0%	0%	0%
	GA	0%	0%	0%	0%	0%	0%
	KY	+109%	+41%	+40%	+40%	+41%	+51%
	MS	0%	0%	0%	0%	0%	0%
	NC	0%	0%	0%	0%	0%	0%
	SC	0%	0%	0%	0%	0%	0%
	TN	0%	0%	0%	0%	0%	0%
	VA	+22%	+41%	+77%	+77%	-65%	+12%
	WV	0%	0%	0%	0%	0%	0%
	Total	**+10%**	**+6%**	**+14%**	**+14%**	**-19%**	**+5%**
Commercial Marine (2280)	AL	0%	0%	0%	0%	0%	0%
	FL	0%	0%	0%	0%	0%	0%
	GA	0%	0%	0%	0%	0%	0%
	KY	0%	0%	0%	0%	0%	0%
	MS	0%	0%	0%	0%	0%	0%
	NC	0%	0%	0%	0%	0%	0%
	SC	0%	0%	0%	0%	0%	0%
	TN	0%	0%	0%	0%	0%	0%
	VA	0%	0%	0%	0%	0%	0%
	WV	0%	0%	0%	0%	0%	0%
	Total	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Military Marine (2283)	VA	0%	0%	0%	0%	0%	0%
	Total	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Locomotives (2285)	AL	+1%	+1%	0%	0%	0%	+1%
	FL	0%	0%	0%	0%	0%	0%
	GA	0%	0%	0%	0%	0%	0%
	KY	0%	0%	0%	0%	0%	0%
	MS	0%	0%	0%	0%	0%	0%
	NC	0%	0%	0%	0%	0%	0%
	SC	0%	0%	0%	0%	0%	0%
	TN	0%	0%	0%	0%	0%	0%
	VA	0%	0%	0%	0%	0%	0%
	WV	0%	0%	0%	0%	0%	0%
	Total	**+0%**	**+0%**	**0%**	**0%**	**0%**	**+0%**
Grand Total		**+6%**	**+0%**	**+4%**	**+4%**	**-1%**	**+2%**

Table 1.3-21 Base G Comparison of Aircraft Emissions (Airports with Aircraft NO_x > 200 tons per year)

Airport	FIP	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC	Approx. LTOs	Predicted NO_x	VISTAS to Predicted
Base F 2002 Base Year Inventory										
Atlanta	13063	4,121	5,288	1,435	1,406	443	337	420,000	4,704	1.12
Miami	12086	6,670	2,933	805	789	274	1,596	150,000	1,680	1.75
Orlando	12095	3,456	2,170	568	556	204	642	150,000	1,680	1.29
Memphis	47157	3,462	1,934	506	495	185	603	125,000	1,400	1.38
Orlando-Sanford	12117	3,615	1,225	338	332	100	351			
Fort Lauderdale	12011	1,930	809	217	212	75	257	75,000	840	0.96
Charlotte	37119	1,643	788	206	202	75	255	150,000	1,680	0.47
Tampa	12057	1,399	785	206	202	74	240	75,000	840	0.93
Nashville	47037	1,819	653	170	166	33	239	60,000	672	0.97
Reagan	51013	1,269	635	171	168	193	97	100,000	1,120	0.57
Dulles 1	51107	1,807	595	164	161	252	153	37,500	420	1.42
Raleigh	37183	1,584	592	156	153	56	204	75,000	840	0.70
Dulles 2	51059	1,095	591	156	153	252	115	37,500	420	1.41
Hampton	51650	858	535	471	461	18	305	Military		
Louisville	21111	1,073	468	123	121	45	155	60,000	672	0.70
Jacksonville	12031	871	325	87	85	31	112	30,000	336	0.97
Palm Beach	12099	1,156	226	59	58	1	132	30,000	336	0.67
Cincinnati	21015	467	144	38	37	14	54	50,000	560	0.26
Aggregate		38,296	20,694	5,876	5,758	2,326	5,847			0.26-1.75
Base G 2002 Base Year Inventory										
Atlanta	13063	4,121	5,288	1,435	1,406	443	337	420,000	4,704	1.12
Miami	12086	6,670	2,933	805	789	274	1,596	150,000	1,680	1.75
Orlando	12095	3,456	2,170	568	556	204	642	150,000	1,680	1.29
Memphis	47157	3,462	1,934	506	495	185	603	125,000	1,400	1.38
Orlando-Sanford	12117	3,615	1,225	338	332	100	351			
Fort Lauderdale	12011	1,930	809	217	212	75	257	75,000	840	0.96
Charlotte	37119	1,643	788	206	202	75	255	150,000	1,680	0.47
Tampa	12057	1,399	785	206	202	74	240	75,000	840	0.93
Nashville	47037	1,819	653	170	166	33	239	60,000	672	0.97
Reagan	51013	1,269	635	171	168	193	97	100,000	1,120	0.57
Dulles 1	51107	1,807	595	164	161	252	153	37,500	420	1.42
Raleigh	37183	1,584	592	156	153	56	204	75,000	840	0.70
Dulles 2	51059	1,095	591	156	153	252	115	37,500	420	1.41
Hampton	51650	858	535	471	461	18	305	Military		
Louisville	21111	1,073	468	123	121	45	155	60,000	672	0.70
Cincinnati	21015	3,378	411	110	107	39	187	50,000	560	0.73
Jacksonville	12031	871	325	87	85	31	112	30,000	336	0.97
Palm Beach	12099	1,156	226	59	58	1	132	30,000	336	0.67
Aggregate		41,207	20,961	5,947	5,828	2,352	5,981			0.47-1.75
Net Change		**+8%**	**+1%**	**+1%**	**+1%**	**+1%**	**+2%**			

Note: For the revised inventory, Dulles International Airport emissions are split between two Virginia counties.
Predicted NO_x is based on the ratio of airport LTOs to test airport (Tucson International Airport) LTOs and NO_x.
This is not a rigorous comparison, but rather an approximate indicator of expected magnitude.

1.3.2.3 Emissions from NONROAD Model Sources in Illinois, Indiana, and Ohio

As part of the Base G update process, VISTAS requested that emissions estimates for 2002 be produced for the states of Illinois, Indiana, and Ohio. These estimates were to be produced at the same spatial (i.e., county level by SCC) and temporal resolution as estimates for the VISTAS region.

The requested estimates were produced by extracting a complete set of county-level input data applicable to each of the three states from the latest version of the EPA's NMIM (National Mobile Inventory Model) model. This included appropriate consideration of all non-default NMIM input files generated by the Midwest Regional Planning Organization (MRPO), as described below. These input data were then assembled into appropriate input files for the Final NONROAD2005 model and emission estimates were produced using the same procedure employed for the VISTAS region as part of the Base G updates.

A complete set of monthly input data was developed for each county in Illinois, Indiana, and Ohio by extracting data from the following NMIM database files (using the NMIM MySQL query browser):

> county, countrynrfile, countyyear, countyyearmonth, countyyearmonthhour, gasoline, diesel, and natural gas

The database files:

> countrynrfile, countyyear, countyyearmonth, and gasoline

were non-default database files provided to VISTAS by the MRPO, and are intended to reflect the latest planning data being used by MRPO modelers.

From these files, monthly data for gasoline vapor pressure, gasoline oxygen content, gasoline sulfur content, diesel sulfur content for land-based equipment, diesel sulfur content for marine-based equipment, natural gas sulfur content, minimum daily temperature, maximum daily temperature, and average daily temperature were developed. In addition, the altitude and Stage II refueling control status of each county, as well as the identity of the associated equipment population, activity, growth, allocation, and seasonal distribution files, was determined. These data were then assembled into Final NONROAD2005 input files on a seasonal basis, with monthly data being arithmetically averaged to produce seasonal equivalents as follows:

> Winter = Average of December, January, and February
> Spring = Average of March, April, and May
> Summer = Average of June, July, and August,
> Fall = Average of September, October, and November

Unlike the VISTAS Base G approach, this approach results in the use of the following non-default data files during the Final NONROAD2005 modeling process:

Table 1.3-22 Non-Default Files Used for MRPO Modeling

Data File	Illinois	Indiana	Ohio
Activity File	1700002.act	1800002.act	3900002.act
Growth File	17000.grw	18000.grw	39000.grw
Population File	17000.pop	18000.pop	39000.pop
Season File	17000.sea	18000.sea	39000.sea
Inboard Marine Allocation File	17000wib.alo	18000wib.alo	39000wib.alo
Outboard Marine Allocation File	17000wob.alo	18000wob.alo	39000wob.alo
Specific Fuel Consumption	MRPO-specific file provided by MRPO modelers (arbitrarily named “mrpoBSFC.emf” for this work)		

One compromise was made relative to the level of resolution that is available through the basic approach described above, that being the treatment of ambient temperature data. Because NMIM offers a unique temperature profile for every U.S. county -- developed by aggregating temperature data from included and surrounding weather stations on the basis of their distances from the county population centroid -- it is not possible to explicitly group counties with otherwise identical input streams. Ungrouped however, there would be 1,128 distinct input streams to be processed (102 Illinois counties plus 92 Indiana counties plus 88 Ohio counties at four seasons each), or over five times the number of files processed for the entire VISTAS region.

To surmount this problem and allow counties with similar temperature profiles to be grouped an approach was employed wherein counties were considered groupable if *all* temperature inputs[4] are within ± 2 ºF of the corresponding group average. This criterion is quite stringent in that it results in less tolerant grouping than that employed for VISTAS modeling, which uses temperature data from the nearest meteorological station as opposed to "unique" meteorological

[4] Non-road temperature inputs used for county grouping are: winter minimum, spring minimum, summer minimum, fall minimum, winter maximum, spring maximum, summer maximum, fall maximum, winter average, spring average, summer average, and fall average.

data for each county. Under this approach, the actual deviation for grouped counties is *much* less that ± 2º F for the overwhelming majority of the 12 grouped temperature inputs.

In addition to the required temperature consistency, all other input data for counties to be grouped had to be identical for all four seasons. Using this criterion, Illinois emissions were modeled using 12 county groups, Indiana emissions were modeled using 9 county groups, and Ohio emissions were modeled using 10 county groups. Thus, 31 iterations of NONROAD2002 were required per season, as compared to the 53 iterations per season required for the VISTAS region.

It should be noted that a potential quality assurance issue was noted in assembling the NONROAD2005 input data for a number of Indiana counties. Specifically, the gasoline vapor pressure for most Indiana counties reflects a value of 9.0 psi in *all* spring, summer, fall, and winter months. This is likely to indicate a problem with the accuracy of the NMIM databases for these counties, but these data were used as defined for this work.

1.3.3 Quality Assurance steps

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, and to ensure that a full and complete inventory was developed for VISTAS. Quality assurance was an important component to the inventory development process and MACTEC performed the following QA steps on the area source component of the 2002 base year revised:

1. All CERR and NIF format State supplied data submittals were run through EPA's Format and Content checking software.

2. SCC level emission summaries were prepared and evaluated to ensure that emissions were consistent and that there were no missing sources.

3. Tier comparisons (by pollutant) were developed between the revised 2002 base year inventory and the initial base year inventory.

4. Data product summaries were provided to both the VISTAS Emission Inventory Technical Advisor and to Mobile Source SIWG representatives for review and comment. Changes based on these comments were implemented in the files.

5. Version numbering was used for all inventory files developed. The version numbering process used a decimal system to track major and minor changes. For example, a major change would result in a version going from 1.0 to 2.0. A minor change would cause a version number to go from 1.0 to 1.1. Minor changes resulting from largely editorial changes would result in a change from 1.00 to 1.01.

2.0 Projection Inventory Development

2.1 Point Sources

We used different approaches for different sectors of the point source inventory:

- For the EGUs, VISTAS relied primarily on the Integrated Planning Model® (IPM®) to project future generation as well as to calculate the impact of future emission control programs. The IPM results were adjusted based on S/L agency knowledge of planned emission controls at specific EGUs.
- For non-EGUs, we used recently updated growth and control data consistent with the data used in EPA's CAIR analyses, and supplemented these data with available S/L agency knowledge of planned emission controls or other changes at specific non-EGUs and updated fuel use forecast data for the U.S. Department of Energy.

For both sectors, we generated 2009 and 2018 inventories for a combined on-the-books (OTB) and on-the-way (OTW) control scenario. The OTB/OTW control scenario accounts for post-2002 emission reductions from promulgated and proposed non-EGU federal control programs as of July 1, 2004; the final Clean Air Interstate Rule (CAIR); and State, local, and site-specific control programs as of October 1, 2007. Section 2.1.1 discusses the EGU projection inventory development, while Section 2.1.2 discusses the non-EGU projection inventory development.

2.1.1 EGU Emission Projections

The following subsections discuss the following specific aspects of the development of the EGU projections. First, we present a chronology of the EGU development process and discuss key decisions in selecting the final methods for performing the emissions projections. Next, we describe the development of the final set of IPM runs that are included in the VISTAS Base G inventory. Next, we describe the process of transforming the IPM parsed files into NIF format. Fourth, we discuss the process for ensuring that units accounted for in IPM were not double-counted in the non-EGU inventory. Fifth, we describe the QA/QC checks that were made to ensure that the IPM results were properly incorporated into the VISTAS inventory. Sixth, we document the changes to the IPM results that S/L agencies specified they wanted included in the VISTAS inventory based on new information that were not accounted for in the IPM runs. Finally, we present summaries of the B&F projected EGU emissions by year, state, and pollutant.

2.1.1.1 Chronology of the Development of EGU Projections

At the beginning of the EGU inventory development process, VISTAS considered three options for developing the VISTAS 2009 and 2018 projection inventories for EGUs:

- Option 1 – Use the results of IPM modeling conducted in support of the proposed Clean Air Interstate Rule (CAIR) base and control case analyses as the starting point and refine the projections with readily available inputs from stakeholders; these IPM runs were conducted for 2010 and 2015, which VISTAS would use to represent projected emissions in 2009 and 2018 respectively.
- Option 2 – Use the VISTAS 2002 typical year as the starting point, apply growth factors from the Energy Information Administration, and refine future emission rates with stakeholder input regarding utilization rates, capacity, retirements, and new unit information.
- Option 3 – Use the results of a new round of IPM modeling sponsored by VISTAS and the Midwest Regional Planning Organization (MRPO). These runs incorporated VISTAS specific unit and regulation modified parameters, and generate results for 2009 and 2018 explicitly.

An additional consideration for each of the three options was the inclusion of emission projections developed by the Southern Company specifically for their units. Southern Company is a super-regional company which owns EGUs in Alabama, Florida, Georgia, and Mississippi and participates in VISTAS as an industry stakeholder. Southern Company used their energy budget forecast to project net generation and heat input for every existing and future Southern Company EGU for the years 2009 and 2018. Further documentation of how Southern Company generated the 2009/2018 inventory for their units can be found in *Developing Southern Company Emissions and Flue Gas Characteristics for VISTAS Regional Haze Modeling (April 2005, presented at 14th International Emission Inventory Conference).*

Each of these three options and the Southern Company projections were discussed in a series of conference calls with the VISTAS EGU Special Interest Work Group (SIWG) during the fall of 2004. During a conference call on December 6, 2004, the VISTAS EGU SIWG approved the use of the latest VISTAS/MRPO sponsored IPM runs (Option 3) to represent the 2009 and 2018 EGU forecasts of emissions for the OTB and OTW cases. During the call, Alabama and Georgia specified that they did not wish to use Southern Company provided emissions forecasts of 2009 and 2018 to represent the sources in their States. Mississippi decided to utilize the Southern Company projections to represent activity at Southern Company facilities in Mississippi. After the call, Florida decided against using Southern Company provided emissions forecasts of 2009 and 2018 to represent the sources in their State. Thus, Southern Company data was used only for Southern Company units in Mississippi for both the Base F and Base G projections.

The Option 3 IPM modeling resulted from a joint agreement by VISTAS and MRPO to work together to develop future year utility emissions based on IPM modeling. The decision to use

IPM modeling was based in part on a study of utility forecast methods by E.H. Pechan and Associates, Inc. (Pechan) for MRPO, which recommended IPM as a viable methodology (see *Electricity Generating Unit {EGU} Growth Modeling Method Task 2 Evaluation*, February 11, 2004). Although IPM results were available from EPA's modeling to support their rulemaking for the Clean Air Interstate Rule (CAIR), VISTAS stakeholders felt that certain model inputs needed to be improved. Thus, VISTAS and MRPO decided to hire contractors to conduct new IPM modeling and to post-process the IPM results. Southern Company projections in 2009 were roughly comparable with IPM. For 2018, Southern Company projections were generally less than IPM because of assumptions made by Southern Company on which units would be economical to control and incorrect data in the NEEDS database which feeds IPM.

In August 2004, VISTAS contracted with ICF International, Inc., to run IPM to provide utility forecasts for 2009 and 2018 under two future scenarios – Base Case and CAIR Case. The Base Case represents the current operation of the power system under currently known laws and regulations (as known at the time the run was made), including those that come into force in the study horizon. The CAIR Case is the Base Case with the proposed CAIR rule superimposed. The run results were parsed at the unit level for the 2009 and 2018 run years. Also in August 2004, MRPO contracted with E.H. Pechan to post-process the IPM outputs generated by ICF to provide model-ready emission files. The IPM output files were delivered by ICF to VISTAS in November (*Future Year Electricity Generating Sector Emission Inventory Development Using the Integrated Planning Model (IPM®) in Support of Fine Particulate Mass and Visibility Modeling in the VISTAS and Midwest RPO Regions*, January 2005), and the post-processed data files were delivered by Pechan to the MRPO in December 2004 (*LADCO IPM Model Parsed File Post-Processing Methodology and File Preparation*, February 8, 2005).

On March 10, 2005, EPA issued the final Clean Air Interstate Rule. VISTAS and MRPO, in conjunction with other RPOs, conducted another round of IPM modeling which reflected changes to control assumptions based on the final CAIR as well as additional changes to model inputs based on S/L agency and stakeholder comments. Several conference calls were conducted in the spring of 2005 to discuss and provide comments on IPM assumptions related to six main topics: power system operation, generating resources, emission control technologies, set-up parameters and rule, financial assumptions, and fuel assumptions. Based on these discussions, VISTAS sponsored a new set of IPM runs to reflect the final CAIR requirements as well as certain changes to IPM assumptions that were agreed to by the VISTAS states. This set of IPM runs is documented in *Future Year Electricity Generating Sector Emission Inventory Development Using the Integrated Planning Model (IPM®) in Support of Fine Particulate Mass and Visibility Modeling in the VISTAS and Midwest RPO Regions*, April 2005 (these runs are referred to as the VISTAS Phase I analysis).

Further refinements to the IPM inputs and assumptions were made by the RPOs, and ICF performed the following four runs using IPM during the summer of 2005 (these runs are referred to as the VISTAS/CENRAP Phase II analysis):

- Base Case with EPA 2.1.9 coal, gas and oil price assumptions.
- Base Case with EPA 2.1.9 coal and gas supply curves adjusted for AEO 2005 reference case price and volume relationships.
- Strategy Case with EPA 2.1.9 coal, gas and oil price assumptions.
- Strategy Case with EPA 2.1.9 coal and gas supply curves adjusted for AEO 2005 reference case price and volume relationships.

The above runs were parsed for 2009 and 2018 run years. The above four runs were based on VISTAS Phase I and the EPA 2.1.9 assumptions. The changes that were implemented in the above four runs are summarized below:

- Unadjusted AEO 2005 electricity demand projections were incorporated in the above four runs.
- The gas supply curves were adjusted for AEO 2005 reference case price and volume relationships. The EPA 2.1.9 gas supply curves were scaled such that IPM will solve for AEO 2005 gas prices when the power sector gas demand in IPM is consistent with AEO 2005 power sector gas demand projections.
- The coal supply curves used in EPA 2.1.9 were scaled in such a manner that the average mine mouth coal prices that the IPM is solving in aggregated coal supply regions are comparable to AEO 2005. Due to the fact that the coal grades and supply regions between AEO 2005 and the EPA 2.1.9 are not directly comparable, this was an approximate approach and had to be performed in an iterative fashion. The coal transportation matrix was not updated with EIA assumptions due to significant differences between the EPA 2.1.9 and EIA AEO 2005 coal supply and coal demand region configurations.
- The cost and performance of new units were updated to AEO 2005 reference case levels in all of the above four funs.
- The run years 2008, 2009, 2012, 2015, 2018, 2020 and 2026 were modeled.
- The AEO 2005 life extension costs for fossil and nuclear units were incorporated in the above runs.

- The extensive NEEDS comments provided by VISTAS, MRPO, CENRAP and MANE-VU were incorporated into the VISTAS Phase I NEEDS.
- MANE-VU's comments in regards to the state regulations in the northeast were incorporated.
- Renewable Portfolio Standards (RPS) in the northeast was modeled based on the Regional Greenhouse Gas Initiative analysis. A single RPS cap was modeled for MA, RI, NY, NJ, MD and CT. These states could buy credits from NY, PJM and New England model regions.
- The investments required under the Illinois power, Mirant and First Energy NSR settlements were incorporated in the above runs.

For the VISTAS/CENRAP Phase II set of IPM runs, ICF generated two different parsed files. One file includes all fuel burning units (fossil, biomass, landfill gas) as well as non-fuel burning units (hydro, wind, etc.). The second file contains just the fossil-fuel burning units (e.g., emissions from biomass and landfill gas are omitted). The RPOs decided to use the fossil-only file for modeling to be consistent with EPA, since EPA used the fossil only results for CAIR analyses. For the 10 VISTAS states, non-fossil fuels accounted for only 0.13 percent of the NOx emissions and 0.04 percent of the SO_2 emissions in the 2009 IPM runs.

S/L agencies reviewed the results of the VISTAS/CENRAP Phase II set of IPM runs, which were incorporated into the VISTAS Base F inventory. S/L agencies primarily reviewed and commented on the IPM results with respect to IPM decisions on NO_x post-combustion controls and SO_2 scrubbers. S/L agencies provided the latest information on when and where new SO_2 and NO_x controls are planned to come online. S/L agencies also reviewed the IPM results to verify that existing controls and emission rates were properly reflected in the IPM runs. As directed by the S/L agencies, adjustments to the IPM results were made to specific units with any new information they had as part of the permitting process or other contact with the industry that indicates which units will install controls as a result of CAIR and when these new controls will come on-line. Mississippi decided to continue to use the Southern Company projections instead of the IPM projections to represent emissions at Southern Company facilities in Mississippi. The initial set of state-specified changes to the VISTAS/CENRAP Phase II set of IPM runs were used to create the Base G projection inventory (and are documented later in Section 2.1.1.6). The second set of state specified changes were made only for the 2018 inventory, resulting in the Base G2 2018 inventory (documented later in Section 2.1.1.7). The final set of state specified changes applied to both the 2009 and 2018 inventories and were used to create the B&F 2009 and 2018 inventories (documented later in Section 2.1.1.8).

2.1.1.2 VISTAS IPM runs for EGU sources

The following general summary of the VISTAS IPM® modeling is based on ICF's documentation *Future Year Electricity Generating Sector Emission Inventory Development Using the IPM® in Support of Fine Particulate Mass and Visibility Modeling in the VISTAS and Midwest RPO Regions*, April 2005. The ICF documentation is to be used as an extension to EPA's proposed CAIR modeling runs documented in *Documentation Supplement for EPA Modeling Applications (V.2.1.6) Using the IPM*, EPA 430/R-03-007, July 2003.

IPM provides "forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints." The underlying database in this modeling is U.S. EPA's National Electric Energy Data System (NEEDS) released with the CAIR Notice of Data Availability (NODA). The NEEDS database contains the existing and planned/committed unit data in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units. VISTAS States and stakeholders provided changes for:

- NO_x post-combustion control on existing units
- SO_2 scrubbers on existing units
- SO_2 emission limitations
- PM controls on existing units
- Summer net dependable capacity
- Heat rate for existing units
- SO_2 and NO_x control plans based on State rules or enforcement settlements

The years 2009 and 2018 were explicitly modeled.

2.1.1.3 Post-Processing of IPM Parsed Files

The following summary of the VISTAS/Midwest Regional Planning Organization (MRPO) IPM modeling is based on Pechan's documentation *LADCO IPM Model Parsed File Post-Processing Methodology and File Preparation*, February 8, 2005. The essence of the IPM model post-processing methodology is to take an initial IPM model output file and transform it into air quality model input files. ICF via VISTAS/MRPO provides an initial spreadsheet file containing unit-level records of both

(1) "existing" units and

(2) committed or new generic aggregates.

All records have unit and fuel type data; existing, retrofit (for SO_2 and NO_x), and separate NO_x control information; annual SO_2 and NO_x emissions and heat input; summer season (May-September) NO_x and heat input; July day NO_x and heat input; coal heat input by coal type;

nameplate capacity megawatt (MW), and State FIPS code. Existing units also have county FIPS code, a unique plant identifier (ORISPL) and unit ID (also called boiler ID) (BLRID); generic units do not have these data. The processing includes estimating various types of emissions and adding in control efficiencies, stack parameters, latitude-longitude coordinates, and State identifiers (plant ID, point ID, stack ID, process ID). Additionally, the generic units are sited in a county and given appropriate IDs. This processing is described in more detail below.

The data are prepared by transforming the generic aggregates into units similar to the existing units in terms of the available data. The generic aggregates are split into smaller generic units based on their unit types and capacity, are provided a dummy ORIS unique plant and boiler ID, and are given a county FIPS code based on an algorithm that sites each generic by assigning a sister plant that is in a county based on its attainment/nonattainment status. Within a State, plants (in county then ORIS plant code order) in attainment counties are used first as sister sites to generic units, followed by plants in PM nonattainment counties, followed by plants in 8-hour ozone nonattainment counties. Note that no LADCO or VISTAS States provided blackout counties that would not be considered when siting generics, so this process is identical to the one used for EPA IPM post-processing.

SCCs were assigned for all units; unit/fuel/firing/bottom type data were used for existing units' assignments, while only unit and fuel type were used for generic units' assignments. Latitude-longitude coordinates were assigned, first using the EPA-provided data files, secondly using the September 17, 2004 Pechan in-house latitude-longitude file, and lastly using county centroids. These data were only used when the data were not provided in the 2002 NIF files. Stack parameters were attached, first using the EPA-provided data files, secondly using a March 9, 2004 Pechan in-house stack parameter file based on previous EIA-767 data, and lastly using an EPA June 2003 SCC-based default stack parameter file. These data were only used when the data were not provided in the 2002 NIF files.

Additional data were required for estimating VOC, CO, filterable primary PM_{10} and PM2.5, PM condensable, and NH_3 emissions for all units. Thus, ash and sulfur contents were assigned by first using 2002 EIA-767 values for existing units or SCC-based defaults; filterable PM10 and PM2.5 efficiencies were obtained from the 2002 EGU NEI that were based on 2002 EIA-767 control data and the PM Calculator program (a default of 99.2 percent is used for coal units if necessary); fuel use was back calculated from the given heat input and a default SCC-based heat content; and emission factors were obtained from an EPA-approved October 7, 2004 Pechan emission factor file based on AP-42 emission factors. Note that this updated file is not the one used for estimating emissions for previous EPA post-processed IPM files. Emissions for 28 temporal-pollutant combinations were estimated since there are seven pollutants (VOC, CO, primary PM_{10} and $PM_{2.5}$, NH_3, SO_2 and NO_x) and four temporal periods (annual, summer season, winter season, July day).

The next step was to match the IPM unit IDs with the identifiers in VISTAS 2002 inventory. A crosswalk file was used to obtain FIPS State and county, plant ID (within State and county), and point ID. If the FIPS State and county, plant ID and point ID are in the 2002 VISTAS NIF tables, then the process ID and stack ID are obtained from the NIF; otherwise, defaults, described above, were used.

Pechan provided the post-processed files in NIF 3.0 format. Two sets of tables were developed : "NIF files" for IPM units that have a crosswalk match and are in the 2002 VISTAS inventory, and "NoNIF files" for IPM units that are not in the 2002 VISTAS inventory (which includes existing units with or without a crosswalk match as well as generic units).

For Base F and Base G projections, VISTAS reviewed the PM and NH_3 emissions from EGUs as provided by Pechan and identified significantly higher emissions in 2009/2018 than in 2002. VISTAS determined that Pechan used a set of PM and NH_3 emission factors that are "the most recent EPA approved uncontrolled emission factors" for estimating 2009/2018 emissions. These factors are most likely not the same emission factors used by States for estimating these emissions in 2002 for EGUs in the VISTAS domain. Thus, the emission increase from 2002 to 2009/2018 was simply an artifact of the change in emission factor, not anything to do with changes in activity or control technology application. Also, VISTAS identified an inconsistent use of SCCs for determining emission factors between the base and future years.

VISTAS resolution of the PM and NH_3 problem is fully documented in *EGU Emission Factors and Emission Factor Assignment*, memorandum from Greg Stella to VISTAS State Point Source Contacts and VISTAS EGU Special Interest Workgroup, June 13, 2005. The first step was the adjustment of the 2002 base year emissions inventory. Using the latest "EPA-approved" uncontrolled emission factors by SCC, Alpine Geophysics utilized CERR or VISTAS reported annual heat input, fuel throughput, heat, ash and sulfur content to estimate annual uncontrolled emissions for units identified as output by IPM. This step was conducted for non-CEM pollutants (CO, VOC, PM, and NH_3) only. For PM emissions, the condensable component of emissions was calculated and added to the resulting PM primary estimations. The resulting emissions were then adjusted by any control efficiency factors reported in the CERR or VISTAS data collection effort. The second adjustment was to the future year inventories. Alpine Geophysics updated the SCCs in the future year inventory to assign the same base year SCC. Using the same methods as described for the 2002 revisions, those non-IPM generated pollutants were estimated using IPM predicted fuel characteristics and base year 2002 SCC assignments.

2.1.1.4 Eliminating Double Counting of EGU Units

The following procedures were used to avoid double counting of EGU emissions in the 2009/2018 point source inventory. The 2002 VISTAS point source emission inventory contains both EGUs and non-EGUs. Since this file contains both EGUs and non-EGU point sources, and

EGU emissions are projected using the IPM, it was necessary to split the 2002 point source file into two components. The first component contains those emission units accounted for in the IPM forecasts. The second component contains all other point sources not accounted for in IPM.

As described in the previous section, Pechan developed 2009/2018 NIF files for EGUs from the IPM parsed files. All IPM matched units were initially removed from the 2009/2018 point source inventory to create the non-EGU inventory (which was projected to 2009/2018 using the non-EGU growth and control factors described in Section 2.1.2). This was done on a unit-by-unit basis based on a cross-reference table that matches IPM emission unit identifiers (ORISPL plant code and BLRID emission unit code) to VISTAS NIF emission unit identifiers (FIPSST state code, FIPSCNTY county code, State Plant ID, State Point ID). When there was a match between the IPM ORISPL/BLRID and the VISTAS emission unit ID, the unit was assigned to the EGU inventory; all other emission units were assigned to the non-EGU inventory.

If an emission unit was contained in the NIF files created by Pechan from the IPM output, the corresponding unit was removed from the initial 2009/2018 point source inventory. The NIF 2009/2018 EGU files from the IPM parsed files were then merged with the non-EGU 2009/2018 files to create the 2009/2018 Base F point source files.

Next, we prepared several ad-hoc QA/QC queries to verify that there was no double-counting of emissions in the EGU and non-EGU inventories:

- We reviewed the IPM parsed files {VISTASII_PC_1f_AllUnits_2009 (To Client).xls and VISTASII_PC_1f_AllUnits_2018 (To Client).xls} to identify EGUs accounted for in IPM. We compared this list of emission units to the non-EGU inventory derived from the VISTAS cross-reference table to verify that units accounted for in IPM were not double-counted in the non-EGU inventory. As a result of this comparison, we made a few adjustments in the cross-reference table to add emission units for four plants to ensure these units accounted for in IPM were moved to the EGU inventory.

- We reviewed the non-EGU inventory to identify remaining emission units with an Standard Industrial Classification (SIC) code of “4911 Electrical Services” or Source Classification Code of “1-01-xxx-xx External Combustion Boiler, Electric Generation”. We compared the list of sources meeting these selection criteria to the IPM parsed file to ensure that these units were not double-counted.

S/L agencies also reviewed the 2009/2018 point source inventory to verify whether there was any double counting of EGU emissions. In two instances, S/L agencies provided corrections where an emission unit was double counted.

2.1.1.5 Quality Assurance Steps

Quality assurance was an important component to the inventory development process. The following QA steps on the EGU component of the VISTAS revised 2009/2018 EGU inventory:

1. Provided parsed files (i.e., Excel spreadsheets that provide unit-level results derived from the model plant projections obtained by the IPM) to the VISTAS EGU SIWG for review.
2. Provided facility level emission summaries for 2009/2018 for both the base case and CAIR case to the VISTAS EGU SIWG to ensure that emissions were consistent and that there were no missing sources.
3. Compared, at the State-level, emissions from the IPM parsed files and the post-processed NIF files to verify that the post-processed NIF files were consistent with the IPM parsed file results.

VISTAS requested S/L review of these files – the changes specified by states as a result of this review are documented in the following subsection.

2.1.1.6 S/L Adjustments to IPM Modeling Results for Base G Projections

After S/L agency review of the final set of IPM runs (as incorporated into the Base F inventory), S/L agencies specified a number of changes to the IPM results to better reflect current information on when and where future controls would occur. These changes to the IPM results primarily involved S/L agency addition or subtraction future emission controls based on the best available data from state rules, enforcement agreements, compliance plans, permits, and discussions/commitments from individual companies.

For example, Dominion Virginia Power released their company-wide plan to reduce emission to meet the requirements of CAIR and other programs. This plan varies substantially from the IPM results both in terms current and future controls and timing of these controls. As a result, VA DEQ developed their best estimates of future controls on EGUs in Virginia. Also, Duke Energy and Progress Energy have updated their plans for complying with North Carolina's Clean Smokestack Act. These plans vary substantially from the IPM results both in terms current and future controls and timing of these controls. As a result, NC DENR replaced the IPM emission projections for 2009 with projections from the Duke Energy and Progress Energy compliance plan. NC DENR elected to use the IPM results for 2018.

Some S/L agencies specified changes to the controls assigned by IPM to reflect their best estimates of emission controls. These changes involved either 1) adding selective catalytic reduction (SCR) or scrubber controls to units where IPM did not predict SCR or scrubber controls, or 2) removing IPM-assigned SCR or scrubber controls at units where the S/L agency indicated their were no firm plans for controls at those units. We generally used a control

efficiency of 90 percent when adding or removing SO_2 scrubber controls (unless a different control efficiency was provided by the State). We generally used a control efficiency of 90 percent when adding or removing NO_x SCR controls at coal-fired plants, 80 percent when adding or removing NO_x SCR controls at gas-fired plants, and 35 percent when adding or removing NO_x SNCR controls (unless a different control efficiency was provided by the State). The changes specified by the S/L agencies are summarized in Table 2.1-1. A comparison of the IPM and VISTAS control assumptions for all coal-fired EGUs in the Base G/G2 inventories are summarized in Appendix H. In addition to the changes to the IPM-assigned controls, the S/L agencies also specified other types of changes to the IPM results. These other specific changes to the IPM results are summarized in Table 2.1-2.

S/L agencies provided information and/or comment on changes in stack parameters from the 2002 inventory for 2009/2018 inventory. Changes to stack parameters were also made in cases where new controls are scheduled to be installed. In cases where an emission unit projected to have a SO_2 scrubber in either 2009 or 2018, some states were able to provide revised stack parameters for some units based on design features for the new control system. Other units projected to install scrubbers by 2009 or 2018 are not far enough along in the design process to have specific design details. For those units, the VISTAS EGU SIWG made the following assumptions: 1) the scrubber is a wet scrubber; 2) keep the current stack height the same; 3) keep the current flow rate the same, and 4) change the stack exit temperature to 169 degrees F (this is the virtual temperature derived from a wet temperature of 130 degrees F). VISTAS determined that exit temperature (wet) of 130 degrees F +/- 5 degrees F is representative of different size units and wet scrubber technology.

2.1.1.7 S/L Adjustments to IPM Modeling Results for Base G2 2018 Projections

Following release of the Base G inventory, four States specified additional changes to reflect their best estimates of emission controls in 2018. These additional changes are marked with an "*" in Tables 2.1-1 and 2.1-2. The following changes were requested and implemented in the VISTAS 2018 Base G2 EGU emissions and modeling inventories:

- **Florida** - Removed scrubbers from Smith units 1 & 2. Added scrubbers to Crist units 4, 5, & 6. Forecast emissions (from 2002 base) using growth factors for Northside units 1A and 2A. These units were estimated to be non operational in the IPM base case run.
- **Georgia** - Added scrubbers to Plant Scherer (Units 1-4) and Plant Yates (Units 6 & 7).
- **North Carolina** - Remove scrubber from F Lee unit 3.
- **West Virginia** - Pleasants Units 1 and 2 had SO2 emissions reduced to account for the facility's inclusion of previously bypassed 15% effluent stream to the scrubber and the control efficiency and emissions will reflect a change from 79.9% to 95% control.

Table 2.1-1 Adjustments to IPM Control Determinations Specified by S/L Agencies for the Base G/G2 2009/2018 EGU Inventories.

State	Plant Name and ID	Unit	NO_x Retrofit Emission Controls				SO_2 Retrofit Emission Controls			
			2009		2018		2009		2018	
			IPM	State	IPM	State	IPM	State	IPM	State
AL	James H. Miller ORISID=6002	1 & 2	SCR during ozone season	SCR probable year round due to CAIR	SCR during ozone season	SCR probable year round due to CAIR	None	None	None	Scrubber
		3 & 4	SCR during ozone season	SCR year round from Consent Decree	SCR during ozone season	SCR year round from Consent Decree	None	None	None	Scrubber
	Barry ORISID=3	1, 2, 3	None	SNCR	SCR	SNCR	None	None	None	None
		4	None	SNCR	SCR	SNCR	None	None	Scrubber	Scrubber
		5	None	None	SCR	SCR	None	None	Scrubber	Scrubber
	E C Gaston ORISID=26	1 - 4	SCR	None	SCR	None	None	None	Scrubber	Scrubber
		5	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber
	Gorgas ORISID=8	6 & 7	None	None	None	None	None	None	None	None
		8 & 9	None	None	None	None	None	Scrubber	None	Scrubber
		10	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	Charles R. Lowman ORISID=56	1	None	None	None	None	None	Scrubber	None	Scrubber
		2 & 3	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
FL	Lansing Smith ORISID=643	1	None	None	SCR	SCR	None	None	Scrubber	None*
		2	None	None	SCR	SCR	None	None	Scrubber	None*
	Northside ORISID=667	1A & 1B	No operation	No operation	No operation	No control, emissions forecasted using growth rates*	No operation	No operation	No operation	No control, emissions forecasted using growth rates*

Table 2.1-1 (continued)

State	Plant Name and ID	Unit	NO_x Retrofit Emission Controls				SO_2 Retrofit Emission Controls			
			2009		2018		2009		2018	
			IPM	State	IPM	State	IPM	State	IPM	State
FL	Crist	4	None	None	None	None	None	None	None	Scrubber*
	ORISID=641	5	None	None	None	None	None	None	None	Scrubber*
		6	None	None	None	None	None	None	None	Scrubber*
GA	Bowen	1BLR	SCR	SCR	SCR	SCR	IPM had retrofit scrubbers but little emission reductions	None	Scrubber	Scrubber
	ORISID=703	2BLR	SCR	SCR	SCR	SCR		None	Scrubber	Scrubber
		3BLR	SCR	SCR	SCR	SCR		Scrubber	Scrubber	Scrubber
		4BLR	SCR	SCR	SCR	SCR		Scrubber	Scrubber	Scrubber
	Wansley	1	SCR	SCR	SCR	SCR	IPM had retrofit scrubbers but little emission reductions	Scrubber	Scrubber	Scrubber
	ORISID=6052	2	SCR	SCR	SCR	SCR		None	Scrubber	Scrubber
	Kraft	1, 2	None	None	None	None	None	None	None	None
	ORISID=733	3	None	None	SCR	None	None	None	None	None
	McIntosh ORISID=6124	1	None	None	SCR	None	None	None	None	None
	Yates	1	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
	ORISID=728	2, 3	None	None	None	None	None	None	None	None
		4, 5	None	None	SCR	SCR	None	None	Scrubber	None
		6, 7	None	None	SCR	SCR	None	None	Scrubber	Scrubber*

Table 2.1-1 (continued)

State	Plant Name and ID	Unit	NO_x Retrofit Emission Controls				SO_2 Retrofit Emission Controls			
			2009		2018		2009		2018	
			IPM	State	IPM	State	IPM	State	IPM	State
GA	Hammond	1	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	ORISID=708	2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		3	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		4	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
	Scherer	1	None	None	None	None	None	None	None	Scrubber*
	ORISID=6257	2	None	None	None	None	None	None	None	Scrubber*
		3	None	None	None	None	None	None	None	Scrubber*
		4	None	None	None	None	None	None	None	Scrubber*
KY	Ghent	1	None	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
	ORISID=1356	2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		3, 4	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	Coleman	C1	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	ORISID=1381	C2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		C3	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	HMP&L Station 2	H1	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
		H2	None	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
	E W Brown	1	None	None	None	None	None	Scrubber	None	Scrubber
	ORISID=1355	2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		3	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
SC	Jeffries	3	SCR	None	SCR	None	None	None	None	None
	ORISID=3319	4	None	None	None	None	None	None	None	None
	Wateree	WAT1	SCR	SCR	SCR	SCR	None	Scrubber	None	Scrubber
	ORISID=3297	WAT2	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber

Table 2.1-1 (continued)

State	Plant Name and ID	Unit	NO_x Retrofit Emission Controls				SO_2 Retrofit Emission Controls			
			2009		2018		2009		2018	
			IPM	State	IPM	State	IPM	State	IPM	State
SC	Canadys	CAN1	None	None	None	None	None	None	None	None
	ORISID=3280	CAN2	None	None	None	None	None	None	None	None
		CAN3	None	None	None	None	None	Scrubber	None	Scrubber
	Rainey	CT1A	None	SCR	None	SCR	None	None	None	None
	ORISID=7834	CT1B	None	SCR	None	SCR	None	None	None	None
TN	Kingston	1 – 8	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
	ORISID=3407	9	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
	Johnsonville	1 – 10	SCR	None	SCR	SCR	None	None	None	None
	ORISID=3406									
WV	Willow Island	2	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
	ORISID=3946									
	Kammer	1 -3	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
	ORISID=3947									

Note: See Appendix H for a complete list of IPM and VISTAS control determinations for all coal and oil/gas units.

Table 2.1-2 Other Adjustments to IPM Results Specified by S/L Agencies for the Base G/G2 2009/2018 EGU Inventories.

State	Plant Name and ID	Unit	Nature of Update/Correction
FL	Central Power and Lime ORISID= 10333	GEN1	Central Power and Lime (ORIS10333) is a duplicate entry. This is point 18 in Florida Crushed Stone (12-053-0530021). Removed IPM emissions for Central Power and Lime.
	Cedar Bay Generating ORISID=10672	GEN1	FLDEP disagrees with IPM projections - no knowledge of expansion of this facility and the cogeneration facility should not grow faster than the underlying industry. Cedar Bay is connected to Stone Container (12-031-0310067). Replaced IPM emissions with 2002 emissions for Cedar Bay (12-031-0310337) times the growth factors for Stone Container.
	Indiantown Cogeneration ORISID=50976	GEN1	FLDEP disagrees with IPM projections - no knowledge of expansion of this facility and the cogeneration facility should not grow faster than the underlying industry. Indiantown is connected to Louis Dreyfus Citrus (12-085-0850002). Replaced IPM emissions with 2002 emissions for Indiantown (12-085-0850102) times the growth factors for Louis Drefus Citrus.
GA	Bowen ORISID=703	1BLR 2BLR 3BLR 4BLR	IPM indicated retrofit scrubbers on all 4 units in 2009, but the IPM emissions showed little reductions from 2002 levels. Changed emissions to reflect scrubbers on 3BLR and 4BLR by 2009.
	Wansley ORISID=6052	1, 2	IPM indicated retrofit scrubbers on both units in 2009, but the IPM emissions showed little reductions from 2002 levels. Changed emissions to reflect one scrubber on Unit 1 by 2009.
	Riverside ORISID=734	4	All of plant Riverside was retired from service June 1, 2005; emissions set to zero in 2009 and 2018.
	McIntosh ORISID=727	CT10A CT10B CT11A CT11B	The McIntosh Combined Cycle facility became commercial June 1, 2005. Added 346 tons of NO_x and 121 tons of SO_2 per unit to the 2009 and 2018 inventories.
	Longleaf Energy Station	1, 2	Longleaf Energy Station is being proposed by LS Power Development, Inc. GA specified that the emissions from this proposed plant be included in the 2018 projections. Boilers 1 and 2 added 1,882 tons of NO_x and 3,227 tons of SO_2 per unit to the 2018 inventory.
	Duke Murray (55382)	1	Corrected coordinates to 34.7189 and -84.9353
MS	R D Morrow ORISID=6061	1, 2	Revised the 2018 emissions to reflect controls not indicated by IPM. The SO_2 emissions are much lower than IPM, but their expected NO_x emissions are actually higher than IPM. The controls will be coming online 2009 or 2010, so the 2009 inventory did not change.
	Jack Watson (2049) Victor J Daniel (6073) Chevron Oil (2047)	All	MS DEQ specified that the emission projections provided by the Southern Company for their units in Mississippi were to be used instead of the IPM results.

Table 2.1-2 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
NC	G G Allen (2718) Belews Creek (8042)1 Buck (2720) Cliffside (2721) Dan River (2723) Marshall (2727) Riverbend (2732)	All	Replaced all IPM 2009 results with emission projections from Duke Power's NC Clean Air Compliance Plan for 2006. Used IPM results for 2018
	Asheville (2706) Cape Fear (2708) Lee (2709) Mayo (6250) Roxboro (2712) Sutton (2713) Weatherspoon (2716)	All	Replaced all IPM 2009 results with emission projections from Progress Energy's NC Clean Smokestacks Act Calendar Year 2005 Progress Report. Used IPM results for 2018, except for Lee #3* where IPM projected a retrofit scrubber but NC specified that no scrubber was to be applied.
	Dwayne Collier Battle Cogeneration Facility ORISID=10384	GEN1 GEN2	Dwayne Collier Battle is a duplicate entry. This is Cogentrix of Rocky Mount (37-065-3706500146, stacks G-26 and G-27). Duplicate entries were removed both the 2009 and 2018 inventories.
	Kannapolis Energy Partners ORISID=10626	GEN2 GEN3	Kannapolis Energy emissions are being used as credits for another facility. IPM emissions from this facility (37-025-ORIS10626) were removed from the EGU inventory for 2009 and 2018. Emissions from Kannapolis Energy (37-025-3702500113) were carried forward in the 2009/2018 inventory.
SC	Cross ORISID=130	1, 2	Unit 1: upgrade scrubber from 82 percent to 95 percent removal efficiency by June 30, 2006. Recalculate emissions based on upgrade in control efficiency. Unit 2: upgrade scrubber from 70 percent to 87 percent removal efficiency by June 30, 2006. Recalculate emissions based on upgrade in control efficiency.
	Winyah ORISID=6249	1 – 4	Unit 1: Install scrubber that meets 95 percent removal efficiency by Dec. 31, 2008; Upgrade ESP from 0.38 to 0.03 lb/mmBTU by Dec. 31, 2008 Unit 2: Replace scrubber with one that meets 95 percent removal efficiency from 45 percent by Dec. 31, 2008; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2008 Unit 3: Upgrade scrubber from 70 percent to 90 percent removal efficiency by Dec. 31, 2012; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2012 Unit 4: Upgrade scrubber from 70 percent to 90 percent removal efficiency by Dec. 31, 2007; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2007 Recalculated SO_2 and PM emissions based on upgrade in control efficiencies.

Table 2.1-2 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
SC	Dolphus Grainger ORISID=3317	1, 2	Unit 1: Upgrade ESP from 0.60 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 95 percent based on change in allowable emission rate Unit 2: Install low NO_x burners that meet 0.46 lb/mmBTU from 0.9 by May 1, 2004. Recalculated NO_x emissions using 0.46/lbs/mmBtu and IPM heat input Unit 2: Upgrade ESP from 0.60 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 95 percent based on change in allowable emission rate
	Jeffries ORISID=3319	3, 4	Unit 3: Upgrade ESP from 0.54 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 94.44 percent based on change in allowable emission rate Unit 4: Upgrade ESP from 0.54 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 94.44 percent based on change in allowable emission rate
	W S Lee ORISID=3264	1, 2	IPM does not indicate that these units are installing SOFA NO_x control technology by April 30, 2006 to meet 0.27 lb/mmBTU, down from 0.45 lb/mmBtu. Calculated NO_x emissions using IPM heat input and 0.27 lbs/mmBtu
	Generic Unit ORISID=900545	All	All predictions for generic units appear reasonable with the exception of Plant ID ORIS900545 Point ID GSC45 which was modeled in Georgetown County. It will be very difficult to add new generation this close to the Cape Romain Class I area. Santee Cooper has no plans for future generation in Georgetown County, but does have plans for new future generation in Florence County. This unit was moved to coordinates specified in Florence County.
VA	AEP Clinch River ORISID=3775	1, 2, 3	Used IPM results for 2009; replaced all 2018 IPM results with VADEQ's growth and control estimates (no SCR or scrubbers).
	AEP Glen Lyn ORISID=3776	51, 52, 6	Used 2009/2018 IPM results for units 51 and 52; used 2009 IPM for unit 6; replaced 2018 IPM for unit 6 with VADEQ's growth and control estimates (nor SCR or scrubber).
	Dominion Clover ORISID=7213	1, 2	Used 2009/2018 IPM results.
	Dominion Bremo ORISID=3796	3, 4	Used 2009/2018 IPM results.
	Dominion Chesterfield ORISID=3797	3, 4, 5, 6	Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Dominion Yorktown ORISID=3809	1, 2, 3	Units 1, 2: Used 2009/2018 IPM results for NOx and used VADEQ's growth and control estimates for SO2. Unit 3: IPM predicts zero heat input for this 880 MW #6 oil fired unit. Dominion plans to continue to operate Unit 3. Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.

Table 2.1-2 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
VA	Dominion Chesapeake ORISID=3803	1 – 4	Unit 1: Used 2009/2018 IPM for NOx; used 2009 IPM for SO2; used VADEQ's growth and control estimates for SO2 (added scrubber that IPM did not have) Unit 2: Used 2009/2018 IPM for NOx; used 2009 IPM for SO2; used VADEQ's growth and control estimates for SO2 (added scrubber that IPM did not have) Unit 3: Used VA DEQ's growth and control estimates for 2009 NOx (added SCR that IPM did not have); used IPM result for 2018 NOx; Used 2009/2018 IPM for SO2. Unit 4: Used VA DEQ's growth and control estimates for 2009 NOx (added SCR that IPM did not have); used IPM result for 2018 NOx; Used 2009/2018 IPM for SO2.
	Dominion Possum Point ORISID=3804	3 & 4 5 6	Unit 3&4: IPM had 137 tons of NO_x for these units in 2009 and 111 tons in 2018. VA DEQ specified that the permitted emission rates should be used, which equates to 3,066 tons in 2009 and 2018. Unit 5: IPM had zero heat input. Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates. Unit 6: Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Potomac River ORISID=3788	1 - 5	Units 1&2: IPM retired these units. Mirant has no plans at this time to retire any units. Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates. Units 3, 4, 5: Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
WV	Albright ORISID=3942	1, 2	IPM predicted early retirement for these units. AEP indicated there are no plans for early retirement. For 2009, used 2002 actual emissions as these units are not likely to retire by 2009. For 2018, used IPM prediction of retirement.
	Rivesville ORISID=3945	7, 8	IPM predicted early retirement for these units. AEP indicated there are no plans for early retirement. For 2009, used 2002 actual emissions as these units are not likely to retire by 2009. For 2018, used IPM prediction of retirement.
	Willow Island ORISID=3946	1, 2	Unit 1: IPM predicted early retirement for these units. AEP indicated there are no plans for early retirement. For 2009, used 2002 emissions as these units are not likely to retire by 2009. For 2018, used IPM prediction of retirement. Unit 2: IPM predicted SCR and scrubber for 2009. These controls will not be in place by 2009.
	North Branch ORISID=7537	1A, 1B	SO_2 Permit Rate was corrected from 2.7 to 0.678 lb/MMBtu. Used SO_2 Permit Rate and IPM predicted total fuel used to calculate SO_2 emissions in 2009 and 2018
	Mt. Storm ORISID=3954	1, 2, 3	SO_2 Permit Rate was corrected from 2.7 to 0.15 lb/MMBtu. Used SO_2 Permit Rate of 0.15 lb/MMBtu and IPM predicted total fuel used to calculate SO_2 emissions in 2009 and 2018
	Pleasants Power Station ORISID=6004	1, 2	IPM applied a scrubber with a 79.9% control efficiency; WV indicated that the control efficiency should be 95%.

2.1.1.8 S/L Adjustments to IPM Modeling Results for B&F Projections

For the B&F inventory, the S/L agencies were asked to review the Base G2 inventory with respect to the following items:

- Identify any updates needed to better reflect current information on when and where future controls would occur based on the best available data from state rules, enforcement agreements, compliance plans, permits, and discussions/commitments from individual companies;
- Identify any updates needed to change the IPM determination that most oil/gas steam units would either retire early or have no operation in 2009 or 2018; and
- Identify any updates needed to change the IPM assignment and VISTAS post-processing of generic units with specific information on new capacity.

The changes specified by the S/L agencies are summarized in Table 2.1-3. A comparison of the IPM and VISTAS control assumptions for all coal-fired EGUs in the B&F inventories are summarized in Appendix I.

Table 2.1-3 Additional Adjustments to IPM Results Specified by S/L Agencies for the B&F 2009/2018 EGU Inventories.

State	Plant Name and ID	Unit	Nature of Update/Correction
FL	Cape Canaveral Indian River Port Everglades Turkey Point Manatee Martin Riviera Anclote CD McIntosh Northside B Suwannee River	1, 2 1, 2, 3 1 – 4 1, 2 1, 2 1, 2 3, 4 1, 2 1 3 3	The IPM 2009/2018 solution has either shut-down these oil-fired units or converted them to natural gas only. FLDEP has reason to believe that these units may continue to operate using oil. For some of these units, the owner or operator of the units have provided (and FLDEP approved) an estimate of how the units will be operated in 2009/2018. For others, to be conservative, FLDEP assumed that the oil-fired units will operate in 2009/2018 exactly as they operated in 2002.
	Gulf Power Schultz ORISID=643	1 - 4	Plant is expected to shut down and was taken out of the 2018 projection.
	Northside ORISID=667	1A, 1B	These units were estimated to be non operational by IPM in 2009 and 2018. FLDEP believes these units will continue to operate. Emissions were estimated using the 2002 base case emissions and growth factors for Northside units 1A and 2A. The changes for 2009 were made in the B&F inventory; the changes for 2018 were made in the Base G2 inventory.
	Crist ORISID=641	4, 5 6, 7	IPM did not assign scrubbers to these units. Scrubbers are currently being installed and should be operational in 2009. SO2 emissions reduced by 90%.
GA	Mitchell ORISID=727	SG03	GADNR provided new emission projections for 2018.

Table 2.1-3 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
GA	Kraft ORISID=733	SG03	GADNR provided new emission projections for 2018.
	McIntosh ORISID=6124	SG01	GADNR provided new emission projections for 2018.
	Bowen ORISID=703	SG03 SG04	GADNR provided new SO2 emission projections for 2009 and 2018 based on a 95% control efficiency instead of 90%.
	Hammond ORISID=708	SG01 to SG04	GADNR provided new SO2 emission projections for 2009 and 2018 based on a 95% control efficiency instead of 90%.
	Wansley ORISID=6052	SG01	GADNR provided new SO2 emission projections for 2009 and 2018 based on a 95% control efficiency instead of 90%.
KY	John Sherman Cooper ORISID=1384	1	IPM did not assign a scrubber to this unit in 2018. KDAQ believes that a scrubber should be assigned for 2018.
	John Sherman Cooper ORISID=1384	2	IPM assigned SCR in 2009. KDAQ does not expect SCR by then; emissions changed to reflect low-NOx burner.
	Spurlock Station ORISID=6041	1, 2	IPM did not assign scrubbers to these units in 2009. Per a consent decree and for BART, KDAQ specified a 90% reduction in SO2 emissions from SO2 controls.
	Big Sandy ORISID=1353	BSU1	IPM assigned a scrubber and SCR in 2009. KDAQ does not expect scrubber or SCR controls to be operational in 2009.
MS	Entergy Delta Entergy Rex Brown Entergy Baxter Wilson Entergy Gerald Andrus	1, 2 3, 4 1, 2 1	The IPM 2009/2018 solution has either shut-down these oil-fired units or converted them to natural gas only. MSDEQ has reason to believe that these units may continue to operate using oil. To be conservative, MSDEQ assumed that the oil-fired units will operate in 2009/2018 exactly as they operated in 2002.
NC	Cliffside ORISID=2721	7	Removed Unit 7 from the 2018 inventory since the NC Utilities Commission disapproved the permit application.
	Cape Fear ORISID=2798	1, 2	IPM assigned scrubbers to both units in 2018; NCDENR indicated that the facility projected Furnace Sorbent Injection. Increased SO2 emissions to reflect change in control efficiency.
SC	99 Oil-fired Units		The IPM 2009/2018 solution has either shut-down 99 oil-fired units or converted them to natural gas only. SCDHEC has reason to believe that these units may continue to operate using oil. To be conservative, SCDHEC assumed that the oil-fired units will operate in 2009/2018 exactly as they operated in 2002.
SC	Santee Cooper Cross ORISID=130	4	For both 2009 and 2018, added in a new 660 MW Unit 4 (not in IPM) that is identical to the new Unit 3 (which was in IPM). Used the new Unit 4 to replace the IPM-generated 500 MW coal-fired Generic Unit (ORIS900545) located in the adjacent county.

Table 2.1-3 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
SC	New Santee Cooper Units Planned for Florence County	1, 2	Santee Cooper is planning two new coal burning units in Florence County, each at 660 MW. These units were not explicitly identified in IPM. Used these new units to replace three IPM-generated 500 MW coal-fired Generic Units (ORIS900145, ORIS900245, ORIS900345) in Darlington and Colleton Counties.
	USDOE SRS Area D ORISID=7652	1	Facility is replacing coal-fired boilers with three biomass boilers. Recalculated emissions for 2018 using emission factors for biomass combustion and IPM heat inputs.
VA	Dominion Chesapeake ORISID=3803	1 - 4	Changed SO2 emissions in 2009 and 2018 to reflect information from the facility on project SO2 controls.
	Dominion Southwest Virginia Project	1	For 2018, replace the IPM generated Generic Unit located in Russell county (ORISID=900251) to Wise County to reflect the planned Dominion facility going into Wise County. Used the potential to emit for the Dominion facility.
	Clinch River ORISID=3775	1, 2, 3	Changed emissions in 2018 to reflect requirements of Consent Order. The CO requires SNCR by 12/31/2009; IPM assigned SCR in 2018. The CO caps SO2 emissions at 16,300 tpy starting Jan 1, 2015.
WV	Pleasants Power Station ORISID=6004	1, 2	For both 2009 and 2018, Units 1 and 2 had SO2 emissions reduced to account for the facility's inclusion of previously bypassed 15% effluent stream to the scrubber. The control efficiency and emissions changed from 79.9% to 95% control.
	Nine Generic Units Generated by IPM		IPM placed 746 MW of new fossil fuel-fired generation in West Virginia - 173 MW coal-fired, 24 MW IGCC, and the remainder gas-fired. A 600 MW pulverized coal-fired EGU is under construction, scheduled to be online in 2010 [Longview]; a 98 MW CFB co-generation unit is permitted and expected to be built [Western Greenbrier]; and a 600 MW IGCC plant is currently in the permitting process [Mountaineer IGCC]. WVDEP decided to replace the IPM generic units in WV with the 3 units mentioned above.
	Longview Site ID: 54- 061-0134	1	For 2018 inventory, added Longview which is permitted, under construction, and scheduled to be online in 2010. The unit is a 600 MW pulverized coal-fired unit with baghouse, LNB, SCR, and wet FGD as required controls. Used permitted emission rates for 2018.
WV	Western Greenbriar Site ID: 54-025-0066	1	For 2018 inventory, added Western Greenbrier, which is permitted but not under construction. The unit is a 98 MW coal-fired CFB burning waste coal. Used permitted emission rates for 2018.
	Mountaineer IGCC Site ID: 54-053-00063	1	For 2018 inventory, added Mountaineer IGCC, which has applied for a permit to construct a nominal 600 MW IGCC. Used emission rates from the permit application for 2018.

2.1.1.9 Conversion of MRPO BaseM 2009 EGU Data to SMOKE Input Format

To support ASIP $PM_{2.5}$ CAMx modeling of the future year 2009, Alpine Geophysics obtained and processed an emission inventory for the 5 MRPO states (Illinois, Indiana, Michigan, Wisconsin, and Ohio). Appendix x details the technical steps that were made as part of the conversion of the MRPO BaseM EGU files into IDA format for ASIP PM-2.5 CAMx modeling of the future year 2009.

2.1.1.10 Summary of 2009/2018 EGU Point Source Inventories

Tables 2.1-4 through 2.1-10 compare the Base G 2002 base year inventory to the Base F, Base G/G2 and B&F 2009/2018 projection inventories. The Base F projections rely primarily on the results of the IPM, while the Base G and B&F projections include the adjustments to the IPM results specified by the S/L agencies in the previous section.

Table 2.1-4 EGU Point Source SO_2 Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	Actual Base G	Base F IPM Based	Base G IPM with State/local Updates	B&F IPM with Additional State/local Updates	Base F IPM Based	Base G2 IPM with State/local Updates	B&F IPM with Additional State/local Updates
AL	447,828	340,194	378,052	378,052	190,099	135,851	135,851
FL	453,631	195,790	186,055	291,831	141,551	138,340	194,028
GA	514,952	534,469	417,449	408,679	180,178	79,430	68,515
KY	484,057	371,944	290,193	271,669	229,603	226,062	222,102
MS	67,429	85,629	76,579	76,646	27,230	15,146	15,213
NC	477,990	205,018	242,286	242,286	110,382	114,771	120,165
SC	206,399	171,206	124,608	129,122	121,694	93,274	95,377
TN	334,151	255,400	255,410	255,410	112,662	112,672	112,672
VA	241,204	169,714	193,112	174,777	90,935	114,255	98,988
WV	516,084	226,127	277,489	268,952	124,466	105,935	106,199
	3,743,725	**2,555,491**	**2,441,233**	**2,497,423**	**1,328,800**	**1,135,736**	**1,169,110**

Note: Emission summaries above are based on SCCs 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-5 EGU Point Source NO_x Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	Actual Base G	Base F IPM Based	Base G IPM with State/local Updates	B&F IPM with Additional State/local Updates	Base F IPM Based	Base G2 IPM with State/local Updates	B&F IPM with Additional State/local Updates
AL	161,038	70,852	82,305	82,305	42,769	64,358	64,358
FL	257,677	89,610	86,165	132,535	77,080	74,640	87,645
GA	147,517	97,146	98,497	98,497	58,095	75,717	69,856
KY	198,817	107,890	92,021	97,263	64,378	64,378	64,378
MS	43,135	11,475	36,011	47,276	8,945	10,271	21,535
NC	151,853	66,431	66,522	66,521	60,914	62,353	61,110
SC	88,241	43,817	46,915	48,668	48,346	51,456	51,751
TN	157,307	41,767	66,405	66,405	31,725	31,715	31,715
VA	86,886	63,220	62,547	64,358	49,420	66,074	64,344
WV	230,977	63,510	86,328	85,476	51,241	51,241	51,474
	1,523,448	**655,718**	**723,717**	**789,304**	**492,913**	**552,203**	**568,166**

Note: Emission summaries above are based on SCCs 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-6 EGU Point Source VOC Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	Actual Base G	Base F IPM Based	Base G IPM with State/local Updates	B&F IPM with Additional State/local Updates	Base F IPM Based	Base G2 IPM with State/local Updates	B&F IPM with Additional State/local Updates
AL	2,295	2,441	2,473	2,473	2,952	2,952	2,952
FL	2,524	1,867	1,910	2,730	2,324	2,422	3,047
GA	1,244	1,571	2,314	2,314	1,903	2,841	2,816
KY	1,487	1,369	1,369	1,369	1,426	1,426	1,426
MS	648	406	404	564	1,124	1,114	1,274
NC	988	974	954	954	1,272	1,345	1,302
SC	470	660	660	723	906	906	931
TN	926	932	932	932	977	976	976
VA	754	685	778	788	903	1,014	980
WV	1,180	1,342	1,361	1,361	1,387	1,387	1,387
	12,516	**12,247**	**13,155**	**14,208**	**15,174**	**16,383**	**17,091**

Note: Emission summaries above are based on SCCs 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-7 EGU Point Source CO Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	Actual Base G	Base F IPM Based	Base G IPM with State/local Updates	B&F IPM with Additional State/local Updates	Base F IPM Based	Base G2 IPM with State/local Updates	B&F IPM with Additional State/local Updates
AL	11,279	14,948	14,986	14,986	24,342	24,342	24,342
FL	57,113	45,391	35,928	71,072	63,673	54,146	85,495
GA	9,712	20,066	23,721	23,721	32,744	44,476	44,269
KY	12,619	15,812	15,812	15,812	17,144	17,144	17,144
MS	5,303	5,078	5,051	7,116	15,364	15,282	17,348
NC	13,885	15,141	14,942	14,942	19,612	20,223	19,870
SC	6,990	11,135	11,135	11,643	14,786	14,786	14,975
TN	7,084	7,221	7,213	7,214	7,733	7,723	7,723
VA	6,892	11,869	12,509	12,535	14,755	15,564	18,850
WV	10,341	11,328	11,493	11,493	11,961	11,961	12,397
	141,218	**157,989**	**152,790**	**190,535**	**222,114**	**225,647**	**262,413**

Note: Emission summaries above are based on SCCs 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-8 EGU Point Source PM_{10}-PRI Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	Actual Base G	Base F IPM Based	Base G IPM with State/local Updates	B&F IPM with Additional State/local Updates	Base F IPM Based	Base G2 IPM with State/local Updates	B&F IPM with Additional State/local Updates
AL	7,646	6,959	6,969	6,969	7,822	7,822	7,822
FL	21,387	9,384	9,007	20,182	10,310	10,022	12,791
GA	11,224	17,088	17,891	17,891	18,329	20,909	20,732
KY	4,701	6,463	6,463	6,463	6,694	6,694	6,694
MS	1,633	5,487	4,957	5,182	7,624	7,187	7,412
NC	22,754	22,888	22,152	22,152	33,742	37,376	35,275
SC	21,400	28,650	19,395	20,041	37,864	28,826	27,640
TN	14,640	15,608	15,608	15,608	15,941	15,941	15,941
VA	3,960	4,479	5,508	5,606	12,744	13,832	12,551
WV	4,573	5,471	5,657	5,657	6,349	6,349	5,784
	113,918	**122,477**	**113,607**	**125,750**	**157,419**	**154,958**	**152,642**

Note: Emission summaries above are based on SCCs 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-9 EGU Point Source $PM_{2.5}$ -PRI Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	Actual Base G	Base F IPM Based	Base G IPM with State/local Updates	B&F IPM with Additional State/local Updates	Base F IPM Based	Base G2 IPM with State/local Updates	B&F IPM with Additional State/local Updates
AL	4,113	3,916	3,921	3,921	4,768	4,768	4,768
FL	15,643	6,250	5,910	14,790	7,171	6,886	9,417
GA	4,939	10,104	10,907	10,907	11,403	13,983	13,881
KY	2,802	4,279	4,279	4,279	4,434	4,434	4,434
MS	1,138	5,310	4,777	4,996	7,469	7,033	7,252
NC	16,498	16,514	15,949	15,949	26,966	29,792	28,137
SC	17,154	23,366	16,042	16,548	32,180	25,032	23,794
TN	12,166	13,092	13,092	13,092	13,387	13,387	13,387
VA	2,606	3,194	4,067	4,165	11,101	11,976	10,773
WV	2,210	2,850	2,940	2,940	3,648	3,648	3,116
	79,269	**88,875**	**81,884**	**91,587**	**122,527**	**120,939**	**118,959**

Note: Emission summaries above are based on SCCs 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-10 EGU Point Source NH_3 Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	Actual Base G	Base F IPM Based	Base G IPM with State/local Updates	B&F IPM with Additional State/local Updates	Base F IPM Based	Base G2 IPM with State/local Updates	B&F IPM with Additional State/local Updates
AL	317	359	359	359	1,072	1,072	1,072
FL	234	1,659	1,631	1,629	3,004	2,976	2,976
GA	83	686	686	686	1,677	1,677	1,677
KY	326	400	400	400	476	476	476
MS	190	333	333	334	827	827	827
NC	54	423	445	445	691	663	663
SC	142	343	343	370	617	617	625
TN	204	227	227	227	241	241	241
VA	127	632	694	694	558	622	606
WV	121	330	330	330	180	180	143
	1,798	**5,392**	**5,448**	**5,474**	**9,343**	**9,351**	**9,306**

Note: Emission summaries above are based on SCCs 1-01-xxx-xx and 2-01-xxx-xx.

2.1.2 Non-EGU Emission Projections

The general approach for assembling future year data was to use growth and control data consistent with the data used in EPA's Clean Air Interstate Rule analyses, supplement these data with available stakeholder input, and provide the results for stakeholder review to ensure credibility. We used the revised 2002 VISTAS base year inventory, based on the 2002 CERR submittals as the starting point for the non-EGU projection inventories. As described in Section 2.1.1.4, we split the point source inventory into EGU and non-EGU components. MACTEC performed the following activities to apply growth and control factors to the 2002 inventory to generate the 2009 and 2018 projection inventories:

- Obtained, reviewed, and applied the most current growth factors developed by EPA, based on forecasts from an updated Regional Economic Models, Inc. (REMI) model (version 5.5) and the latest *Annual Energy Outlook* published by the Department of Energy (DOE);
- Obtained, reviewed, and applied any State-specific or sector-specific growth factors submitted by stakeholders;
- Obtained and incorporated information regarding sources that have shut down after 2002 and set the emissions to zero in the projection inventories;
- Obtained, reviewed, and applied control assumptions for programs "on-the-books" and "on-the-way";
- Provided data files in NIF3.0 format and emission summaries in EXCEL format for review and comment; and
- Updated the database with corrections or new information from S/L agencies based on their review of the Base F 2009/2018 inventories.

The following sections discuss each of these steps.

2.1.2.1 Growth assumptions for non-EGU sources

This section describes the growth factor data used in developing the Base F inventory for 2009 and 2018, as well as the changes to the growth factor data made for the Base G inventory.

The growth factor data used in developing the Base F inventory were consistent with EPA's analyses for the CAIR rulemaking. These growth factors are fully documented in the reports entitled *Development of Growth Factors for Future Year Modeling Inventories* (dated April 30, 2004) and *CAIR Emission Inventory Overview* (dated July 23, 2004). Three sources of data were used in developing the growth factors for the Base F inventory:

- State-specific growth rates from the Regional Economic Model, Inc. (REMI) Policy Insight® model, Version 5.5 (being used in the development of the EGAS Version 5.0). The REMI socioeconomic data (output by industry sector, population, farm sector value

added, and gasoline and oil expenditures) are available by 4-digit SIC code at the State level.

- Energy consumption data from the DOE's Energy Information Administration's (EIA) *Annual Energy Outlook 2004, with Projections through 2025* for use in generating growth factors for non-EGU fuel combustion sources. These data include regional or national fuel-use forecast data that were mapped to specific SCCs for the non-EGU fuel use sectors (e.g., commercial coal, industrial natural gas). Growth factors for the residential natural gas combustion category, for example, are based on residential natural gas consumption forecasts that are reported at the Census division level. These Census divisions represent a group of States (e.g., the South Atlantic division includes eight southeastern States and the District of Columbia). Although one would expect different growth rates in each of these States due to unique demographic and socioeconomic trends, EIA's projects all States within each division using the same growth rate.
- Specific changes for sectors (e.g., plastics, synthetic rubber, carbon black, cement manufacturing, primary metals, fabricated metals, motor vehicles and equipment) where the REMI-based rates were unrealistic or highly uncertain. Growth projections for these sectors were based on industry group forecasts, Bureau of Labor Statistics (BLS) projections and Bureau of Economic Analysis (BEA) historical growth from 1987-2002.

In addition to the growth data described above, we received two sets of growth projections from VISTAS stakeholders.

The American Forest and Paper Association (AF&PA) supplied growth projections for the pulp and paper sector, which were applied to SIC 26xx Paper and Allied Products. The AF&PA projection factors are for the U.S. industry and apply to all States equally. The numbers come from the 15-year forecast for world pulp and recovered paper prepared by Resource Information Systems Inc. (RISI).

SIC Code	Sector	AF&PA Growth Factor	
		2002 to 2009	2002 to 2018
2611	Pulp Mills	1.067	1.169
2621	Paper Mills	1.067	1.169
2631	Paperboard Mills	1.067	1.169

For both the Base F and Base G inventories, we used the above AF&PA growth factors by SIC instead of the factors obtained from EPA's CAIR analysis.

For the Base F inventory, the NCDENR supplied recent projections for three key sectors in North Carolina where declining production was anticipated – SIC 22xx Textile Mill Products, 23xx Apparel and Other Fabrics, and 25xx Furniture and Fixtures. For the Base G inventory, NCDENR decided to use a growth factor of 1.0 for these SIC codes for both 2009 and 2018. Although NCDENR has data that shows a steady decline in these industries in NC, NCDENR wanted to maintain the emission levels at 2002 levels so the future emission reduction credits were available in the event that they are needed for nonattainment areas. The specific growth factors for these industrial sectors in North Carolina were:

NCDENR Growth Factors for Specific Industrial Sectors					
SIC Code	Industrial Sector	2009		2018	
		Base F	Base G	Base F	Base G
22xx	Textile Mill Products	0.6239	1.00	0.2792	1.00
23xx	Apparel and Other Fabrics	0.5867	1.00	0.2247	1.00
25xx	Furniture and Fixtures	0.8970	1.00	0.7647	1.00

For the Base G inventory, we made one additional change to the growth factors. The Base F inventory relied on DOE's AEO2004 forecasts for projecting emissions for fuel-burning SCCs (applies mainly to ICI boilers 1-02-xxx-xx and 1-03-xxx-xx, as well as in-process fuel use). We replaced the AEO2004 data with the more recent AEO2006 forecasts (released in February 2006) to reflect changes in the energy market and to improve the emissions growth factors produced. We obtained the corresponding AEO2006 projection tables from DOE's web site located at http://www.eia.doe.gov/oiaf/aeo/supplement/supref.html. We developed tables comparing the growth factors based on AEO2004 and AEO2006. These comparison tables were reviewed by the S/L agencies. Based on this review, VISTAS decided to use the AEO2006 growth factors for fuel burning SCCs.

We used the EPA's EGAS model and updated the corresponding AEO2006 projection tables to create growth factors by SCC. We applied the updated growth factors to 2002 actual emissions and replaced the 2009 and 2018 emissions in NIF EM tables for the affected SCCs.

2.1.2.2 Source Shutdowns

A few states indicated that significant source shutdowns have occurred since 2002 and that emissions from these sources should not be included in the future year inventories. These sources are identified in Table 2.1-11.

Table 2.1-11 Summary of Source Shutdowns Incorporated in Base G Inventory.

State	Description of Source Shutdowns
AL	None specified.
FL	The following facilities are shutdown and projected emissions were set to zero in 2009/2018. 0570075 CORONET INDUSTRIES, INC. 1050050 U S AGRI-CHEMICALS CORP. 1050051 U.S. AGRI-CHEMICALS CORPORATION These facilities emitted 2,417 tons of SO_2 and 113 tons of NO_x in 2002.
GA	Georgia indicated that the former Blue Circle (now LaFarge) facility in downtown Atlanta will likely shut down before 2009. The facility has two cement kilns, one of which is already shut down. The second kiln will continue to operate until the new facility in Alabama has enough milling capacity, after which the entire Atlanta facility will be completely closed down. This facility emitted 1,617 tons of SO_2 and 587 tons of NO_x in 2002.
KY	None specified.
MS	AF&PA indicated that the International Paper Natchez Mill (28-001-2800100010) has shut down. This facility emitted 1,398 tons of SO_2 and 1,773 tons of NO_x in 2002.
	The Magnolia Resources - Pachuta Harmony Gas Plant (28-023-00031) is out of business and no longer holds an air permit. This facility emitted 2,257 tons of $SO_2$and 134 tons of NO_x in 2002.
NC	In Base F, two paper mills were identified as being shut down in the 2018 inventory. NCDENR indicated that these mills are not expected to close. The two facilities are Ecusta Business Development (37-175-3717500056) and International Paper (37-083-00007). Their emissions were added back into the Base G 2018 inventory.
	BASF Corporation (37-021-724) in Buncombe County is currently operating but has plans to shut down in 2007. This facility emitted 461 tons of SO_2 and 266 tons of NO_x in 2002.
SC	South Carolina provided a list of facilities that were identified as closing down on or after Jan. 1, 2003. The emissions for these facilities were set to zero in the 2009 and 2018 projection inventories. Emissions from these plants in 2002 were: 6,195 tons of SO_2, 2,994 tons of NO_x, and 2,836 tons of VOC. Most of the emissions were from one facility – Celanese Acetate (45-091-2440-0010) in York County.
TN	Davidson County (Nashville) indicated that significant source shutdowns have occurred since data were submitted for the 2002 CERR. Source number 47-037-00002 (Dupont) shut down a portion of their facility, which was permanently taken out of service. Source 47-037-00050 (Nashville Thermal Transfer Corp.) shut down their municipal waste combustors and replaced them with natural gas fired boilers with propane stand by.
	Weyerhaeuser (AKA Willamette) Power Boiler 7 (47-163-0022, EU ID = 017) is being shut down. This emission unit emitted 4,297 tons of SO_2 and 1,443 tons of NO_x in 2002.
	Liberty Fibers (47-063-0197) in Hamblen County has recently shut down. This facility emitted 5,377 tons of SO_2; 2,057 tons of NO_x; and 9,059 tons of VOC in 2002.
VA	Rock-Tenn (51-680-00097) received a permit dated 9/13/2003 which required the shutdown of units 1 and 2 by 2/27/2004. This permit was part of a netting exercise that allowed the installation of a new NG/DO boiler. These two units emitted 507 tons of SO_2 and 276 tons of NO_x in 2002.
WV	None specified.

2.1.2.3 Control Programs applied to non-EGU sources

We used the same control programs for both the 2009 and 2018 non-EGU point inventory. Two control scenarios were developed: on-the-books (OTB) controls and on-the-way (OTW) controls. The OTB control scenario accounts for post-2002 emission reductions from promulgated federal, State, local, and site-specific control programs. The OTW control scenario accounts for proposed (but not final) control programs that are reasonably anticipated to result in post-2002 emission reductions. The methodologies used to account for the emission reductions associated with these emission control programs are discussed in the following sections.

Table 2.1-12 Non-EGU Point Source Control Programs Included in 2009/2018 Projection Inventories.

On-the-Books (Cut-off of July 1, 2004 for Base 1 adoption)

- Atlanta / Northern Kentucky / Birmingham 1-hr SIPs
- Industrial Boiler/Process Heater/RICE MACT (see Section 2.1.2.3.2)
- NO_x RACT in 1-hr NAA SIPs
- NO_x SIP Call (Phase I- except where States have adopted II already e.g. NC)
- Petroleum Refinery Initiative (October 1, 2003 notice; MS & WV)
- RFP 3 percent Plans where in place for one hour plans
- VOC 2-, 4-, 7-, and 10-year maximum achievable control technology (MACT0 Standards
- Combustion Turbine MACT

On-the-Way

- NO_x SIP Call (Phase II – remaining States & IC engines)

2.1.2.3.1 OTB - NO_x SIP Call (Phase I)

Phase I of the NO_x SIP call applies to certain large non-EGUs, including large industrial boilers and turbines, and cement kilns. States in the VISTAS region affected by the NO_x SIP call have developed rules for the control of NO_x emissions that have been approved by EPA. We reviewed the available State rules and guidance documents to determine the affected sources and ozone season allowances. We also obtained and reviewed information in the EPA's CAMD NO_x Allowance Tracking System – Allowances Held Report. Since these controls are to be in effect by the year 2007, we capped the emissions for NO_x SIP call affected sources at 2007 levels and carried forward the capped levels for the 2009/2018 future year inventories. Since the NO_x SIP call allowances are given in terms of tons per ozone season (5 month period from May to

September), we calculated annual emissions by multiplying the 5-month allowances by a factor of 12 divided by 5.

2.1.2.3.2 OTB - Industrial Boiler/Process Heater MACT

EPA anticipates reductions in PM and SO_2 as a result of the Industrial Boiler/Process Heater MACT standard. The methods used to account for these reductions are the same as those used for the CAIR analysis. Reductions were included for existing units firing solid fuel (coal, wood, waste, biomass) which had a design capacity greater than 10 mmBtu/hr. EPA prepared a list of SCCs for solid fuel industrial and commercial/ institutional boilers and process heaters. We identified boilers greater than 10 mmBtu/hr using either the boiler capacity from the VISTAS 2002 inventory, or if the boiler capacity was missing, a default capacity based on a methodology developed by EPA for assigning default capacities based on SCC. The applied MACT control efficiencies were 4 percent for SO_2 and 40 for percent for PM_{10} and PM2.5 to account for the co-benefit from installation of acid gas scrubbers and other control equipment to reduce HAPs. On June 8, 2007, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the NESHAP for Industrial, Commercial and Institutional Boilers and Process Heaters. VISTAS States decided to leave the emission reductions in place since they envision using a 112(j) strategy (e.g., the "MACT hammer") to obtain similar levels of control)

2.1.2.3.3 OTB - 2, 4, 7, and 10-year MACT Standards

Maximum achievable control technology (MACT) requirements were also applied, as documented in the report entitled *Control Packet Development and Data Sources*, dated July 14, 2004. The point source MACTs and associated emission reductions were designed from Federal Register (FR) notices and discussions with EPA's Emission Standards Division (ESD) staff. We did not apply reductions for MACT standards with an initial compliance date of 2001 or earlier, assuming that the effects of these controls are already accounted for in the 2002 inventories supplied by the States. Emission reductions were applied only for MACT standards with an initial compliance date of 2002 or greater.

2.1.2.3.4 OTB Combustion Turbine MACT

The projection inventories do not include the NO_x co-benefit effects of the MACT regulations for Gas Turbines or stationary Reciprocating Internal Combustion Engines, which EPA estimates to be small compared to the overall inventory.

2.1.2.3.5 OTB - Petroleum Refinery Initiative (MS and WV)

Three refineries in the VISTAS region are affected by two October 2003 Clean Air Act settlements under the EPA Petroleum Refinery Initiative. The refineries are: (1) the Chevron

refinery in Pascagoula, MS; (2) the Ergon refinery in Vicksburg, MS; and (3) the Ergon refinery in Newell, WV.

The first consent decree pertained to Chevron refineries in Richmond and El Segundo, CA; Pascagoula, MS; Salt Lake City, UT; and Kapolei, HI. Actions required under the Consent Decree will reduce annual emissions of NO_x by 3,300 tons and SO_2 by 6,300 tons. The consent decree requires a program to reduce NO_x emissions from refinery heaters and boilers through the installation of NO_x controls that meet at least an SNCR level of control. The refineries are to eliminate fuel oil burning in any combustion unit. The consent decree also requires reductions of NO_x and SO_2 from the fluid catalytic cracking unit and control of acid gas flaring incidents. The consent decree does not provide sufficient information to calculate emission reductions for the FCCU or flaring at the Pascagoula refinery. Therefore, we calculated a general percent reduction for NO_x and SO_2 by dividing the expected emission reductions at the five Chevron refineries by the total emissions from these five refineries (as reported in the 1999 NEI). This resulted in applying percent reductions of 45 percent for SO_2 and 28 percent for NO_x to FCCU and flaring emissions at the Chevron Pascagoula refinery.

The second consent decree pertained to the Ergon-West Virginia refinery in Newell, WV; and the Ergon Refining facility in Vicksburg, MS. The consent decree requires the two facilities to implement a 6-year program to reduce NO_x emission from all heaters and boilers greater than 40 mmBtu/hr, and to eliminate fuel oil burning in any combustion unit (except during periods of natural gas curtailment). Specifically, ultra low NO_x burners are required on Boilers A and B at Newell, a low NO_x-equivalent level of control for heater H-101 at Newell and heaters H-1 and H-3 at Vicksburg, and an ultra low NO_x burner level of control for heater H-451 at Vicksburg.

2.1.2.3.6 OTW - NO_x SIP Call (Phase II)

The final Phase II NO_x SIP call rule was finalized on April 21, 2004. States had until April 21, 2005, to submit SIPs meeting the Phase II NO_x budget requirements. The Phase II rule applies to large IC engines, which are primarily used in pipeline transmission service at compressor stations. We identified affected units using the same methodology as was used by EPA in the proposed Phase II rule (i.e., a large IC engine is one that emitted, on average, more than 1 ton per day during 2002). The final rule reflects a control level of 82 percent for natural gas-fired IC engines and 90 percent for diesel or dual fuel categories. As shown later in Table 2.1-12, several S/L agencies provided move specific information on the anticipated controls at the compressor stations. This information was used in the Base G inventory instead of the default approach used by EPA in the proposed Phase II rule.

2.1.2.3.7 Clean Air Interstate Rule

CAIR does not require or assume additional emission reductions from non-EGU boilers and turbines.

2.1.2.4 Quality Assurance steps

Final QA checks were run on the revised projection inventory data set to ensure that all corrections provided by the S/L agencies and stakeholders were correctly incorporated into the S/L inventories and that there were no remaining QA issues that could be addressed during the duration of the project. After exporting the inventory to ASCII text files in NIF 3.0, the EPA QA program was run on the ASCII files and the QA output was reviewed to verify that all QA issues that could be addressed were resolved

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, and to ensure that a full and complete inventory was developed for VISTAS. Quality assurance was an important component to the inventory development process and MACTEC performed the following QA steps on the point source component of the VISTAS revised 2002 base year inventory:

Facility level emission summaries were prepared and evaluated to ensure that emissions were consistent and reasonable. The summaries included base year 2002 emissions, 2009/2018 projected emissions accounting only for growth, 2009/2018 projected emissions accounting for both growth and emission reductions from OTB and OTW controls.

State-level non-EGU comparisons (by pollutant) were developed for the base year 2002 emissions, 2009/2018 projected emissions accounting only for growth, 2009/2018 projected emissions accounting for both growth and emission reductions from OTB and OTW controls.

Data product summaries and raw NIF 3.0 data files were provided to the VISTAS Emission Inventory Technical Advisor and to the Point Source, EGU, and non-EGU Special Interest Work Group representatives for review and comment. Changes based on these comments were reviewed and approved by the S/L point source contact prior to implementing the changes in the files.

Version numbering was used for all inventory files developed. The version numbering process used a decimal system to track major and minor changes. For example, a major change would result in a version going from Base F1 to Base F2.

2.1.2.5 Additional Base G Updates and Corrections

Table 2.1-13 summarizes the updates and corrections to the Base F inventory that were requested by S/L agencies and incorporated into the Base G 2009/2018 inventories.

Table 2.1-13 Summary of Updates and Corrections Incorporated into the Base G 2009/2018 Non-EGU Inventories.

State	Nature of Update/Correction
AL	Corrected the latitude and longitude for two facilities: Ergon Terminalling (Site ID: 01-073-010730167) and Southern Power Franklin (Site ID: 01-081-0036).
	Corrections to stack parameters at 10 facilities for stacks with parameters that do not appear to fall into the ranges typically termed "acceptable" for AQ modeling.
FL	Corrected 2009/2018 emission values for the Miami Dade RRF facility (Site ID: 12-086-0250348) based on revised 2002 emissions and application of growth control factors for 2009/2018.
GA	Hercules Incorporated (12-051-05100005) had an erroneous process id (#3) within emission unit id SB9 and was deleted. This removes about 6,000 tons of SO_2 from the 2009/2018 inventories.
	Provided a revised file of location coordinates at the stack level that was used to replace the location coordinated in the ER file.
	There are several sources that have updated their emissions from their BART eligible units. most of these changes were for fairly small (<50 tpy) sources.
NC	Made several changes to Base F inventory to correct the following errors: 1. Corrected emissions at Hooker Furniture (Site ID: 37-081-3708100910), release point G-29, to use the corrected values in 2002 and carry those same numbers through to 2009 and 2018 since NCDENR assumes zero growth for furniture industry. 2. Identified many stack parameters in the ER file that were unrealistic. Several have zero for height, diameter, gas velocity, and flow rate. NC used the procedures outlined in Section 8 of the document ""National Emission Inventory QA and Augmentation Report" to correct unrealistic stack parameters. 3. Identified truncated latitude and longitude values in Base F inventory. NC updated all Title V facility latitude and longitude that was submitted to EPA for those facilities in 2004. Smaller facilities with only two decimal places were not corrected. 4. Corrected 2018 VOC emissions for International Paper (3709700045) Emission Unit ID, G-12, to reflect changes to the 2002 inventory.
	There are three Transcontinental Natural Gas Pipeline facilities in NC that are subject to the NO_x SIP call. NCDENR took 2004 emissions and grew them to 2009 & 2018 and capped those units that are subject to the NO_x SIP Call Rule. These facility IDs are 37-057-3705700300, 37-097-3709700225, and 37-157-3715700131.
	NCDENR applied NO_x RACT to a two facilities located in the Charlotte nonattainment area. NCDENR provided 2009 & 2018 emissions for Philip Morris USA (37-025-3702500048) and Norandal USA (37-159-3715900057).
SC	Corrected PM species emission values. SC DHEC's initial CERR submittal reported particulate matter emissions using the PM-FIL, PM_{10}-FIL, and $PM_{2.5}$ -FIL pollutant codes. In August 2005, SC DHEC indicated that data reported using the PM-FIL, PM_{10}-FIL, and $PM_{2.5}$ -FIL pollutant codes should actually have been reported using the PM-PRI, PM_{10}-PRI, and $PM_{2.5}$ _PRI codes. MACTEC performed a subsequent PM augmentation in April 2006 using the revised pollutant codes. These changes were reflected in the Base G 2009/2018 emission inventory.
	Specified that the Bowater Inc. facility (45-091-2440-0005) in York County conducted an expansion in 2003/2004 and plans a future expansion. SC provided updated emissions for 2009 and 2018 for this facility.

Table 2.1-13. Continued.

State	Nature of Update/Correction
TN	Updated 2009/2018 emissions for Eastman Chemical (47-163-0003) based on final (Feb. 2005) BART rule.
	Updated 2009/2018 emission inventory for the Bowater facility (47-107-0012) based on the facility's updated 2002 emission inventory update.
	Replaced 2009/2018 data from Hamilton County, Tennessee, using data from Hamilton County's CERR submittal as contained in EPA's 2002 NEI (in Base F, the inventory for Hamilton County was based on the draft VISTAS 2002 inventory, which in turn was based on the 1999 NEI); applied growth and control factors to revised 2002 inventory to generate emission projections for 2009/2018.
	Updated 2009/2018 emissions for PCS Nitrogen Fertilizer LP (Site ID: 47-157-00146) based on the facility's updated 2002 emission inventory update.
	The 2002 NEI correctly reports the actual emissions for CEMEX (47-093-0008) after the NO_x SIP call. There is no reason to suspect that that rate would change in 2008, 2009, or 2018. Emissions for 2009/2018 were set equal to 2002 emissions.
	In the Base F 2009/2018 inventories, NO_x controls were applied for two units at Columbia Gulf Transmission (47-111-0004). There are no plans for controls at these units, EO3 and EO4. The assumed control efficiency of 82 percent was backed out in the 2009/2018 inventories.
VA	VADEQ provided 2009/2018 NO_x emission estimates for NO_x Phase II gas transmission sources at three Transco facilities (51-011-00011, 51-137-00027, 51-143-00120) which were used to replace the default NO_x Phase II control assumptions for these facilities.
	VADEQ provided updated 2009/2018 NO_x and SO_2 emissions based on new controls required by a November 2005 permit modification and netting exercise. The entire power plant facility is limited to 213 tons of NO_x and 107 tons of SO_2 per year. The permit also allowed the installation of 3 new boilers, also under the 213 tons of NO_x /year cap.
WV	Updated 2009/2018 emissions for Steel of West Virginia (Site ID: 54-011-0009) based on the facility's updated 2002 emission inventory update.
	Made changes to several Site ID names due to changes in ownership
	Base F emissions were much too high for Weirton Steel (54-021-0029). WV believes that the source is very unlikely to emit the NO_x SIP Call budgeted amounts in 2009 or 2018. WV provided revised emission estimates based on EGAS for 2009/2018.
	Made corrections to latitude/longitude and stack parameters at a few facilities for stacks with parameters that do not appear to fall into the ranges typically termed "acceptable" for AQ modeling.

2.1.2.6 Additional B&F Updates and Corrections

Table 2.1-14 summarizes the updates and corrections to the Base G non-EGU inventory that were requested by S/L agencies and incorporated into the B&F 2009/2018 non-EGU inventories. The changes were primarily related to better information on anticipated BART controls for specific facilities and emission units.

Table 2.1-14 Summary of Updates and Corrections Incorporated into the B&F 2009/2018 Non-EGU Inventories.

State	Nature of Update/Correction
AL	For 2018, incorporated emission changes due to BART controls at Exxon Mobil (Site ID: 01-053-0007), International Paper (Site ID: 01-079-0001), and Solutia (Site ID: 01-103-0010). International Paper (Site ID: 01-079-0001) Unit 004 to be shutdown in the 2018 inventory.
FL	For both 2009 and 2018, incorporated emission changes due to BART controls at Georgia Pacific (Site ID: 12-107-1070005) Unit 15.
MS	For 2018 only, changed SO2 emission estimate for Pursue Energy (Site ID: 28-121-00036) based on the facility's estimates of the gas reserve at the site.
	For 2018 only, changed emission estimates for all pollutants at several emission units at the Chevron Pascagoula Refinery (Site ID: 28-059-00058) to reflect BART source reductions.
SC	For both 2009 and 2018, identified 15 facilities that have permanently closed. Emissions from these facilities set to zero for all pollutants.
TN	For both 2009 and 2018, identified seven facilities that have permanently closed. Emissions from these facilities were set to zero for all pollutants.
	For both 2009 and 2018, identified three emission units that have permanently closed. Emissions from these units were set to zero for all pollutants. 47-009-0130-002 (APAC – TN, Inc.-Harrison Construction – Asphalt plant), 47-009-0130-003 (APAC – TN, Inc.-Harrison Construction – Asphalt crusher), and 47-139-0004-001 (Intertrade - Number 6 acid plant)
	The following individual source will be shut down in 2010: 47-001-0020-002 (DOE, Y-12 – Boilers 1-4). For the 2018 inventory only, emissions from this unit were set to zero for all pollutants.
	A portion of 47-163-0003-020101 (Eastman, B-83-1 Stoker Boilers). This source previously consisted of 14 boilers (Boilers 11-24). Boilers 11-17 have been removed from service. Emissions for both 2009 and 2018 were reduced by 26.64%, based on the portion of the heat input capacity that is being removed from service.
	SO2 emissions in 2018 from 47-163-0003-021520 (Eastman, B-253-1 Tangential PC Boilers) were reduced by 90% to reflect anticipated BART controls.
	Reduced SO2 emissions at 47-157-00475 (Lucite International) in Shelby County as a result of a consent decree with U.S. EPA.
VA	Changed SO2 emissions in 2009 and 2018 for thirteen facilities to reflect updated information from VADEQ regarding projected SO2 controls.
WV	Weirton Steel (54-029-00001) and Wheeling Pittsburgh Steel (54-009-00002) have undergone significant, permanent process changes since 2002. WV DEP staff have consulted with facility staff and determined that calendar year 2004 emissions represent a better basis for future year emissions estimates. Therefore, WVDEP compiled emissions data from the 2004 inventory for these sources and applied the most current VISTAS growth factors to estimate emissions in 2009 and 2018.

2.1.2.7 Conversion of MRPO BaseM 2009 non-EGU Data to SMOKE Input Format

To support ASIP $PM_{2.5}$ CAMx modeling of the future year 2009, Alpine Geophysics obtained and processed an emission inventory for the 5 MRPO states (Illinois, Indiana, Michigan, Wisconsin, and Ohio). Appendix x details the technical steps that were made as part of the conversion of the MRPO BaseM non-EGU files into IDA format for ASIP PM-2.5 CAMx modeling of the future year 2009.

2.1.2.8 Summary of the 2009/2018 non-EGU Point Source Inventories

Tables 2.1-15 through 2.1-21 summarize the revised 2009/2018 non-EGU point source inventories. The "growth only" column does not include the shutdowns (section 2.1.2.2) or control factors (section 2.1.2.3), only the growth factors described in section 2.1.2.1.

Table 2.1-15 Non-EGU Point Source SO_2 Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	**Base G**	**Base F**	**Base G**	**B&F**	**Base F**	**Base G**	**B&F**
AL	96,481	100,744	101,246	101,246	112,703	113,224	103,303
FL	65,090	68,549	65,511	62,651	79,015	75,047	71,810
GA	53,778	61,535	53,987	53,987	68,409	59,349	59,349
KY	34,029	35,470	36,418	36,418	38,806	40,682	40,682
MS	35,960	27,488	25,564	25,564	40,195	26,678	25,674
NC	44,123	48,751	42,536	42,536	50,415	46,314	46,314
SC	53,518	55,975	48,324	47,193	56,968	53,577	52,410
TN	79,604	89,149	70,678	64,964	96,606	77,247	56,682
VA	63,903	63,075	62,560	58,039	69,776	68,909	57,790
WV	54,070	54,698	55,973	55,598	60,137	62,193	61,702
	580,556	**605,434**	**562,797**	**548,196**	**673,030**	**623,220**	**575,716**

Note: Emission summaries above include all SCCs except 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-16 Non-EGU Point Source NO_x Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	**Base G**	**Base F**	**Base G**	**B&F**	**Base F**	**Base G**	**B&F**
AL	83,310	69,676	69,409	69,409	79,101	78,318	77,960
FL	45,156	44,859	46,020	47,125	50,635	51,902	52,959
GA	49,251	51,556	50,353	50,353	57,323	55,824	55,824
KY	38,392	36,526	37,758	37,758	40,363	41,034	41,034
MS	61,526	55,877	56,397	56,398	62,132	61,533	61,252
NC	44,929	44,877	34,767	34,768	47,200	37,801	37,802
SC	42,153	42,501	40,019	39,368	44,480	44,021	43,331
TN	64,344	63,431	57,883	57,514	70,313	63,453	62,519
VA	60,415	51,335	51,046	51,001	56,876	55,945	55,734
WV	46,612	40,433	38,031	38,023	44,902	43,359	43,280
	536,088	**501,071**	**481,683**	**481,715**	**553,325**	**533,190**	**531,695**

Note: Emission summaries above include all SCCs except 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-17 Non-EGU Point Source VOC Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	**Base G**	**Base F**	**Base G**	**B&F**	**Base F**	**Base G**	**B&F**
AL	47,037	46,660	46,644	46,644	54,268	54,291	54,290
FL	38,471	36,675	36,880	36,882	42,787	42,811	42,813
GA	33,709	34,082	34,116	34,116	40,267	40,282	40,282
KY	44,834	47,648	47,785	47,785	55,564	55,861	55,861
MS	43,204	37,921	37,747	37,747	45,769	45,338	45,335
NC	61,182	70,464	61,925	61,925	76,027	70,875	70,875
SC	38,458	38,273	35,665	34,403	44,545	43,656	41,987
TN	84,328	89,380	74,089	73,498	111,608	93,266	92,456
VA	43,152	43,620	43,726	43,725	53,065	53,186	53,186
WV	14,595	14,012	13,810	13,043	16,632	16,565	15,582
	448,970	458,735	432,387	429,768	540,532	516,131	512,667

Note: Emission summaries above include all SCCs except 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-18 Non-EGU Point Source CO Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	**Base G**	**Base F**	**Base G**	**B&F**	**Base F**	**Base G**	**B&F**
AL	174,271	176,899	180,369	180,369	194,280	201,794	201,663
FL	81,933	83,937	87,037	87,661	96,642	96,819	97,438
GA	130,850	147,362	147,427	147,427	168,570	167,904	167,904
KY	109,936	121,727	122,024	122,024	139,121	139,437	139,437
MS	54,568	58,023	57,748	57,749	67,764	66,858	65,884
NC	50,576	53,955	53,744	53,744	61,127	62,197	62,197
SC	56,315	62,144	60,473	59,934	71,318	68,988	68,415
TN	115,264	123,844	119,665	119,216	146,407	140,942	140,556
VA	63,796	67,046	68,346	68,326	74,364	76,998	76,846
WV	89,879	100,248	100,045	93,839	119,318	119,332	111,302
	927,388	**995,185**	**996,878**	**990,289**	**1,138,911**	**1,141,269**	**1,131,642**

Note: Emission summaries above include all SCCs except 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-19 Non-EGU Point Source PM_{10}-PRI Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	**Base G**	**Base F**	**Base G**	**B&F**	**Base F**	**Base G**	**B&F**
AL	25,240	25,450	25,421	25,421	29,973	29,924	29,889
FL	35,857	39,363	39,872	39,947	46,573	46,456	46,492
GA	21,610	23,509	23,103	23,103	27,781	27,273	27,273
KY	16,626	17,164	17,174	17,174	20,142	20,153	20,153
MS	19,472	19,200	19,245	19,244	22,952	22,859	22,837
NC	13,838	14,738	13,910	13,910	15,816	15,737	15,737
SC	14,142	17,631	13,370	12,959	20,197	15,139	14,674
TN	35,174	37,040	34,833	34,581	45,168	42,280	41,999
VA	13,252	13,043	13,048	13,046	15,150	15,112	15,111
WV	17,503	17,723	17,090	11,882	21,699	21,735	14,202
	212,714	224,861	217,066	211,267	265,451	256,668	248,367

Note: Emission summaries above include all SCCs except 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-20 Non-EGU Point Source PM25-PRI Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	**Base G**	**Base F**	**Base G**	**B&F**	**Base F**	**Base G**	**B&F**
AL	19,178	19,256	19,230	19,230	22,628	22,598	22,584
FL	30,504	33,387	33,946	34,019	39,436	39,430	39,486
GA	17,462	19,361	18,982	18,982	22,882	22,416	22,416
KY	11,372	11,680	11,686	11,686	13,734	13,739	13,739
MS	9,906	9,144	9,199	9,199	10,768	10,739	10,719
NC	10,500	11,192	10,458	10,458	11,927	11,825	11,825
SC	10,245	13,101	9,390	9,048	14,947	11,086	10,699
TN	27,807	29,302	27,577	27,367	35,750	33,532	33,293
VA	10,165	9,980	9,988	9,988	11,604	11,594	11,605
WV	13,313	13,364	12,769	7,638	16,474	16,516	9,124
	160,452	**169,767**	**163,225**	**157,615**	**200,150**	**193,475**	**185,490**

Note: Emission summaries above include all SCCs except 1-01-xxx-xx and 2-01-xxx-xx.

Table 2.1-21 Non-EGU Point Source NH_3 Emission Comparison for 2002/2009/2018.

	2002	2009			2018		
State	**Base G**	**Base F**	**Base G**	**B&F**	**Base F**	**Base G**	**B&F**
AL	1,883	2,132	2,132	2,132	2,464	2,464	2,464
FL	1,423	1,544	1,544	1,544	1,829	1,829	1,829
GA	3,613	3,963	3,963	3,963	4,799	4,797	4,797
KY	674	733	760	760	839	901	901
MS	1,169	667	668	668	761	764	764
NC	1,180	1,288	1,285	1,285	1,422	1,466	1,466
SC	1,411	1,578	1,578	1,578	1,779	1,779	1,779
TN	1,613	1,861	1,841	1,840	2,240	2,214	2,213
VA	3,104	3,050	3,049	3,045	3,613	3,604	3,604
WV	332	341	341	314	416	413	378
	16,402	**17,157**	**17,161**	**17,129**	**20,162**	**20,231**	**20,195**

Note: Emission summaries above include all SCCs except 1-01-xxx-xx and 2-01-xxx-xx.

2.2 Area Sources

This section describes the methodology used to develop the 2009 and 2018 projection Base F and Base G projection inventories. This section describes two approaches to these projections. Separate methods for projecting emissions were used for non-agricultural (stationary area) and agricultural area sources (predominantly NH_3 emissions). The two methods used for these sectors are described in the sections that follow.

2.2.1 Stationary area sources

The general approach used to calculate Base F projected emissions for stationary area sources was as follows:

1. Use the VISTAS Base F 2002 base year inventory as the starting point for projections.
2. MACTEC then worked with the VISTAS States (via the Stationary Area Source SIWG) to obtain any State specific growth factors and/or future controls from the States to use in developing the projections.
3. MACTEC then back calculated uncontrolled emissions from the Base F 2002 base year inventory based on existing controls reported in the 2002 Base F base year inventory.
4. Controls (including control efficiency, rule effectiveness and rule penetration) provided by the States or originally developed for use in estimating projected emissions for U.S. EPA's Heavy Duty Diesel (HDD) rulemaking emission projections and used in the Clean Air Interstate Rule (CAIR) projections were then used to calculate controlled emissions. State submitted controls had precedence over the U.S. EPA developed controls.
5. Growth factors supplied from the States or the U.S. EPA's CAIR emission projections were then applied to project the controlled emissions to the appropriate year. In some cases EGAS Version 5 growth factors were used if no growth factor was available from either the States or the CAIR growth factor files. The use of EGAS Version 5 growth factors was on a case-by-case basis wherever State-supplied or CAIR factors were not available for SCCs found in the 2002 Base F inventory. Use of the EGAS factors was necessitated due to the CERR submittals used in constructing the Base F 2002 inventory. Use of the CERR data resulted in SCCs that were not found in the CAIR inventory and if no State-supplied growth factor was provided required the use of an EGAS growth factor.
6. MACTEC then provided the final draft Base F projection inventory for review and comment by the VISTAS States.

For Base F stationary area sources, no State-supplied growth or control factors were provided. Thus for all of the sources in this sector of the inventory, growth and controls for Base F were

applied based on controls initially identified for the CAIR and growth factors identified for the CAIR projections.

For the Base G projections, the Base G 2002 base year inventory (see section 1.2.3) was used as a starting point. States provided some updated future controls but growth factors used were identical to those used for Base F. The revised controls for Base G were largely for new sources added as part of the 2002 Base F comments. The calculation of Base G projections was identical to the six steps outlined above with the exception of revisions made to prescribed fire for 2009 and 2018 and for the State of North Carolina. North Carolina provided 2009 and 2018 updated emission files used to update the emissions for each year for several source categories. However not all sources in the inventory were included in these NC updates. As a consequence, the final Base G 2009 and 2018 inventory for NC included emissions updated using the NC supplied files and emissions developed using growth and control factors as outlined above.

In a few cases, additional growth factors had to be added for source categories that had not initially been included in the Base F inventory. These growth factors were obtained from EGAS 5.0. Finally updates to growth factors from EGAS 5.0 were made for fuel fired emission sources. The updated growth factors reflected the most recent data from the Department of Energy's Annual Energy Outlook (AEO). These data were used to reflect changes in energy efficiency resulting from new or updated fuel firing technologies.

2.2.1.1 Stationary area source controls

The controls obtained by MACTEC for the HDD rulemaking were controls for the years 2007, 2020, and 2030. Since MACTEC was preparing 2009 and 2018 projections, control values for intermediate years were prepared using a straight line interpolation of control level between 2007 and 2020. The equation used to calculate the control level was as follows:

CE = (((2020 CE – 2007 CE)/13)*YRS) + 2007 CE

Where:

CE	=	Control Efficiency for either 2009 or 2018
2020 CE	=	HDD Control Efficiency value for 2020
2007 CE	=	HDD Control Efficiency value for 2007
13	=	Number of years between 2020 and 2007
YRS	=	Number of years beyond 2007 to VISTAS Projection year

For 2009 the value of YRS would be two (2) and for 2018 the value would be eleven (11). Control efficiency values were determined for VOC, CO and PM. Rule penetration values for each year in the HDD controls tables obtained by MACTEC were always 100 percent so those values were maintained for the VISTAS projections.

Prior to performing the linear interpolation of the controls, MACTEC evaluated controls from the CAIR projections (NOTE: Initially the controls came from the IAQTR projections, however the controls used in CAIR were virtually identical to those in IAQTR). Those controls appeared to be identical to those used for the HDD rulemaking. In addition, MACTEC received some additional information on some controls for area source solvents (email from Jim Wilson, E.H. Pechan and Associates, Inc. to Gregory Stella, VISTAS Emission Inventory Technical Advisor, 3/5/04) that were used to check against the controls in the HDD rulemaking files. Where those controls proved to be more stringent than the HDD values, MACTEC updated the control file with those values (which were then used in the interpolation to develop 2009 and 2018 values). Finally, for VOC the HDD controls were initially provided at the State-county-SCC level. However, upon direction from the VISTAS Emission Inventory Technical advisor, the VOC controls were consolidated at the SCC level and applied across all counties within the VISTAS region (email from Gregory Stella, Alpine Geophysics, 3/3/2004) to ensure that no controls were missed due to changes in county FIPS codes and/or SCC designations between the time the HDD controls were developed and 2002.

The equation below indicates how VOC emissions were projected for stationary area sources.

$$VOC_{2018} = VOC_{2002}\ x\left(1-\left(\frac{VOC\_CE_{2018}}{100}\right)\left(\frac{VOC\_RE_{2018}}{100}\right)\left(\frac{VOC\_RP_{2018}}{100}\right)\right)$$

Where:

VOC_{2018} = VOC emissions for 2018

VOC_{2002} = Uncontrolled VOC emissions for 2002

VOC_CE_{2018} = Control Efficiency for VOC (in this example for 2018)

VOC_RE_{2018} = Rule Effectiveness for VOC (in this example for 2018)

VOC_RP_{2018} = Rule Penetration for VOC (in this example for 2018)

A similar equation could be constructed for either PM or CO. It should be noted that the control efficiencies calculated based on the HDD rulemaking were only applied if they were greater than any existing 2002 base year controls. No controls were found for SO_2 or NO_x area sources.

In the pre-Base F 2018 emission estimates, an energy efficiency factor was applied to energy related stationary area sources. The energy efficiency factor was applied along with the growth factor to account for both growth and changes in energy efficiency. That factor was not applied to the Base F projections since information supplied by U.S. EPA related to the CAIR growth factors indicated that growth values for those categories were derived from U.S. Department of Energy (DOE) and were felt to account for changes in growth and projected energy efficiency. For the Base G inventory, these energy efficiency factors were re-instituted and used in conjunction with EGAS 5.0 growth factors in a manner identical to that used for the pre-Base F inventories. The energy efficiency factors were derived from U.S. DOE's Annual Energy Outlook report.

One significant difference between the Base F and Base G control factors was for counties and independent cities in northern Virginia. Several counties and independent cities in northern Virginia are subject to Ozone Transport Commission rules. For these counties and independent cities, controls for portable fuel containers, mobile equipment repair/refinishing, consumer products, solvent metal cleaning, and the architectural and industrial maintenance rules were added. The counties/independent cities (FIPS code) included in the changes for Base G were: Alexandria City (51510), Arlington (51013), Fairfax City (51600), Fairfax (51059), Falls Church City (51610), Fredericksburg City (51630), Loudoun (51107), Manassas City (51683), Manassas Park City (51685), Prince William County (51153), Spotsylvania (51177), and Stafford (51179). Not all OTC rules applied to all counties/cities.

2.2.1.2 Stationary area source growth

As indicated above, growth factors for the Base F and Base G 2009 and 2018 inventories were obtained from the U.S. EPA and are linear interpolations of the growth factors used for the Clean Air Interstate Rule (CAIR) projections. The growth factors for the CAIR obtained by MACTEC were developed using a base year of 2001 and provided growth factors for 2010 and 2015. MACTEC used the TREND function in Microsoft Excel™ to calculate 2002, 2009 and 2018 values from the 2001, 2010 and 2015 values. The TREND function provides a linear interpolation of intermediate values from a known series of data points (in this case the 2001, 2010 and 2015 values) based on the equation for a straight line. These values were calculated at the State and SCC level with the exception of paved road emissions (SCC = 2294000000). The growth factors for paved roads were available in the CAIR data set at the State, county and SCC level so they were applied at that level.

Prior to utilizing the growth factors from the CAIR projections, MACTEC confirmed that all SCCs found in the VISTAS 2002 base year inventory were in the CAIR file (for Base F the starting point was the version 3.1 2002 base year inventory, for Base G the starting point was the Base F 2002 base year inventory). Some SCCs were not found in the CAIR file. For those SCCs,

the growth factors used were derived in one of five ways. First where possible, they were taken from a beta version of EGAS 5.0. In other cases, the growth factor was set to one (i.e., no growth). In other cases, a similar SCC that had a CAIR growth factor was used. In a few cases a growth factor based on an average CAIR growth at the 6 digit SCC level was calculated. Finally a number of records used population as the growth surrogate. For the Base G inventory, CAIR growth factors for fuel fired area sources were replaced with EGAS 5.0 growth factors (used in conjunction with AEO fuel efficiency factors). A comment field in the growth factor file was used to mark those records that were not taken directly from the CAIR projection growth factors.

2.2.1.3 Differences between 2009/2018

Methodologically, there was no difference in the way that 2009 and 2018 emissions were calculated for stationary area sources. The individual control and growth factors were different (due to the linear interpolation used to calculate the values) but the calculation methods were identical. This applies to both Base F and Base G.

The only exception to this is for the State of North Carolina for Base G. North Carolina provided an emissions update file used to override calculated projections for a number of area source categories. The values in these files (provided for both 2009 and 2018) were used to overwrite the calculated projected emissions in the final NIF file.

2.2.2 Agricultural area sources

The general approach used to calculate projected emissions for agricultural area sources (predominantly NH_3 emission sources) was as follows:

1. MACTEC used the version 3.1 2002 base year inventory data (which was based on the CMU ammonia model version 3.6).

2. MACTEC worked with the VISTAS States (via the Agricultural Sources SIWG) to obtain any State specific growth and/or future controls from the States for agricultural sources.

3. Since the base year emissions were uncontrolled, and no future controls for these sources were identified, MACTEC projected the agricultural emissions using State-specific growth if available, otherwise the U.S. EPA's Interstate Air Quality Transport Rule (IAQTR)/Ammonia inventory was used to develop the growth factors used to project the revised 2002 base year inventory to 2009 or 2018. Since the IAQTR inventory was only used to construct growth factors rather than using the emissions directly, no updated growth factors were prepared from the CAIR inventory values.

4. MACTEC then provided the final draft inventory for review and comment by the VISTAS States.

No change in the agricultural area source emission projections were made between Base F and Base G other than the removal of wild animal and human perspiration as a result of their removal from the 2002 base year file for Base G.

2.2.2.1 Control assumptions for agricultural area sources

No controls were identified either by the individual VISTAS States or in the information provided in the EPA's IAQTR or CAIR Ammonia inventory documents. Thus all projected emissions for agricultural area sources represent simple growth with no controls.

2.2.2.2 Growth assumptions for agricultural area sources

Growth for several agricultural area source livestock categories was developed using the actual emission estimates developed by the EPA as part of the NEI. That work included projections for the years 2002, 2010, 2015, 2020, and 2030. The actual emissions themselves were not used other than to develop growth factors since the 2002 NEI upon which the growth projections were based was prepared prior to the release of the 2002 Census of Agriculture data which was included in the CMU model (version 3.6) used to develop the Base F 2002 VISTAS base year inventory. Thus VISTAS Agricultural Sources SIWG decided to use the NEI ammonia inventory projected emissions to develop the 2009 and revised 2018 growth factors used to project emission for VISTAS. Details on the NEI inventory and projections can be found at:

http://www.epa.gov/ttn/chief/ap42/ch09/related/nh3inventorydraft_jan2004.pdf. The actual data files for the projected emissions can be found at:

http://www.epa.gov/ttn/chief/ap42/ch09/related/nh3output01_23_04.zip.

In order to use the NEI projected emissions as growth factors, several steps were required. These steps were as follows:

1. NEI projected emissions were only available for the years 2002, 2010, 2015, 2020, and 2030, thus the first task was to calculate intermediate year emissions for 2009 and 2018. These values were calculated based on linear interpolation of the existing data.

2. Once the intermediate emissions were calculated, MACTEC developed emission ratios to provide growth factors for 2009 and 2018. Ratios of emissions were established relative to the 2002 NEI emissions.

3. Once the growth factors were established, MACTEC then evaluated whether or not all agricultural SCCs within the revised 2002 base year inventory had corresponding

growth factors. MACTEC established that not all SCCs within the base year inventory had growth factors. These SCCs fell into one of two categories:

b. SCCs that had multiple entries in the NEI but only a single SCC in the 2002 VISTAS base year inventory. The NEI was established using a process model and for some categories of animals, emissions were calculated for several aspects of the process. The CMU model version 3.6 which was the basis for the VISTAS 2002 Base F inventory did not use a process model. As a consequence a mapping of SCCs in the NEI projections and corresponding SCCs in the CMU inventory was made and for those SCCs an average growth factor was calculated from the NEI projections for use with the corresponding SCC in the CMU based 2002 Base F inventory.

c. There were also State, county, SCC trios in the 2002 VISTAS Base F inventory which had no corresponding emissions in the NEI files. For these instances, MACTEC first developed State level average growth factors from the NEI projections for use in growing these records. Even after developing State level average growth factors there were still some State/SCC pairs that did not have matching growth. For these records, MACTEC developed VISTAS regional average growth factors at the SCC level from the NEI data.

1. Once all of the growth factors were developed, they were used to project the emissions to 2009 and 2018. Growth factors were first applied at the State, county and SCC level. Then remaining records were grown with the State/SCC specific growth factors. Finally, any remaining ungrown records were projected at the SCC level using the VISTAS regional growth factor.

For the livestock categories, the NEI emission projections only had data for beef and dairy cattle, poultry and swine. Thus for other livestock categories and for fertilizers alternative growth factors were required.

The growth factors for other livestock categories and fertilizers were obtained from growth factors used for the IAQTR projections made by the U.S. EPA. The methodology for these categories was identical to that used for dairy, beef, poultry and swine with the exception that State/SCC and VISTAS/SCC growth factors were not required for these categories since the IAQTR data contained State, county and SCC level growth factors. The IAQTR data provided growth factors for 1996, 2007, 2010, 2015 and 2020. Linear interpolation was used to develop the growth factors for the intermediate years 2009 and 2018 required for the VISTAS projections.

There were a few exceptions to the methods used for projecting agricultural sources for the VISTAS projections. These exceptions were:

1. All swine emissions for North Carolina were maintained at 2002 levels for each projection year to capture a moratorium on swine production in that State.

2. Ammonia growth factors for a few categories (mainly feedlots) were assigned to be the same as growth factors for PM emissions from the NEI projections. This assignment was made because the CMU model showed emissions from these categories but the NEI projections did not show ammonia emissions but did show PM emissions.

3. No growth factors were found for horse and pony emissions. These emissions were held constant at 2002 levels.

There was no change in this method between Base F and Base G. Thus Base F and Base G agricultural emissions are the same in each inventory. Future efforts on the agricultural emissions category should look at any changes made to the CMU model to reflect the model farm approach used by EPA in their inventory plus any updated growth factors that may be more recent than the EPA inventory used to develop growth estimates for Base F/G.

2.2.2.2.1 Differences between 2009/2018

Methodologically, there was no difference in the way that 2009 and 2018 emissions were calculated for agricultural area sources. The growth factors were different (due to the linear interpolation used to calculate the values) but the calculation methods were identical. In addition there was no difference between Base F and Base G for this category. Thus Base F and Base G agricultural emissions are the same in each inventory.

Tables 2.2-1 show the differences between Base F and Base G emissions for all area sources (including agricultural sources but excluding fires) for the 2002 base year and 2009 and 2018 by State and pollutant.

Table 2.2-1 2002 Base Year Emissions and Percentage Difference for Base F and Base G (based on actual emissions).

Actual Area 2002 - Base G							
State	**CO**	**NH3**	**NOX**	**PM10-PRI**	**PM25-PRI**	**SO2**	**VOC**
AL	83,958	58,318	23,444	393,588	56,654	52,253	182,674
FL	71,079	37,446	28,872	443,346	58,878	40,491	404,302
GA	108,083	80,913	36,142	695,414	103,794	57,559	299,679
KY	66,752	51,135	39,507	233,559	45,453	41,805	95,375
MS	37,905	58,721	4,200	343,377	50,401	771	131,808
NC	345,315	161,860	36,550	280,379	64,052	5,412	237,926
SC	113,714	28,166	19,332	260,858	40,291	12,900	161,000
TN	89,828	34,393	17,844	212,554	42,566	29,917	153,307
VA	155,873	43,905	51,418	237,577	43,989	105,890	174,116
WV	39,546	9,963	12,687	115,346	21,049	11,667	60,443
Base F							
AL	83,958	59,486	23,444	393,093	73,352	47,074	196,538
FL	105,849	44,902	29,477	446,821	81,341	40,537	439,019
GA	107,889	84,230	36,105	695,320	133,542	57,555	309,411
KY	66,752	51,097	39,507	233,559	52,765	41,805	100,174
MS	37,905	59,262	4,200	343,377	63,135	771	135,106
NC	373,585	164,467	48,730	303,492	69,663	7,096	346,060
SC	113,714	29,447	19,332	260,858	51,413	12,900	187,466
TN	89,235	35,571	17,829	211,903	49,131	29,897	161,069
VA	155,873	46,221	51,418	237,577	52,271	9,510	129,792
WV	39,546	10,779	12,687	115,346	25,850	11,667	61,490
Percentage Difference (negative values means Base G increased from Base F)							
AL	0.00%	1.96%	0.00%	-0.13%	22.76%	-11.00%	7.05%
FL	32.85%	16.61%	2.05%	0.78%	27.62%	0.12%	7.91%
GA	-0.18%	3.94%	-0.10%	-0.01%	22.28%	-0.01%	3.15%
KY	0.00%	-0.07%	0.00%	0.00%	13.86%	0.00%	4.79%
MS	0.00%	0.91%	0.00%	0.00%	20.17%	0.00%	2.44%
NC	7.57%	1.59%	24.99%	7.62%	8.05%	23.74%	31.25%
SC	0.00%	4.35%	0.00%	0.00%	21.63%	0.00%	14.12%
TN	-0.67%	3.31%	-0.09%	-0.31%	13.36%	-0.07%	4.82%
VA	0.00%	5.01%	0.00%	0.00%	15.84%	-1013.45%	-34.15%
WV	0.00%	7.57%	0.00%	0.00%	18.57%	0.00%	1.70%

Table 2.2-2 2009 Projection Year Emissions and Percentage Difference for Base F and Base G (based on actual emissions).

Actual Area 2009 - Base G							
State	**CO**	**NH3**	**NOX**	**PM10-PRI**	**PM25-PRI**	**SO2**	**VOC**
AL	66,654	64,268	23,930	413,020	58,699	48,228	143,454
FL	57,011	38,616	28,187	503,230	64,589	36,699	420,172
GA	94,130	89,212	37,729	776,411	112,001	57,696	272,315
KY	57,887	53,005	42,088	242,177	46,243	43,087	94,042
MS	27,184	63,708	4,249	356,324	51,661	753	124,977
NC	301,163	170,314	39,954	292,443	69,457	5,751	187,769
SC	90,390	30,555	19,360	278,299	41,613	13,051	146,107
TN	74,189	35,253	18,499	226,098	44,124	30,577	154,377
VA	128,132	46,639	52,618	252,488	44,514	105,984	147,034
WV	31,640	10,625	13,439	115,089	20,664	12,284	55,288
Base F							
AL	68,882	65,441	26,482	411,614	76,248	17,818	157,405
FL	101,356	46,950	31,821	507,515	90,487	52,390	462,198
GA	103,579	92,838	38,876	776,935	146,691	57,377	294,204
KY	64,806	53,023	42,122	242,345	54,397	40,779	94,253
MS	37,161	64,289	4,789	356,516	65,321	637	125,382
NC	332,443	173,187	53,550	317,847	75,570	7,607	252,553
SC	95,826	31,966	20,852	278,852	54,230	12,945	176,104
TN	82,196	36,578	19,148	225,650	51,753	29,787	160,265
VA	133,738	49,173	53,344	252,924	54,587	10,619	120,022
WV	37,704	11,461	13,816	115,410	25,835	12,156	57,082
Percentage Difference (negative values means Base G increased from Base F)							
AL	3.24%	1.79%	9.64%	-0.34%	23.02%	-170.67%	8.86%
FL	43.75%	17.75%	11.42%	0.84%	28.62%	29.95%	9.09%
GA	9.12%	3.91%	2.95%	0.07%	23.65%	-0.56%	7.44%
KY	10.68%	0.03%	0.08%	0.07%	14.99%	-5.66%	0.22%
MS	26.85%	0.90%	11.27%	0.05%	20.91%	-18.10%	0.32%
NC	9.41%	1.66%	25.39%	7.99%	8.09%	24.41%	25.65%
SC	5.67%	4.41%	7.16%	0.20%	23.27%	-0.82%	17.03%
TN	9.74%	3.62%	3.39%	-0.20%	14.74%	-2.65%	3.67%
VA	4.19%	5.15%	1.36%	0.17%	18.45%	-898.09%	-22.51%
WV	16.08%	7.29%	2.73%	0.28%	20.02%	-1.06%	3.14%

Table 2.2-3 2018 Projection Year Emissions and Percentage Difference for Base F and Base G (based on actual emissions).

State	CO	NH3	NOX	PM10-PRI	PM25-PRI	SO2	VOC
Actual Area 2018 - Base G							
AL	59,626	71,915	25,028	445,256	62,323	50,264	153,577
FL	53,903	40,432	30,708	578,516	72,454	38,317	489,975
GA	93,827	99,885	41,332	880,199	123,704	59,729	319,328
KY	54,865	55,211	44,346	256,052	47,645	44,186	103,490
MS	22,099	69,910	4,483	375,495	53,222	746	140,134
NC	290,809	180,866	43,865	315,294	71,262	6,085	189,591
SC	83,167	33,496	20,592	304,251	44,319	13,457	161,228
TN	68,809	36,291	19,597	246,252	46,692	31,962	182,222
VA	121,690	50,175	56,158	275,351	46,697	109,380	150,919
WV	28,773	11,504	14,828	121,549	21,490	12,849	60,747
Base F							
AL	63,773	73,346	28,754	445,168	82,449	49,975	168,507
FL	100,952	49,889	35,047	582,832	101,872	59,413	533,141
GA	105,059	103,911	42,260	880,800	163,925	61,155	342,661
KY	65,297	55,356	45,597	256,544	57,110	42,326	102,117
MS	36,425	70,565	5,230	375,931	68,338	831	139,419
NC	327,871	184,167	60,073	345,275	85,018	8,273	234,207
SC	89,343	35,082	22,467	304,940	58,441	13,517	196,946
TN	81,242	37,812	20,928	245,893	55,712	31,047	188,977
VA	129,037	53,023	56,668	275,790	58,141	11,479	128,160
WV	36,809	12,390	15,079	121,964	27,088	13,450	62,164
Percentage Difference (negative values means Base G increased from Base F)							
AL	6.50%	1.95%	12.96%	-0.02%	24.41%	-0.58%	8.86%
FL	46.61%	18.96%	12.38%	0.74%	28.88%	35.51%	8.10%
GA	10.69%	3.87%	2.20%	0.07%	24.54%	2.33%	6.81%
KY	15.98%	0.26%	2.74%	0.19%	16.57%	-4.40%	-1.34%
MS	39.33%	0.93%	14.28%	0.12%	22.12%	10.19%	-0.51%
NC	11.30%	1.79%	26.98%	8.68%	16.18%	26.45%	19.05%
SC	6.91%	4.52%	8.34%	0.23%	24.16%	0.44%	18.14%
TN	15.30%	4.02%	6.36%	-0.15%	16.19%	-2.95%	3.57%
VA	5.69%	5.37%	0.90%	0.16%	19.68%	-852.83%	-17.76%
WV	21.83%	7.15%	1.66%	0.34%	20.66%	4.46%	2.28%

2.2.3 Changes to Prescribed Fire for 2009/2018 Base G

Just prior to release of version 3.1 of the VISTAS inventory several Federal agencies indicated that they had plans for increased prescribed fire burning in future years and that the "typical" fire inventory would likely not adequately capture those increases (memo from Bill Jackson and Cindy Huber, August 13, 2004). However data were not readily available to incorporate those changes up through the Base F inventory. As a consequence MACTEC worked with Federal Land Managers to acquire the data necessary to provide 2009 and 2018 specific projections for the prescribed fire component of the Base G fire inventory. The 2009 and 2018 projections developed using the method described below are being used by VISTAS as the 2009 and 2018

base case inventories for all States except FL. For FL the supplied data from the FLMs is not being used as FL felt that their data adequately reflected current and future prescribed burning practices. The "typical" fire projection is the 2002 base prescribed fire projection.

One of the biggest issues in preparing the projection was how best to incorporate the data. Two agencies submitted data: Fish and Wildlife Service (FWS) and Forest Service (FS). FWS submitted annual acreage data by National Wildlife Refuge (NWR) and county with estimates of acres burned per day for each NWR. FS provided fire-by-fire acreage estimates based on mapping projected burning acreage to current 2002 modeling days. However, FWS did not submit data for VISTAS original base year preparation process, thus there was no known FWS data in the 2002 actual or typical inventories. Thus MACTEC had to develop a method that could use the county level data submitted by FWS.

In addition, despite the fact that the FS submitted fire-by-fire data for the 2002 actual inventory and had mapped the projections to current burn days in the 2002 actual inventory, MACTEC could not do a simple replacement of those records with the 2009/2018 projections. This situation was created because several VISTAS States run a prescribed fire permitting program. To avoid double counting, only State data was used in those States for the 2002 actual inventory. Thus there were no Federal data in those States since the Federal data could have potentially duplicated State-supplied prescribed fire data. In VISTAS States without permit programs, the FS supplied data for 2002 was used and those records were marked in database. Thus for those States, the FS supplied 2009/2018 data could be directly substituted for the 2002 data.

The method used by MACTEC to include the FS data applied a county level data approach for FS data where a State had a prescribed fire permitting program and a fire-by-fire replacement for FS data in States without permit programs. MACTEC used a county level approach for all of the FWS data. The approach used for each data set is discussed below.

For the FWS data MACTEC summed the annual acres burned supplied by the FWS across all NWRs in a county. We then subtracted out 2002 acreage for that county from the FWS projected acreage annual total to avoid double counting. The remaining acreage was then multiplied by 0.8 to account for blackened acres instead of the total perimeter acres that were reported. The revised total additional FWS acreage was then added to the total county "typical" acreage to determine future acreage burned for either 2009 or 2018. MACTEC then allocated the increased acreage to current modeling days. The average daily acres burned data provided by FWS per NWR/county was used to allocate the acreage to the correct number of days required to burn all of the acres. Guidance supplied by FWS indicated that up to three times the average daily acres burned could potentially be allocated to any one day. Thus if the estimated acreage per day were 100 acres then up to 300 acres could actually be allocated to a particular day. This approach (use of up to three times the average daily acres burned) was used if there were an insufficient number of 2002

modeling days available to account for all of the acreage increase. MACTEC used an incremental approach to using the increase above the base average daily acres. First we used twice the average daily acreage if that was sufficient to completely allocate the increased acreage over the total number of days available. If that wasn't sufficient then we used three times the average daily acres burned to allocate the acreage. We applied the highest increases to days in the database that already had the highest acreage burned since we felt those days were most likely to represent days with representative conditions for conducting prescribed burns.

The approach used by MACTEC for the FS was slightly different. For States that had permit programs, we used similar approach to the FWS county level approach. First we summed the FS data at county level, we then added that value to the typical acreage and then we allocated the acres to current modeling days. The mapping to current modeling days was performed by Bill Jackson of the USFS and provided to MACTEC. For States that do not have a prescribed fire permit program, MACTEC simply replaced the current fire-by-fire records in the database with fire-by-fire records from the FS and recalculated emissions based on fuel model and fuel loading. We also applied the same 0.8 correction for blackened acres applied to all FS supplied acreage as the supplied values represented perimeter acres.

An additional problem with developing year-specific prescribed fire projections was how to adequately capture the temporal profile for those fires. In the 2002 actual fire inventory, fires occur on same days as state/FLM records. In the 2002 "typical" year inventory, fire acreage increased or decreased from acreage on the same fire days as were in the 2002 actual inventory, since the acres were simply increased for each day based on a multiplier used to convert from actual to typical.

When prescribed fires acreage was added to a future year, MACTEC added acreage to individual fire days proportional to the annual increase (if acreage on a day is 10 percent of annual, add 10 percent of projected increase to that same day).

The table below shows how the FWS data for Okefenokee NWR were allocated for 2009 for Clinch County (Okefenokee NWR is located in four different counties). You can see that the total additional acres for the Clinch County portion of Okefenokee NWR was 1,956 acres. Two hundred eighty (280) acres were the estimated average daily acres burned for that NWR/county combination. Thus to allocate the entire 1,956 acres would require almost 7 burn days (1,956 divided by 280). However only 5 burn days were found for Clinch County in the 2002 actual fire database. Thus we allocated twice the average acreage to the burn day with the most acres burned in the 2002 actual fire database (since our method allowed us to increase the average daily acres burned up to three times the recommended level). Thus the first burn day received 560 acres and all others received 280 except the final day which received 276 to make the total equal to the required 1,956 acres. The table also indicates that the increased acres burned

provided increases of from 10-48 percent in the acres burned on the individual burn days and an average of approximately 14 percent for the year as a whole.

CLINCH COUNTY	3/1/2002	4/1/2002	2/1/2002	1/1/2002	11/1/2002	12/1/2002	Total Annual
Acres (typical)	3,757	2,612	1,996	1,801	616	472	11,764
Add on FWS Projection	560	280	280	280	280	276	1,956
Total	4,316	2,891	2,276	2,080	895	747	13,720
Percent Increase	14.9%	10.7%	14.0%	15.6%	45.5%	58.5%	14.3%

The figure below shows the increases for prescribed burning in the four counties that comprise the Okefenokee NWR area (which also includes FS land). In this figure you can see the additional acreage added for the burn days from FWS and the individual day increases caused by projected increases in prescribed burning based on FS data. It should be noted that while the emissions represent 2009, all fire event dates listed are for 2002 to match up with the base year meteorology used in modeling exercises.

Table 2.2-4 shows the percentage difference between the 2009 and 2018 projections developed for Base F and Base G. Base G includes the revised prescribed burning estimates described above. Values are calculated using Base F as the basis for change, thus negative values imply an increase in emissions for Base G.

Figure 2.2-1 Prescribed Fire Projection for Okeefenokee NWR for 2009

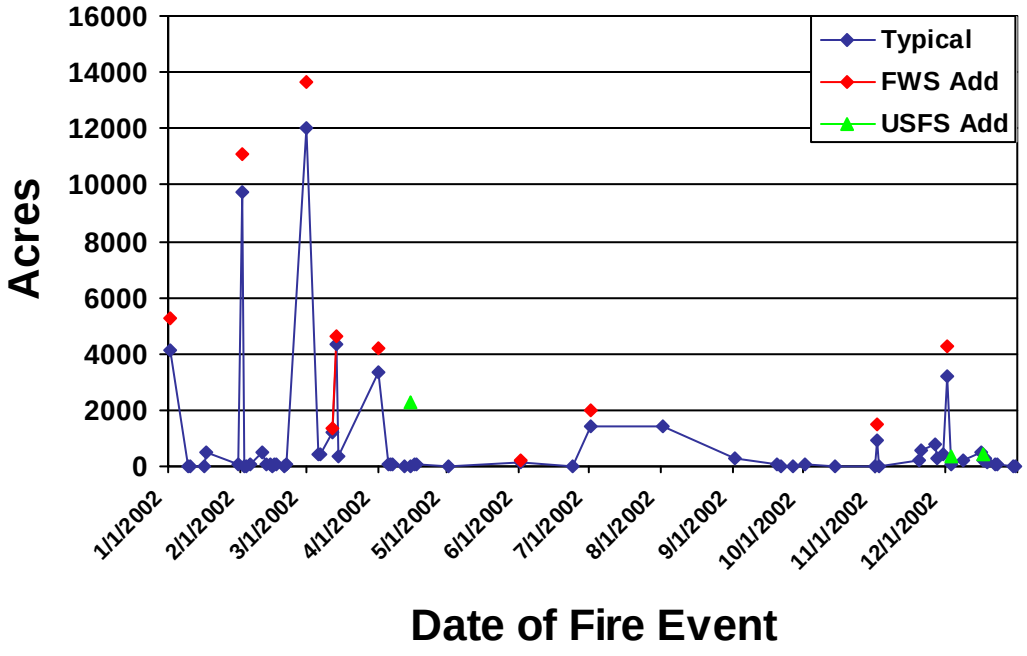


Table 2.2-4 Percentage Difference Between Base F and Base G Fire Emissions by State

State	CO	NH3	NOX	PM10-PRI	PM25-PRI	SO2	VOC	CO	NH3	NOX	PM10-PRI	PM25-PRI	SO2	VOC
2009 Fires Base G								**2018 Fires Base G**						
AL	534,873	2,050	11,901	52,851	46,543	2,681	27,502	535,658	2,054	11,918	52,927	46,608	2,686	27,539
FL	923,310	3,157	19,791	98,470	88,756	4,129	51,527	923,310	3,157	19,791	98,470	88,756	4,129	51,527
GA	637,177	2,229	14,243	63,973	57,116	2,914	34,710	637,177	2,229	14,243	63,973	57,116	2,914	34,710
KY	31,810	143	682	3,093	2,653	187	1,497	33,296	150	714	3,237	2,777	196	1,567
MS	48,160	217	1,033	4,683	4,016	283	2,266	50,037	225	1,073	4,865	4,173	294	2,355
NC	96,258	433	2,065	9,359	8,027	566	4,530	111,266	501	2,387	10,819	9,279	655	5,236
SC	282,307	1,039	5,899	29,153	25,955	1,359	16,045	282,307	1,039	5,899	29,153	25,955	1,359	16,045
TN	17,372	78	373	1,689	1,449	102	817	18,860	85	405	1,834	1,573	111	888
VA	21,130	95	453	2,054	1,762	124	994	26,923	121	578	2,618	2,245	158	1,267
WV	3,949	18	85	384	329	23	186	5,013	23	108	487	418	29	236
2009 Fires Base F								**2018 Fires Base F**						
AL	514,120	1,957	11,456	50,833	44,812	2,559	26,526	514,120	1,957	11,456	50,833	44,812	2,559	26,526
FL	923,310	3,157	19,791	98,470	88,756	4,129	51,527	923,310	3,157	19,791	98,470	88,756	4,129	51,527
GA	620,342	2,153	13,882	62,336	55,712	2,815	33,918	620,342	2,153	13,882	62,336	55,712	2,815	33,918
KY	56,686	110	1,460	6,667	6,310	136	3,338	56,686	110	1,460	6,667	6,310	136	3,338
MS	128,471	177	3,328	14,693	13,680	100	13,625	128,471	177	3,328	14,693	13,680	100	13,625
NC	200,564	324	5,005	20,488	19,491	423	12,499	200,564	324	5,005	20,488	19,491	423	12,499
SC	253,005	908	5,270	26,304	23,511	1,187	14,666	253,005	908	5,270	26,304	23,511	1,187	14,666
TN	78,370	46	2,232	8,875	8,730	59	5,153	78,370	46	2,232	8,875	8,730	59	5,153
VA	19,159	159	978	18,160	17,361	99	912	19,159	159	978	18,160	17,361	99	912
WV	32,656	12	944	3,276	3,239	16	2,184	32,656	12	944	3,276	3,239	16	2,184
Percentage Difference (negative number means an increase in Base G emissions)														
AL	-4.04%	-4.77%	-3.89%	-3.97%	-3.86%	-4.77%	-3.68%	-4.19%	-4.95%	-4.03%	-4.12%	-4.01%	-4.95%	-3.82%
FL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GA	-2.71%	-3.52%	-2.60%	-2.63%	-2.52%	-3.52%	-2.34%	-2.71%	-3.52%	-2.60%	-2.63%	-2.52%	-3.52%	-2.34%
KY	43.88%	-29.52%	53.25%	53.61%	57.96%	-37.90%	55.15%	41.26%	-35.57%	51.07%	51.44%	56.00%	-44.34%	53.06%
MS	62.51%	-22.07%	68.95%	68.13%	70.64%	-183.85%	83.37%	61.05%	-26.83%	67.74%	66.89%	69.50%	-194.91%	82.72%
NC	52.01%	-33.75%	58.74%	54.32%	58.82%	-33.75%	63.76%	44.52%	-54.60%	52.31%	47.19%	52.40%	-54.60%	58.11%
SC	-11.58%	-14.52%	-11.93%	-10.83%	-10.39%	-14.52%	-9.40%	-11.58%	-14.52%	-11.93%	-10.83%	-10.39%	-14.52%	-9.40%
TN	77.83%	-69.40%	83.30%	80.97%	83.41%	-74.42%	84.14%	75.93%	-83.92%	81.87%	79.34%	81.98%	-89.36%	82.78%
VA	-10.29%	40.36%	53.67%	88.69%	89.85%	-25.40%	-9.03%	-40.53%	24.00%	40.97%	85.59%	87.07%	-59.79%	-38.93%
WV	87.91%	-48.65%	91.03%	88.28%	89.83%	-49.46%	91.49%	84.65%	-88.70%	88.61%	85.12%	87.09%	-89.73%	89.20%

2.2.4 Quality Assurance steps

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, to ensure that a full and complete inventory was developed for VISTAS, and to make sure that projection calculations were working correctly. Quality assurance was an important component to the inventory development process and MACTEC performed the following QA steps on the stationary and agricultural area source components of the 2009 and revised 2018 projection inventories:

1. All final files were run through EPA's Format and Content checking software.
2. SCC level emission summaries were prepared and evaluated to ensure that emissions were consistent and that there were no missing sources.
3. Tier comparisons (by pollutant) were developed between the 2002 base year inventory and the 2009 and 2018 projection inventories. In addition, total VISTAS pollutant summaries were prepared to compare total emissions by pollutant between versions of the inventory (e.g., between Base F and Base G).
4. Data product summaries were provided to both the VISTAS Emission Inventory Technical Advisor and to the SIWG representatives for review and comment. Changes based on these comments were implemented in the files.
5. Version numbering was used for all inventory files developed. The version numbering process used a decimal system to track major and minor changes. For example, a major change would result in a version going from 1.0 to 2.0. A minor change would cause a version number to go from 1.0 to 1.1. Minor changes resulting from largely editorial changes would result in a change from 1.00 to 1.01.

2.3 Mobile Sources

Our general approach for assembling data was to use as much existing data from the pre-Base F preliminary projections as possible for these inventories, supplement these data with easily available stakeholder input, and provide the results for stakeholder review to ensure credibility. To develop the "base case" projections, MACTEC originally assembled data to develop two 2009 and 2018 base case inventories: 1) an inventory that included all "on-the-books" control programs and 2) an "on-the-way" inventory that included controls that were likely to be "on-the-way". For the Base F and Base G emission forecasts to the mobile source sector, "on-the-books" and "on-the-way" are defined with the same strategies and therefore only a single projection scenario was developed for each forecast year.

To ensure consistency across evaluation years, the 2009 and 2018 base case inventories were developed, to the maximum extent practical, using methodologies identical to those employed in

developing the 2002 on-road portion of the revised 2002 VISTAS base year inventory. All modifications to the 2002 inventory methods were developed in consultation with the Mobile Source Special Interest Workgroup (MSSIWG). Generally, modifications were only made to properly account for actual changes expected in the intervening period (i.e., between 2002 and 2009 and between 2002 and 2018), but the underlying inventory development methodology was identical, except to the extent requested by VISTAS or the MSSIWG.

MACTEC developed a preliminary 2018 inventory in early 2004. That inventory was designed to 1) be used for modeling sensitivity evaluations and 2) help establish the methods that would be used for the final 2018 inventory and the initial 2009 inventory. Since that work took place prior to the revision of the 2002 base year inventory data files, MACTEC provided a review of the data and methods used to develop on-road mobile source input files for the initial 2002 base year inventory prior to developing the preliminary 2018 inventory. Through this review, MACTEC determined the following:

- On-road VMT. Most States provided local data for 2002 (or a neighboring year that was converted to 2002 using appropriate VMT growth surrogates such as population). Since these data were not applicable to 2018 due to intervening growth, input for 2018 was solicited from the MSSIWG. At the same time we researched county-specific growth rate data utilized for recent national rulemakings as a backstop approach to State supplied VMT projections.
- Modeling Temperatures. Actual 2002 temperatures were used for the initial 2002 base year inventory.
- Vehicle Registration Mix (age fractions by type of vehicle). A mix of State, local, and MOBILE6 default data were used for the 2002 initial base year inventory. Forecast data were solicited from the States, with a fallback position that we hold the fractions constant at their 2002 values.
- Vehicle Speed by Roadway Type. For the 2002 initial base year inventory, speeds varying by vehicle and road type were used.
- VMT Mixes (fraction of VMT by vehicle type). A mix of State, local, and quasi MOBILE6 default (i.e., MOBILE6 defaults normalized to better reflect local conditions) data were used for the 2002 initial base year inventory. Forecast data were solicited from the States.
- Diesel Sales Fractions. As with the VMT mix data, the diesel sales fraction data employed for the 2002 initial base year inventory represents a mix of State, local, and quasi MOBILE6 default data. The issues related to updating these data to 2018 are also

similar, but are complicated by the fact that MOBILE6 treats diesel sales fraction on a model year, rather than age specific basis. Therefore, diesel sales fractions generally cannot be held constant across time. Once again, we solicited any local projections, with a fallback position that we would keep the data for 2002 and earlier model years constant for the forecast inventory, supplemented with MOBILE6 default data for 2003 and newer model years.

- State/Local Fuel Standards. For the 2002 initial base year inventory, these data were based on appropriate local requirements and updated data for 2018 was only required if changes were expected between 2002 and 2018. There are some national changes in required fuel quality for both on-road and non-road fuels that are expected to occur between 2002 and 2018 and these would be reflected in the 2018 inventory in the absence of more stringent local fuel controls. Expected changes in local fuel control programs were solicited.

- Vehicle Standards. The 2002 initial base year inventory assumed NLEV applicability. This was altered to reflect Tier 2 for 2018, unless a State indicated a specific plan to adopt the California LEV II program. If so, we made the required changes to implement those plans for the preliminary 2018 inventory.

- Other Local Controls. This includes vehicle emissions inspection (i.e., I/M) programs, Stage II vapor recovery programs, anti tampering programs, etc. By nature, the assumptions used for the 2002 initial base year inventory vary across the VISTAS region, but our presumption is that these data accurately reflected each State's situation as it existed in 2002. If a State had no plans to change program requirements between 2002 and 2018, we proposed to maintain the 2002 program descriptions without change. However, if a State planned changes, we requested information on those plans. In the final implementation of the Base F and earlier inventories, Stage II controls were exercised in the area source component of the inventory, since the units used to develop Stage II refueling estimates are different between MOBILE6 and the NONROAD models. However, in the Base G inventories, Stage II refueling was moved to the on-road and non-road sectors.

Once the preliminary 2018 (pre-Base F) base case projection inventory data were compiled, MACTEC applied the data and methods selected and proceeded to develop the preliminary (pre-base F) base case 2018 projection inventories. The resulting inventories were provided to the MSSIWG in a user-friendly format for review. After stakeholder review and comment, the final preliminary 2018 base case inventories and input files were provided to VISTAS in formats identified by the VISTAS Technical Advisor (in this case, MOBILE input files and VMT, NONROAD input files and annual inventory files for NONROAD in NIF 3.0 format). Annual

inventory files for MOBILE were not developed as part of this work, only input files and VMT forecasts. MOBILE emissions were calculated by VISTAS air quality modeling contractor using the provided files.

2.3.1 Development of on-road mobile source input files

As indicated above, MACTEC prepared a preliminary version of the 2018 base case mobile inventory input data files. These files were then updated to provide a final set of 2018 base case inventory input data files as well as a set of input files for 2009. The information below describes the updates performed on the preliminary 2018 files and the development of the 2009 input data files for Base F emission estimation.

Our default approach to preparing the revised 2018 and initial 2009 projection inventories for on-road mobile sources was to estimate the emissions by using either:

1. the revised 2002 data provided by each State coupled with the projection methods employed for the preliminary 2018 inventory, or
2. the same data and methods used to generate the preliminary 2018 inventory.

We also investigated whether or not there was more recent VMT forecasting data available (e.g., from the CAIR and if appropriate revised the default VMT growth rates accordingly. This did not affect any State that provided local VMT forecasting data, but would alter the VMT estimates used for other areas.

Since no preliminary 2009 inventory was developed there did not exist an option (2) above for 2009. As a consequence, MACTEC crafted the 2009 initial inventory for on-road mobile sources using methods identical to those employed for the 2018 preliminary inventories coupled with any changes/revisions provided by the States during the review of the revised 2002 base year and the 2018 preliminary inventories. Therefore, as was the case for 2018, we obtained from the States any input data revisions, methodological revisions, and local control program specifications (to the extent that they differed from 2002/2018).

2.3.1.1 Preparation of revised 2018 input data files

Preparation of the revised 2018 inventories required the following updates:

1. The evaluation year was updated to 2018 in all files.
2. The diesel fuel sulfur content was revised from 500 ppm to 11 ppm, consistent with EPA data for 2018 in all files.
3. Since the input data is model year, rather than age, specific for diesel sales fractions (with data for the newest 25 model years required), we updated all files that included

diesel sales fractions. In the revised 2002 base year files, the data included applied to model years 1978-2002. For 2018, the data included would reflect model years 1994-2018. To forecast the 2002 data, MACTEC took the data for 1994-2002 from the 2002 files and added data for 2003-2018. To estimate the data for these years, we employed the assumption employed by "default" in MOBILE6 -- namely that diesel sales fractions for 1996 and later are constant. Therefore, we set the diesel sales fractions for 2003-2018 at the same value as 2002.

4. VMT mix fractions must be updated to reflect expected changes in sales patterns between 2002 and 2018. If explicit VMT mix fractions are not provided, these changes are handled internally by MOBILE6 or externally through absolute VMT distributions. However, files that include explicit VMT mix fractions override the default MOBILE6 update and may or may not be consistent with external VMT distributions. MACTEC updated the VMT mix in such files as follows:

   First, we calculated the VMT fractions for LDV, LDT1, LDT2, HDV, and MC from the external VMT files for 2018. This calculation was performed in accordance with section 5.3.2 of the MOBILE6 Users Guide which indicates:

   LDV = LDGV + LDDV

   LDT1 = LDGT1 + LDDT

   LDT2 = LDGT2

   HDV = HDGV + HDDV

   MC = MC

   The resulting five VMT fractions were then split into the 16 fractions required by MOBILE6 using the distributions for 2018 provided in Appendix D of the MOBILE6 Users Guide. This approach ensures that explicit input file VMT fractions are consistent with the absolute VMT distributions prepared by MACTEC. These changes were made to all files that included VMT mixes.

5. All other input data were retained at 2002 values, except as otherwise instructed by the States. This includes all control program descriptions (I/M, Anti-Tampering Program [ATP], Stage II, etc.), all other fuel qualities (RVP, oxy content, etc.), all other vehicle descriptive data (registrations age distributions, etc.), and all scenario descriptive data. The State-specific updates performed are described below.

Kentucky:

MACTEC revised the 2018 input files for the Louisville, Kentucky area (Louisville Air Pollution Control District [APCD]) based on comments received relative to several components of

MOBILE input data. Based on these comments, the input files for Jefferson County, Kentucky were updated accordingly as follows:

a) I/M and tampering program definitions were removed since the program was discontinued at the end of 2003.

b) The "Speed VMT", "Facility VMT" and "Registration Age Distribution" file pointers were updated to reflect revised 2002 files provided by the Louisville APCD.

c) The "VMT Mix" data, which was previously based on the default approach of "growing" 2002 data, was replaced by 2018-specific data provided by the Louisville APCD.

North Carolina:

North Carolina provided a wide range of revised input data, including complete MOBILE6 input files for July modeling. MACTEC did not use the provided input files directly as they did not match the 2002 NC input files for critical elements such as temperature distributions and gasoline RVP (while they were close, they were slightly different). To maintain continuity between 2002 and 2018 modeling, MACTEC instead elected to revise the 2002 input files to reflect all control program and vehicle-related changes implied by the new 2018 files, while retaining the basic temperature and gasoline RVP assumptions at their 2002 values. Under this approach, the following changes were made:

a) NC provided a county cross reference file specific to 2018 that differed from that used for 2002. We removed files that were referenced in the 2002 input data and replaced those files with those referenced in the 2018 data. In addition, since NC only provided 2018 input files for July, we estimated the basic data for these new files for the other months by cross referencing the target files for 2002 by county against the target files for 2018 by county.

b) We then revised the 2002 version of each input file to reflect the 2018 "header" data included in the NC-provided 2018 files. These data are exclusively limited to I/M and ATP program descriptions, so that the 2002 I/M and ATP data were replaced with 2018 I/M and ATP data.

c) We retained the registration age fractions at their 2002 "values" (external file pointers) as per NC instructions.

d) We retained all scenario-specific data (i.e., temperatures, RVP, etc.) at 2002 values, which (as indicated above), were slightly different in most cases from data included in the 2018 files provided by NC. We believe these differences were due to small deviations between the data assembled to support VISTAS 2002 and the process used to generate the 2018 files provided by NC, and that revising the VISTAS 2002 data to

reflect these variations was not appropriate given the resulting inconsistencies that would be reflected between VISTAS 2002 and VISTAS 2018.

e) NC also provided non-I/M versions of the 2018 input files that would generally be used to model the non-I/M portion of VMT. While these files were retained they were not used for the 2018 input data preparation.

Finally, NC also provided a speed profile file and a speed profile cross reference file for 2018. We did not use these in our updates as they have no bearing on the MOBILE6 input files, but they were maintained in case they needed to be included in SMOKE control files for a future year control strategy scenario.

Virginia:

In accordance with instructions from VA, the input files that referenced an external I/M descriptive program file (VAIM02.IM) were revised to reference an alternative external file (VAIM05.IM). This change was to make the I/M program more relevant to the year 2018.

One additional important difference was made with respect to the revised 2018 and initial 2009 on-road mobile source input data files for all States. MACTEC developed updated SMOKE ready input files rather than MOBILE6 files so that the input data could be used directly by the VISTAS modeling contractor to estimate on-road mobile source emissions during modeling runs.

2.3.1.2 Preparation of initial 2009 input data files

The methodology used to develop the 2009 on-road input files was based on forecasting the previously developed revised 2002 base year input files and is identical to that previously described for the revised 2018 methodology except as follows:

1. The evaluation year was updated to 2009.
2. Diesel fuel sulfur content was revised from 500 ppm to 29 ppm. The 29 ppm value was derived from an EPA report entitled "Summary and Analysis of the Highway Diesel Fuel 2003 Pre-compliance Reports" (EPA420-R-03-013, October 2003), which includes the Agency's estimates for the year-to-year fuel volumes associated with the transition from 500 ppm to 15 ppm diesel fuel. According to Table 2 of the report, there will be 2,922,284 barrels per day of 15 ppm diesel distributed in 2009 along with 110,488 barrels per day of 500 ppm diesel. Treating the 15 ppm diesel as 11 ppm on average (consistent with EPA assumptions and assumptions employed for the 2018 input files) and sales weighting the two sulfur content fuels results in an average 2009 diesel fuel sulfur content estimate of 29 ppm.

3. Diesel sales fractions were updated identically to 2018 except that the diesel sales fractions for 2003-2009 were set at the same value as those for 2002 (rather than 2003-2018).

4. VMT mix fractions were updated to 2009 using an identical method to that described for 2018.

5. All other input data were retained at 2002 values, except as otherwise instructed by individual States (see below). This includes all control program descriptions (I/M, ATP, Stage II, etc.), all other fuel qualities (RVP, oxy content, etc.), all other vehicle descriptive data (registration age distributions, etc.), and all scenario descriptive data.

In addition to the updates described above that were applied to all VISTAS-region inputs, the following additional State-specific updates were performed:

KY – Identical changes to those made for 2018 (but specific to 2009) were made for the 2009 input files.

NC – Identical changes to those made for 2018 (but specific to 2009) were made for the 2009 input files.

VA – Identical changes to those made for 2018 were made for 2009.

2.3.2 VMT Data

The basic methodology used to generate the 2009 and 2018 VMT for use in estimating on-road mobile source emissions was as follows:

1. All estimates start from the final VMT estimates used for the 2002 revised base year inventory.

2. Initial 2009 and 2018 VMT estimates were based on linear growth rates for each State, county, and vehicle type as derived from the VMT data assembled by the U.S. EPA for their most recent HDD (heavy duty diesel) rulemaking. The methodology used to derive the growth factors is identical to that employed for the preliminary 2018 VMT estimates (which is described in the next section).

3. For States that provided no independent forecast data, the estimates derived in step 2 are also the final estimates. These States are: Alabama, Florida, Georgia, Kentucky, Mississippi, and West Virginia. For States that provided forecast data, the provided data were used to either replace or augment the forecast data based on the HDD rule. These States, and the specific approaches employed, are detailed following the growth method description.

The steps involved in performing the growth estimates for VMT were as follows:

1. Linear growth estimates were used (although MACTEC investigated the potential use of nonlinear factors and presented that information to the MSSIWG, the decision was made to use linear growth factors instead of nonlinear).

2. Estimates were developed at the vehicle class (i.e., LDGV, LDGT1, LDGT2, etc.) level of detail since the base year 2002 estimates were presented at that level of resolution. In effect, the county and vehicle class specific growth factors were applied to the 2002 VMT estimates for each vehicle and road class.

3. Overall county-specific VMT estimates for each year (developed by summing the vehicle and road class specific forecasts) were then compared to overall county-specific growth. Since overall county growth is a more appropriate controlling factor as it includes the combined impacts of all vehicle classes, the initial year-specific vehicle and road class VMT forecasts were normalized so that they matched the overall county VMT growth. Mathematically, this process is as follows:

$$(Est\_rv\_f) = (Est\_rv\_i) * (C\_20XX / Sum(Est\_rv\_i))$$

where:

Est_rv_f = the final road/vehicle class-specific estimates,

Est_rv_i = the initial road/vehicle class-specific estimates, and

C_20XX = the county-specific growth target for year 20XX.

Table 2.3-1 presents a basic summary of the forecasts for the preliminary 2018 inventory for illustrative purposes:

Table 2.3-1 2002 versus 2018 VMT (million miles per year)

State	2002	2018	Growth Factor
Alabama	55,723	72,966	1.309
Florida	178,681	258,191	1.445
Georgia	106,785	148,269	1.388
Kentucky	51,020	66,300	1.299
Mississippi	36,278	46,996	1.295
North Carolina	80,166	110,365	1.377
South Carolina	47,074	63,880	1.357
Tennessee	68,316	91,647	1.342
Virginia	76,566	102,971	1.345
West Virginia	19,544	24,891	1.274

The following States provided some types of forecast data for VMT. The information presented below indicates how those data were processed by MACTEC for use in the VISTAS projection inventories.

Kentucky:

Revised 2009 and 2018 VMT mix data were provided by the Louisville APCD. Therefore, the distribution of Jefferson County VMT by vehicle type within the KY VMT file was revised to reflect the provided mix. This did not affect the total forecasted VMT for either Jefferson County or the State, but does alter the fraction of that VMT accumulated by each of the eight vehicle types reflected in the VMT file. The following procedure was employed to make the VMT estimates consistent with the provided 2009/2018 VMT mix:

a) The 16 MOBILE6 VMT mix fractions were aggregated into the following five vehicle types: LDV, LDT1, LDT2, HDV, and MC.

b) The 8 VMT mileage classes were aggregated into the same five vehicle types (across all roadway types) and converted to fractions by normalizing against the total Jefferson County VMT.

c) The ratio of the "desired" VMT fraction (i.e., that provided in the Louisville APCD VMT mix) to the "forecasted" VMT fraction (i.e., that calculated on the basis of the forecasted VMT data) was calculated for each of the five vehicle classes.

d) All forecasted VMT data for Jefferson County were multiplied by the applicable ratio from step c as follows:

new LDGV = old LDGV * LDV ratio
new LDGT1 = old LDGT1 * LDT1 ratio
new LDGT2 = old LDGT2 * LDT2 ratio
new HDGV = old HDGV * HDV ratio
new LDDV = old LDDV * LDV ratio
new LDDT = old LDDT * LDT1 ratio
new HDDV = old HDDV * HDV ratio
new MC = old MC * MC ratio

The total forecasted VMT for Jefferson County was then checked to ensure that it was unchanged.

North Carolina:

North Carolina provided both VMT and VMT mix data by county and roadway type for 2018. Therefore, these data replaced the data developed for North Carolina using HDD rule growth

rates in their entirety. Similar data were submitted for 2009. Table 2.3-2 presents the resulting VMT estimates which differ from the "default" HDD rule estimates as follows:

Table 2.3-2 VMT and HDD Rule Estimates for North Carolina (million miles per year)

North Carolina		
2002	106,795	
	State Data	**HDD Data**
2009	123,396	124,626
2018	129,552	146,989

As indicated, there are substantial reductions in the State-provided forecast data relative to that derived from the HDD rule. The growth rates for both 2009 and 2018 are only about half that implied by the HDD data (1.15 versus 1.17 for 2009 and 1.21 versus 1.38 for 2018). The resulting growth rates are the lowest in the VISTAS region.

NC did not provide VMT mix data for 2009. Therefore, the VMT mix fractions estimated using the "default" HDD rule growth rates were applied to the State-provided VMT estimates to generate vehicle-specific VMT. Essentially, the default HDD methodology produces VMT estimates at the county-road type-vehicle type level of detail, and these data can be converted into VMT fractions at that same level of detail. Note that these are not HDD VMT fractions, but VMT fractions developed from 2002 NC data using HDD vehicle-specific growth rates. In effect, they are 2002 NC VMT fractions "grown" to 2009.

The default VMT mix fraction was applied to the State-provided VMT data at the county and road type level of detail to generate VMT data at the county-road type-vehicle type level of detail. The one exception was for county 063, road 110, for which no VMT data were included in the HDD rule. For this single county/road combination, State-aggregate VMT mix fractions (using the HDD growth methodology) were applied to the county/road VMT data. The difference between road 110 VMT fractions across all NC counties is minimal, so there is no effective difference in utilizing this more aggregate approach vis-à-vis the more resolved county/road approach.

South Carolina:

South Carolina provided county and roadway type-specific VMT data for several future years. Data for 2018 was included and was used directly. Data for 2009 was not included, but was linearly interpolated from data provided for 2007 and 2010. The data were disaggregated into vehicle type-specific VMT using the VMT mixes developed for South Carolina using the HDD rule VMT growth rates. Table 2.3-3 presents the resulting VMT estimates which differ from the "default" HDD rule estimates as follows:

Table 2.3-3 VMT and HDD Rule Estimates for South Carolina (million miles per year)

South Carolina		
2002	**47,074**	
	State Data	**HDD Data**
2009	55,147	54,543
2018	65,133	63,880

Tennessee:

In general, Tennessee estimates are based on the HDD rule growth rate as described in step two. However, Knox County provided independent VMT estimates for 2018 and these were used in place of the HDD rule-derived estimates. The Knox County estimates were total county VMT data only, so these were disaggregated into roadway and vehicle-type VMT using the distributions developed for Knox County in step two using the HDD rule VMT growth rates. No data for Knox County were provided for 2009, so the estimates derived using the HDD rule growth factors were adjusted by the ratio of "Knox County provided 2018 VMT" to "Knox County HDD Rule-derived 2018 VMT." Table 2.3-4 presents the resulting VMT estimates which differ from the "default" HDD rule estimates as follows:

Table 2.3-4 VMT and HDD Rule Estimates for Tennessee (million miles per year)

Tennessee		
2002	68,316	
	State Data	**HDD Data**
2009	78,615	78,813
2018	91,417	91,647

Virginia:

Virginia provided county and roadway type-specific annual VMT growth rates and these data were applied to Virginia -provided VMT data for 2002 to estimate VMT in both 2009 and 2018. Virginia provided VMT mix data for 2002, but not 2009 or 2018. Therefore, the estimated VMT data for both 2009 and 2018 were disaggregated into vehicle type-specific VMT using the VMT mixes developed for VA using the HDD rule VMT growth rates. Table 2.3-5 presents the resulting VMT estimates which differ from the "default" HDD rule estimates as follows:

Table 2.3-5 VMT and HDD Rule Estimates for Virginia (million miles per year)

Virginia		
2002	77,472	
	State Data	**HDD Data**
2009	88,419	89,196
2018	104,944	104,164

2.3.3 Base G Revisions

For the development of the VISTAS 2009 and 2018 Base G inventories and input files, VISTAS states reviewed the Base F inputs, and provided corrections, updates and supplemental data as noted below.

For all states modeled, the Base G updates include:

- Adding Stage II refueling emissions calculations to the SMOKE processing.
- Revised the HDD compliance. (REBUILD EFFECTS = .1)
- Revised Diesel sulfur values in 2009 to 43 ppm and 2018 to 11 ppm

In addition to the global changes, individual VISTAS states made the following updates:

KY – updated VMT and M6 input values for selected counties

NC – revised VMT estimates, speeds and vehicle distributions and updated registration distributions for Mobile 6.

TN - revised VMT and vehicle registration distributions for selected counties.

WV – revised VMT input data

AL, FL, and GA and VA did not provide updates for 2009/2018 Base G, and the Base F inputs were used for these States.

2.3.4 Development of non-road emission estimates

The sections that follow describe the projection process used to develop 2009 and 2018 non-road projection estimates, as revised through the spring of 2006, for sources found in the NONROAD model and those sources estimated outside of the model (locomotives, airplanes and commercial marine vessels).

2.3.4.1 NONROAD model sources

NONROAD model input files were prepared in both the fall of 2004 (Base F) and the spring of 2006 (Base G) based on the corresponding 2002 base year inventory input files available at the

time the forecasts were developed, with appropriate updates for the projection years. Generally, this means that the Base F 2002 base year input files (as updated through the fall of 2004) were used as the basis for Base F projection year input file development and Base G 2002 base year input files as updated through the spring of 2006 were used as the basis for Base G projection year input file development. Thus, all base year revisions are inherently incorporated into the associated projection year revisions. Other specific updates for the projection years for NONROAD model sources consist of:

1. Revise the emission inventory year in the model (as well as various output file naming commands) to be reflective of the projection year.
2. Revise the fuel sulfur content for gasoline and diesel powered equipment.
3. Implement a limited number of local control program charges (national control program changes are handled internally within the NONROAD model, so explicit input file changes are not required).

All equipment population growth and fleet turnover impacts are also handled internally within the NONROAD model, so that explicit changes input file changes are not required.

Base F Input File Changes:

To correctly account for diesel fuel sulfur content differences between the base and projection years, two sets of input and output files were prepared for each forecast year, one set for land-based equipment and one set for marine equipment. This two-step projection process was required for Base F, because diesel fuel sulfur contents varied between land-based and marine-based non-road equipment and the Draft NONROAD2004 used for Base F allowed only a single diesel fuel sulfur input. Thus, the model was executed separately for land-based and marine-based equipment for Base F, and the associated outputs subsequently combined. The specific diesel fuel sulfur contents modeled were as follows:

Diesel S (ppm)	2002	2009	2018
Land-Based	2500	348	11
Marine-Based	2500	408	56

As indicated, the Draft NONROAD2004 model was run with both sets of input files and the output file results were then combined to produce a single NONROAD output set.

To correctly account for the national reduction in gasoline sulfur content (a national control not explicitly handled by the NONROAD model), all NONROAD input files for both 2009 and 2018 were revised to reflect a gasoline fuel sulfur content of 30 ppmW.

Base G Input File Changes:

With the release of Final NONROAD2005 that was used for the Base G projection year inventory development, the NONROAD model is capable of handling separate diesel fuel sulfur inputs for land-based and marine-based non-road equipment in a single model execution. Therefore, the two step modeling process described above for Base F updates was no longer required. Instead, the differential diesel fuel sulfur values are assembled into a single NONROAD input file as follows:

Diesel S (ppm)	2002	2009	2018
Land-Based	2500	348	11
Marine-Based	2638	408	56

Additionally, revised gasoline vapor pressure data were provided by Georgia regulators for 20 counties[5] where reduced volatility requirements were established in 2003. Since this requirement began after the 2002 base year, the vapor pressure values in the base year input files for these counties are not correct for either the 2009 or 2018 forecast years. Therefore, to correctly forecast emissions in these counties, the forecast year gasoline vapor pressure inputs were revised to:

Gasoline RVP (psi)	2002	2009	2018
Spring	9.87	9.2	9.2
Summer	9.0	7.0	7.0
Fall	9.87	9.2	9.2
Winter	12.5	12.5	12.5

The summer vapor pressure was simply set equal to the 2003 control value, while the spring and fall vapor pressures were adjusted to reflect a single month of the reduced volatility limit. The winter volatility was assumed to be unaffected by the summertime control requirement.

2.3.4.1.1 Differences between 2009/2018

Other than diesel fuel sulfur content and the year of the projections, there are no differences in the methodology used to estimate emissions from NONROAD model sources. As indicated above, however the Base F 2009/2018 projections were developed using Draft NONROAD2004, while the Base G 2009/2018 projections were made using Final NONROAD2005.

[5] The specific counties are: Banks, Chattooga, Clarke, Floyd, Gordon, Heard, Jasper, Jones, Lamar, Lumpkin, Madison, Meriwether, Monroe, Morgan, Oconee, Pike, Polk, Putnam, Troup, and Upson.

2.3.4.2 Non-NONROAD model sources

Using the 2002 base year emissions inventory for aircraft, locomotives, and commercial marine vessels (CMV) prepared as described earlier in this document, corresponding emission projections for 2009 and 2018 were developed in both the fall of 2004 (Base F) and the spring of 2006 (Base G). This section describes the procedures employed in developing those inventories. The information presented is intended to build off of that presented in the section describing the 2002 Base F base year inventory. It should be recognized that for both the Base F and Base G inventories, the base year inventory used to develop the emission forecasts was the latest available at the time of forecast development. Generally, this means that the 2002 base year inventory as updated through the fall of 2004 was used as the basis for the Base F projection year inventory development, and the Base F 2002 base year inventory was used as the basis for Base G projection year inventory development. Thus, all base year revisions (as described earlier in this document) are inherently incorporated into the associated projection year revisions.

Base F Revisions:

Table 2.3-6 shows the 2002 base year emissions for each State in the VISTAS region for aircraft, locomotives and CMV (as they existed prior to Base F development).

Table 2.3-6 Pre-Base F 2002 Aircraft, Locomotive, and Non-Recreational Marine Emissions (annual tons, as of the fall of 2004)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	3,787	175	226	87	17	196
	FL	25,431	8,891	2,424	2,375	800	3,658
	GA	6,620	5,372	1,475	1,446	451	443
	KY	2,666	657	179	175	63	263
	MS	1,593	140	44	43	13	96
	NC	6,088	1,548	419	411	148	613
	SC	6,505	515	409	401	88	863
	TN	7,251	2,766	734	719	235	943
	VA	9,763	2,756	1,137	1,115	786	2,529
	WV	1,178	78	25	24	8	66
	Total	**70,882**	**22,899**	**7,072**	**6,797**	**2,607**	**9,670**
Commercial Marine (2280)	AL	1,196	9,218	917	844	3,337	737
	FL	5,888	44,817	1,936	1,781	6,683	1,409
	GA	1,038	7,875	334	307	1,173	246
	KY	6,607	50,267	2,246	2,066	9,608	1,569
	MS	5,688	43,233	1,903	1,751	7,719	1,351
	NC	599	4,547	193	178	690	142
	SC	1,067	8,100	343	316	1,205	253
	TN	3,624	27,555	1,217	1,120	4,974	860
	VA	972	2,775	334	307	359	483
	WV	1,528	11,586	487	448	525	362
	Total	**28,207**	**209,972**	**9,911**	**9,118**	**36,275**	**7,413**
Military Marine (2283)	VA	110	313	25	23	27	48
	Total	**110**	**313**	**25**	**23**	**27**	**48**
Locomotives (2285)	AL	3,490	26,339	592	533	1,446	1,354
	FL	1,006	9,969	247	222	605	404
	GA	2,654	26,733	664	598	1,622	1,059
	KY	2,166	21,811	542	488	1,321	867
	MS	2,302	23,267	578	520	1,429	899
	NC	1,638	16,502	410	369	1,001	654
	SC	1,160	11,690	291	261	710	462
	TN	2,626	25,627	633	570	1,439	1,041
	VA	1,186	11,882	1,529	1,375	3,641	492
	WV	1,311	13,224	329	296	808	517
	Total	**19,540**	**187,044**	**5,815**	**5,232**	**14,022**	**7,750**
Grand Total		**118,739**	**420,228**	**22,823**	**21,170**	**52,931**	**24,881**

Although some of the data utilized was updated, the methodology used to develop the Base F 2009 and 2018 emissions forecasts for aircraft, locomotives, and CMV is identical to that used earlier to develop preliminary 2018 Base 1 ("On the Books") and 2018 Base 2 ("On the Way") inventories. Briefly, the methodology relies on growth and control factors developed from inventories used in support of recent EPA rulemakings, and consists of the following steps:

(a) Begin with the 2002 base year emission estimates for aircraft, locomotive, and CMV as described above (at the State-county-SCC-pollutant level of detail).

(b) Detailed inventory data (both before and after controls) for these same emission sources for 1996, 2010, 2015, and 2020 were obtained from the EPA's Clean Air Interstate Rule (CAIR) Technical Support Document (which can be found at http://www.epa.gov/cair/pdfs/finaltech01.pdf). Using these data, combined growth and control factors for the period 2002-2009 and 2002-2018 were estimated using straight line interpolation between 1996 and 2010 (for 2009) and 2015 and 2020 (for 2018). This is done at the State-county-SCC-pollutant level of detail.

(c) The EPA growth and control data are matched against the 2002 VISTAS base year data using State-county-SCC-pollutant as the match key. Ideally, there would be a one-to-one match and the process would end at this point. Unfortunately, actual match results were not always ideal, so additional matching criteria were required. For subsequent reference, this initial (highest resolution) matching criterion is denoted as the "CAIR-Primary" criterion.

(d) A second matching criterion is applied that utilizes a similar, but higher-level SCC (lower resolution) matching approach. For example, SCC 2275020000 (commercial aircraft) in the 2002 base year inventory data would be matched with SCC 2275000000 (all aircraft) in the CAIR data. This criterion is applied to records in the 2002 base year emissions file that are not matched using the "CAIR-Primary" criterion, and is also performed at the State-county-SCC-pollutant level of detail. For subsequent reference, this is denoted as the "CAIR-Secondary" criterion. At the end of this process, a number of unmatched records remained, so a third level matching criterion was required.

(e) In the third matching step, the most frequently used SCC in the EPA CAIR files for each of the aircraft, locomotive, and commercial marine sectors was averaged at the State level to produce a "default" State and pollutant-specific growth and control factor for the sector. The resulting factor is used as a "default" growth factor for all unmatched county-SCC-pollutant level data in each State. In effect, State-specific growth data are applied to county level data for which an explicit match between the VISTAS 2002 base year data and EPA CAIR data could not be developed. The default growth and control

SCCs are 2275020000 (commercial aircraft) for the aircraft sector, 2280002000 (commercial marine diesel total) for the CMV sector, and 2285002000 (railroad equipment diesel total) for the locomotive sector. Matches made using this criterion are denoted as "CAIR-Tertiary" matches.

(f) According to EPA documentation, the CAIR baseline emissions include the impacts of the (then proposed) Tier 4 (T4) non-road diesel rulemaking, which implements a low sulfur fuel requirement that affects both future CMV and locomotive emissions. However, the impacts of this rule were originally intended to be excluded from the initial VISTAS 2018 forecast, which was to include only "on-the-books" controls. (The T4 rule was finalized subsequent to the development of the preliminary 2018 inventory in March of 2004.) Given its final status, T4 impacts were moved into the "on the books" inventory for non-road equipment. In addition, since there are no other proposed rules affecting the non-road sector between 2002 and 2018, there is no difference between the 2018 "on the books" and 2018 "on the way" inventories for the sector; so that only a single forecast inventory (for each evaluation year) was developed. Nevertheless, since the algorithms developed to produce the VISTAS forecasts were developed when there was a distinction between the "on the books" and "on the way" inventories, the distinct algorithms used to produce the two inventories have been maintained even though the conceptual distinctions have been lost. This approach was taken for two reasons. First, it allowed the previously developed algorithms to be utilized without change. Second, it allowed for separate treatment of the T4 emissions impact which was important as those impacts changed between the proposed and final T4 rules. Thus, previous EPA inventories that include the proposed T4 impacts would not be accurate. Therefore, the procedural discussion continues to reflect the distinctions between non-T4 and T4 emissions, as these distinctions continue to be intrinsically important to the forecasting process. Therefore, a second set of EPA CAIR files that excluded the Tier 4 diesel impacts was obtained and the same matching exercise described above in steps (b) through (e) was performed using these "No T4" files. It is important to note that the matching exercise described in steps (b) through (e) cannot simply be replaced because the "No T4" files obtained from the EPA include only those SCCs specifically affected by the T4 rule (i.e., diesel CMV and locomotives). So in effect, the matching exercise was augmented (rather than replaced) with an additional three criteria analogous to those described in steps (c) through (e), and these are denoted as the "No T4-Primary," "No T4-Secondary," and "No T4-Tertiary" criteria. Because they exclude the impacts of the proposed T4 rule, matches using the "No T4" criteria supersede matches made using the basic CAIR criteria (as described in steps (c) through (e) above).

(g) The CAIR matching criteria were overridden for any record for which States provided local growth data. Only North Carolina provided these forecasts, as that State has provided specific growth factors for airport emissions in four counties. Because the provided data were based on forecasted changes in landings and takeoffs at major North Carolina airports, the factors were applied only to commercial (SCC 2275020000) and air taxi (SCC 2275060000) emissions. Emissions forecasts for military and general aviation aircraft operations, as well as all aircraft operations in counties other than the four identified in the North Carolina growth factor submission, continued to utilize the growth factors developed according to steps (b) through (f) above. Table 2.3-7 presents the locally generated growth factors applied in North Carolina.

Table 2.3-7 Locally Generated Growth Factors for North Carolina

FIP	2009 Factor	2018 Factor
37067	0.71	0.84
37081	0.97	0.89
37119	1.15	1.01
37183	0.88	0.81

Note:

Growth factor = Year Emissions/2002 Emissions.
Under CAIR approach, 2009 = 1.16 to 1.17 for all 4 counties.
Under CAIR approach, 2018 = 1.36 to 1.37 for all 4 counties.

(h) Using this approach, each State-county-SCC-pollutant was assigned a combined growth and control factor using the EPA CAIR forecast or locally provided data. The 22,838 data records for aircraft, locomotives, and CMV in the 2002 revised base year emissions file were assigned growth factors in accordance with the following breakdown:

48 records matched State-provided growth factors,
4,179 records matched using the CAIR-Primary criterion,
240 records matched using the CAIR-Secondary criterion,
7,463 records matched using the CAIR-Tertiary criterion,
720 records matched using the No T4-Primary criterion,
3,858 records matched using the No T4-Secondary criterion, and
6,330 records matched using the No T4-Tertiary criterion.

(i) Finally, the impacts of the T4 rule as adopted were applied to the grown “non T4” emission estimates. The actual T4 emission standards do not affect aircraft, locomotive, or CMV directly, but associated diesel fuel sulfur requirements do affect locomotives and CMV. Lower fuel sulfur content affects both SO_2 and PM emissions. Expected fuel sulfur

contents were obtained for each evaluation year from the EPA technical support document for the final T4 rule (*Final Regulatory Analysis: Control of Emissions from Non-road Diesel Engines*, EPA420-R-04-007, May 2004). According to that document, the average diesel fuel sulfur content for locomotives and CMV is expected to be 408 ppmW in 2009 and 56 ppmW in 2018. These compare to expected non-T4 fuel sulfur levels of 2599 ppmW in 2009 and 2336 ppmW in 2018. Table 2.3-8 uses calculated emissions estimates for base and T4 control scenarios to estimate emission reduction impacts.

Table 2.3-8 Estimated Emission Reduction Impacts based on T-4 Rule

				2009	2018
CMV SO_2	=	Non-T4 SO_2	×	0.1569	0.0241
Locomotive SO_2	=	Non-T4 SO_2	×	0.1569	0.0241
CMV PM	=	Non-T4 PM	×	0.8962	0.8762
Locomotive PM	=	Non-T4 PM	×	0.8117	0.7734

However, since the diesel fuel sulfur content assumed for the 2002 VISTAS base year inventory, upon which both the 2009 and 2018 inventories were based, is 2500 ppmW, a small adjustment to the emission reduction multipliers calculated from the T4 rule is appropriate since they are measured relative to modestly different sulfur contents (2599 ppmW for 2009 and 2336 ppmW for 2018). Correcting for these modest differences produces the emission reduction impact estimates relative to forecasts based on the VISTAS 2002 inventory shown in Table 2.3-9.

Table 2.3-9 Estimated Emission Reduction Impacts Relative to VISTAS 2002 Base Year Values

				2009	2018
CMV SO_2	=	Non-T4 SO_2	×	0.1632	0.0225
Locomotive SO_2	=	Non-T4 SO_2	×	0.1632	0.0225
CMV PM	=	Non-T4 PM	×	0.9004	0.8685
Locomotive PM	=	Non-T4 PM	×	0.8187	0.7610

These factors were applied directly to the non-T4 emission forecasts to produce the final VISTAS 2009 and 2018 emissions inventories for aircraft, locomotive, and CMV.

The only exception is for Palm Beach County, Florida, where CMV emissions are reported as “all fuels” rather than separately by residual and diesel fuel components. To estimate T4 impacts in Palm Beach County, the ratio of diesel CMV emissions to total

CMV emissions in the remainder of Florida was calculated and the T4 impact estimates for Palm Beach County were adjusted to reflect that ratio. Table 2.3-10 shows the calculated diesel CMV ratios.

Table 2.3-10 Diesel CMV Adjustment Ratios for Palm Beach County, FL

GROWTH BASIS	SO_2	PM
2009 (1996, 2020 Growth Basis)	0.2410	0.7861
2009 (1996, 2010, 2015, and 2020 Growth Basis)	0.1279	0.7875
2018 (1996, 2020 Growth Basis)	0.2432	0.7925
2018 (1996, 2010, 2015, and 2020 Growth Basis)	0.2624	0.7918

The differences between the growth bases are discussed in detail below.

Combining these ratios with the T4 impact estimates for diesel engines, as presented above, yields the following impact adjustment factors for Palm Beach County:

Table 2.3-11 Overall Adjustment Factors for Palm Beach County, FL

GROWTH BASIS		
2009 SO_2 (19, 20 Growth Basis)	0.7894	[0.1632×0.2410+(1-0.2410)]
2009 SO_2 (96, 10, 15, and 20 Growth Basis)	0.8930	[0.1632×0.1279+(1-0.1279)]
2018 SO_2 (96, 20 Growth Basis)	0.7623	[0.0225×0.2432+(1-0.2432)]
2018 SO_2 (96, 10, 15, and 20 Growth Basis)	0.7436	[0.0225×0.2624+(1-0.2624)]
2009 PM (19, 20 Growth Basis)	0.9217	[0.9004×0.7861+(1-0.7861)]
2009 PM (96, 10, 15, and 20 Growth Basis)	0.9216	[0.9004×0.7875+(1-0.7875)]
2018 PM (96, 20 Growth Basis)	0.8958	[0.8685×0.7925+(1-0.7925)]
2018 PM (96, 10, 15, and 20 Growth Basis)	0.8959	[0.8685×0.7918+(1-0.7918)]

The differences between the growth bases are discussed in detail below.

Utilizing this approach, emission inventory forecasts for both 2009 and 2018 were developed. As indicated in step (b) above, basic growth factors were developed using EPA CAIR inventory data for 1996, 2010, 2015, and 2020. From these data, equivalent EPA CAIR inventories for 2002 and 2009 were developed through linear interpolation of the 1996 and 2010 inventories, while an equivalent CAIR inventory for 2018 was developed through linear interpolation of the 2015 and 2020 inventories. Growth factors for 2009 and 2018 were then estimated as the ratios of the CAIR 2009 and 2018 inventories to the CAIR 2002 inventory.

During the development of the preliminary 2018 VISTAS inventory in March 2004, this process yielded reasonable results and exhibited no particular systematic concerns. However, when the 2009 Base F inventory was developed, significant concerns related to SO_2 and PM were encountered. Essentially, what was revealed by the Base F 2009 forecast was a series of apparent

inconsistencies in the CAIR 2010 and 2015 emission inventories (as compared to the 1996 and 2020 CAIR inventories) that were masked during the construction of the "longer-term" 2018 inventory.

The apparent inconsistencies are best illustrated by looking at the actual data extracted from the CAIR inventory files. Note that although a limited example is being presented, the same general issue applies throughout the CAIR files. For FIP 01001 (Autauga County, Alabama) and SCC 2285002000 (Diesel Rail), the CAIR inventories indicate SO_2 emission estimates as shown in Table 2.3-12.

Table 2.3-12 SO_2 Emissions for Diesel Rail in Autauga County, AL from the CAIR Projections

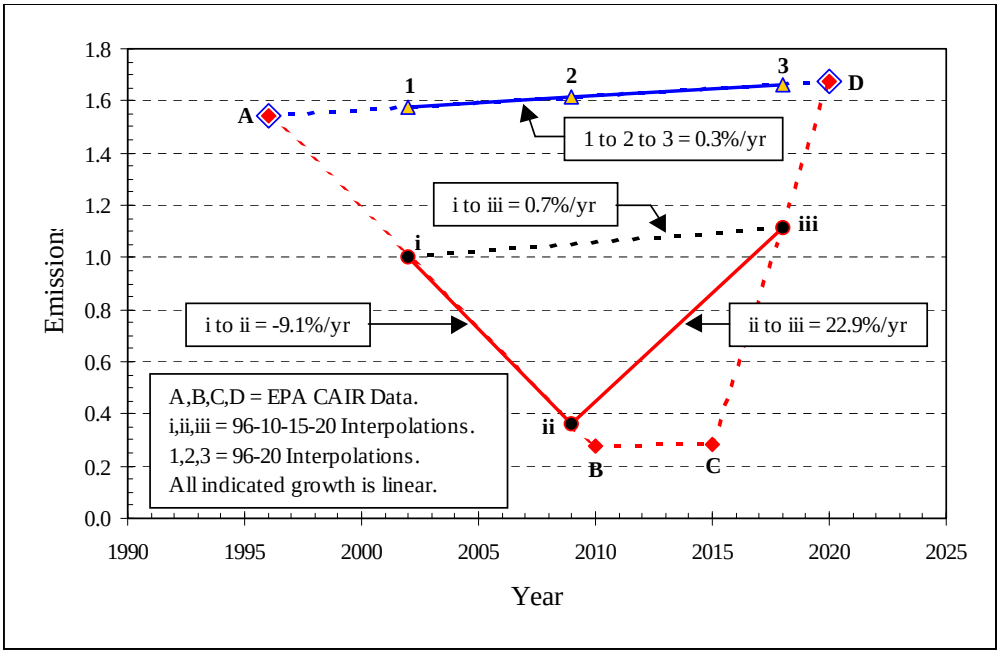
YEAR	TONS
1996:	15.3445
2010:	2.7271
2015:	2.8178
2020:	16.6232

Clearly, there is a major drop in emissions between 1996 and 2010, followed by a major increase in emissions between 2015 and 2020. Several observations regarding these changes are important. First, the CAIR data were reported to exclude the T4 rule, so that the drop in emissions should be related to something other than simply a change in diesel fuel sulfur content. Second, if the T4 rule impacts were "accidentally" included in the estimates, there should be a resultant 90 percent drop in diesel sulfur between 2010 and 2015; so such inclusion is unlikely. Third, the rate of growth between 2015 and 2020 (43 percent *per year* compound or 97 percent *per year* linear) is well beyond any reasonable expectations for rail service; and fuel sulfur content during this period is constant both with and without T4. In short, there appeared to be no rational explanation for the data, yet the same basic relations are observed for thousands of CAIR inventory records.

For the most part, the issue seems to be centered on SO_2 and PM records, which are those records primarily affected by the T4 rule. But, as noted above, there does not seem to be any pattern of consistency that would indicate that either inclusion or exclusion of T4 rule impacts is the underlying cause. Moreover, where they occur, the observed growth extremes generally affect both SO_2 and PM equally, while one would expect PM effects to be buffered if the T4 rule was the underlying cause, since changes in diesel fuel sulfur content will only affect a fraction of PM (i.e., sulfate), while directly reducing SO_2.

The data presented in Figure 2.3-1 illustrates what this meant to the VISTAS forecasting process. Figure 2.3-1 depicts the same data presented above for Autauga County, Alabama, but normalized so that the interpolated 2002 CAIR emissions estimate equals unity. The "raw" CAIR data is depicted by the markers labeled A, B, C, and D. Interpolated data for 2002 and 2009, based on 1996 and 2010 CAIR data, is depicted by the markers labeled "i" and "ii." Interpolated data for 2018, based on 2015 and 2020 CAIR data is depicted by the marker labeled "iii." The relationship between marker "iii" and marker "i" is exactly the relationship used to construct the preliminary (e.g., pre-Base F) 2018 VISTAS inventory (i.e., a linear growth rate equal to 0.7 percent per year). Thus, it is easy to see that although there is a major "dip and rise" between 2002 and 2018, it is essentially masked unless data for intervening years are examined. Since no intervening year was examined for the preliminary 2018 inventory, the "dip and rise" was not discovered. However, upon the development of the 2009 inventory forecast, the issue became obvious, as the marker labeled "ii" readily illustrates. In effect, the 2009 inventory reflected very low negative "growth rates" for some SCCs and pollutants relative to the 2002 inventory, while the 2018 inventory reflected very high and positive growth rates for those same SCCs and pollutants. In effect, the path between 2002 and 2018 that previously looked like the dotted line connecting markers "i" and "iii," now looks like the solid line connecting markers "i", "ii," and "iii." For reference purposes, this path is hereafter referred to as the 1996, 2010, 2015, and 2020 growth basis, since all interpolated data is based on CAIR data for those four years.

Figure 2.3-1 Impacts of the Apparent CAIR Inventory Discrepancy



In light of the apparent discrepancies inherent in the 1996, 2010, 2015, and 2020 growth basis data and the inconsistencies its use would impart into the 2009 and 2018 VISTAS inventories, a secondary forecasting method was developed. This second method relies on the apparent consistency between the 1996 and 2020 non-T4 CAIR inventories, interpolating equivalent 2002, 2009, and 2018 inventories solely from these two inventories. In effect, the CAIR inventories for 2010 and 2015 are ignored. In Figure 2.3-1, this secondary approach is depicted by the data points that lie along the lines connecting markers A and D. Markers A and D represent the 1996 and 2020 CAIR inventories, and the markers labeled 1, 2, and 3 represent the interpolated 2002, 2009, and 2018 CAIR equivalent inventories. The growth rate between 2009 and 2002 is then equal to the ratio of the 2009 and 2002 CAIR inventories, while that between 2018 and 2002 is equal to the ratio of the 2018 and 2002 CAIR inventories. For the example data, the resulting linear growth estimate is 0.3 percent per year. For reference purposes, this path is hereafter referred to as the 1996-2020 growth basis, since all interpolated data are based on CAIR data for only those two years.

It is perhaps worth noting that the only elements of Figure 2.3-1 that have any bearing on the VISTAS inventories are the growth rates. The absolute CAIR data are of importance only in determining those rates, as all VISTAS inventories were developed on the basis of the VISTAS 2002 base year inventory, not any of the CAIR inventories. So referring to Figure 2.3-1, the two growth options are summarized in Table 2.3-13.

Table 2.3-13 Growth Options based on CAIR Data

GROWTH BASIS	PERCENT PER YEAR
1996, 2010, 2015, 2020 Growth Basis:	-9.1% per year (linear) between 2002 and 2009
1996-2020 Growth Basis:	+0.3% per year (linear) between 2002 and 2009
1996, 2010, 2015, 2020 Growth Basis:	+22.9% per year (linear) between 2009 and 2018
1996-2020 Growth Basis:	+0.3% per year (linear) between 2009 and 2018
1996, 2010, 2015, 2020 Growth Basis:	+0.7% per year (linear) between 2002 and 2018
1996-2020 Growth Basis:	+0.3% per year (linear) between 2002 and 2018

Of course, these specific rates are applicable only to the example case (i.e., diesel rail SO_2 in Autauga County, Alabama), but there are thousands of additional CAIR records that are virtually identical from a growth viewpoint.

While forecast inventories for aircraft, locomotives, and CMV were developed for 2009 and 2018 using both growth methods, it was ultimately decided to utilize the 1996-2020 growth basis for Base F since it provided more reasonable growth rates for 2009. Tables 2.3-14 and 2.3-15 present a summary of each Base F inventory, while Tables 2.3-16 and 2.3-17 present the associated change in emissions for each Base F forecast inventory relative to the Base F 2002 base year VISTAS inventory. The larger reduction in CMV SO_2 emissions in 2009 and 2018

(relative to 2002) for Virginia and West Virginia is notable relative to the other VISTAS States, but this has been checked and is attributable to a high diesel contribution to total CMV SO_2 in the 2002 inventories for these two States.

Figures 2.3-2 through 2.3-13 graphically depict the relationships between the various Base F inventories and preliminary 2002 and 2018 projections prepared prior to Base F. There are two figures for each pollutant, the first of which presents a comparison of total VISTAS regional emission estimates for aircraft, locomotives, and CMV, and the second of which presents total VISTAS region emission estimates for locomotives only. This two figure approach is intended to provide a more robust illustration of the differences between the various inventories, as some of the differences are less distinct when viewed through overall aggregate emissions totals. All of the figures include the following emissions estimates:

- The 2002 Base F base year VISTAS emissions inventory (labeled as "2002"),
- The 2002 pre-Base F base year VISTAS emissions inventory (labeled as "2002 Prelim"),
- The Base F 2009 VISTAS emissions inventory developed using growth rates derived from 1996 and 2020 EPA CAIR data (labeled as "2009"),
- The Base F 2018 VISTAS emissions inventory developed using growth rates derived from 1996 and 2020 EPA CAIR data (labeled as "2018"), and
- The pre-Base F 2018 VISTAS emissions inventory estimates as developed using growth rates derived from 1996, 2010, 2015, and 2020 EPA CAIR data (labeled as "2018 Prelim").

All 12 figures generally illustrate a reduction in emissions estimates between the 2002 pre-Base F emission estimates published in February 2004 (the initial 2002 VISTAS inventory) and the 2002 Base F emission estimates. This reduction generally results from emission updates reflected in the State 2002 CERR submittals used to develop the Base F 2002 base year inventory, although the major differences in aggregate PM emission estimates are driven to a greater extent by modifications in the methodology used to estimate aircraft PM in the Base F 2002 base year inventory (as documented under the base year inventory section of this report).

Table 2.3-14 Base F 2009 Aircraft, Locomotive, and Non-Recreational Marine Emissions (annual tons) -- Based on Growth Using 1996 and 2020 EPA Inventories

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	4,178	202	278	102	19	217
	FL	29,258	10,316	2,812	2,756	928	4,235
	GA	7,635	6,233	1,712	1,678	523	512
	KY	3,075	762	207	203	73	304
	MS	1,765	162	51	50	16	108
	NC	6,551	1,601	436	427	153	644
	SC	7,372	559	446	437	98	975
	TN	8,020	3,096	824	807	268	1,050
	VA	10,994	3,094	1,239	1,214	907	2,892
	WV	1,312	91	28	28	9	74
	Total	**80,159**	**26,116**	**8,033**	**7,704**	**2,993**	**11,011**
Commercial Marine (2280)	AL	1,280	8,888	872	802	2,753	768
	FL	6,236	43,198	1,838	1,691	5,864	1,467
	GA	1,097	7,599	317	291	974	256
	KY	7,087	48,039	2,158	1,985	8,350	1,649
	MS	6,074	41,437	1,821	1,676	6,587	1,415
	NC	634	4,386	184	169	584	148
	SC	1,133	7,796	326	300	1,012	264
	TN	3,887	26,333	1,168	1,074	4,512	904
	VA	1,042	2,662	312	286	61	506
	WV	1,638	11,073	455	419	89	381
	Total	**30,109**	**201,412**	**9,450**	**8,693**	**30,786**	**7,759**
Military Marine (2283)	VA	118	299	23	21	5	50
	Total	**118**	**299**	**23**	**21**	**5**	**50**
Locomotives (2285)	AL	3,648	23,529	452	406	242	1,279
	FL	1,052	8,905	189	170	101	382
	GA	2,769	24,398	507	456	271	1,003
	KY	2,264	19,597	415	374	221	819
	MS	2,406	20,785	441	397	239	849
	NC	1,712	14,741	313	282	167	618
	SC	1,213	10,443	222	200	119	437
	TN	2,745	23,924	483	435	240	984
	VA	1,236	11,134	1,167	1,050	608	467
	WV	1,369	12,177	251	226	135	489
	Total	**20,412**	**169,635**	**4,440**	**3,995**	**2,343**	**7,328**
Grand Total		**130,798**	**397,462**	**21,946**	**20,413**	**36,126**	**26,148**

Table 2.3-15 Base F 2018 Aircraft, Locomotive, and Non-Recreational Marine Emissions (annual tons) -- Based on Growth Using 1996 and 2020 EPA Inventories

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	4,681	236	345	122	23	245
	FL	34,178	12,147	3,312	3,246	1,093	4,976
	GA	8,939	7,340	2,016	1,976	616	601
	KY	3,602	898	244	239	86	357
	MS	1,986	190	60	58	18	122
	NC	6,728	1,454	400	392	139	615
	SC	8,487	616	493	484	112	1,119
	TN	9,009	3,519	939	921	309	1,187
	VA	12,578	3,528	1,370	1,342	1,063	3,358
	WV	1,484	106	33	33	10	85
	Total	**91,670**	**30,035**	**9,213**	**8,814**	**3,468**	**12,666**
Commercial Marine (2280)	AL	1,388	8,464	880	809	2,715	809
	FL	6,684	41,117	1,853	1,705	6,248	1,543
	GA	1,174	7,246	319	293	976	269
	KY	7,703	45,174	2,199	2,023	8,383	1,752
	MS	6,571	39,129	1,850	1,702	6,556	1,498
	NC	679	4,179	185	170	596	155
	SC	1,217	7,406	329	303	1,027	278
	TN	4,225	24,763	1,190	1,095	4,808	960
	VA	1,133	2,517	314	289	9	537
	WV	1,781	10,412	459	422	13	404
	Total	**32,554**	**190,407**	**9,578**	**8,811**	**31,330**	**8,205**
Military Marine (2283)	VA	128	282	23	21	1	53
	Total	**128**	**282**	**23**	**21**	**1**	**53**
Locomotives (2285)	AL	3,850	19,917	381	343	34	1,183
	FL	1,110	7,538	159	143	14	353
	GA	2,917	21,395	427	385	38	932
	KY	2,389	16,751	352	317	31	757
	MS	2,540	17,594	372	335	34	785
	NC	1,807	12,478	264	237	24	571
	SC	1,280	8,840	187	168	17	404
	TN	2,897	21,735	407	367	34	910
	VA	1,300	10,173	983	885	86	436
	WV	1,444	10,831	212	190	19	453
	Total	**21,534**	**147,252**	**3,744**	**3,368**	**333**	**6,785**
Grand Total		**145,885**	**367,975**	**22,557**	**21,015**	**35,132**	**27,709**

Table 2.3-16 Change in Emissions between 2009 and 2002 Base F Inventories (Based on Growth Using 1996 and 2020 EPA Inventories)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	+10%	+15%	+23%	+18%	+16%	+11%
	FL	+15%	+16%	+16%	+16%	+16%	+16%
	GA	+15%	+16%	+16%	+16%	+16%	+16%
	KY	+15%	+16%	+16%	+16%	+16%	+16%
	MS	+11%	+16%	+15%	+15%	+16%	+12%
	NC	+8%	+3%	+4%	+4%	+3%	+5%
	SC	+13%	+9%	+9%	+9%	+12%	+13%
	TN	+11%	+12%	+12%	+12%	+14%	+11%
	VA	+13%	+12%	+9%	+9%	+15%	+14%
	WV	+11%	+16%	+15%	+15%	+16%	+12%
	Total	**+13%**	**+14%**	**+14%**	**+13%**	**+15%**	**+14%**
Commercial Marine (2280)	AL	+7%	-4%	-5%	-5%	-18%	+4%
	FL	+6%	-4%	-5%	-5%	-12%	+4%
	GA	+6%	-3%	-5%	-5%	-17%	+4%
	KY	+7%	-4%	-4%	-4%	-13%	+5%
	MS	+7%	-4%	-4%	-4%	-15%	+5%
	NC	+6%	-4%	-5%	-5%	-15%	+4%
	SC	+6%	-4%	-5%	-5%	-16%	+4%
	TN	+7%	-4%	-4%	-4%	-9%	+5%
	VA	+7%	-4%	-7%	-7%	-83%	+5%
	WV	+7%	-4%	-7%	-7%	-83%	+5%
	Total	**+7%**	**-4%**	**-5%**	**-5%**	**-15%**	**+5%**
Military Marine (2283)	VA	+7%	-4%	-7%	-7%	-83%	+5%
	Total	**+7%**	**-4%**	**-7%**	**-7%**	**-83%**	**+5%**
Locomotives (2285)	AL	+5%	-11%	-24%	-24%	-83%	-6%
	FL	+5%	-11%	-24%	-24%	-83%	-6%
	GA	+4%	-9%	-24%	-24%	-83%	-5%
	KY	+5%	-10%	-23%	-23%	-83%	-6%
	MS	+5%	-11%	-24%	-24%	-83%	-6%
	NC	+5%	-11%	-24%	-24%	-83%	-6%
	SC	+5%	-11%	-24%	-24%	-83%	-6%
	TN	+5%	-7%	-24%	-24%	-83%	-6%
	VA	+4%	-6%	-24%	-24%	-83%	-5%
	WV	+4%	-8%	-24%	-24%	-83%	-5%
	Total	**+4%**	**-9%**	**-24%**	**-24%**	**-83%**	**-5%**
Grand Total		**+10%**	**-5%**	**-4%**	**-4%**	**-32%**	**+5%**

Table 2.3-17 Change in Emissions between 2018 and 2002 Base F Inventories (Based on Growth Using 1996 and 2020 EPA Inventories)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	+24%	+35%	+53%	+41%	+36%	+25%
	FL	+34%	+37%	+37%	+37%	+37%	+36%
	GA	+35%	+37%	+37%	+37%	+37%	+36%
	KY	+35%	+37%	+37%	+37%	+37%	+36%
	MS	+25%	+36%	+35%	+35%	+36%	+27%
	NC	+10%	-6%	-5%	-5%	-6%	0%
	SC	+30%	+20%	+21%	+21%	+27%	+30%
	TN	+24%	+27%	+28%	+28%	+31%	+26%
	VA	+29%	+28%	+20%	+20%	+35%	+33%
	WV	+26%	+36%	+35%	+35%	+36%	+28%
	Total	**+29%**	**+31%**	**+30%**	**+30%**	**+33%**	**+31%**
Commercial Marine (2280)	AL	+16%	-8%	-4%	-4%	-19%	+10%
	FL	+14%	-8%	-4%	-4%	-7%	+9%
	GA	+13%	-8%	-5%	-5%	-17%	+9%
	KY	+17%	-10%	-2%	-2%	-13%	+12%
	MS	+16%	-9%	-3%	-3%	-15%	+11%
	NC	+13%	-8%	-4%	-4%	-14%	+9%
	SC	+14%	-9%	-4%	-4%	-15%	+10%
	TN	+17%	-10%	-2%	-2%	-3%	+12%
	VA	+17%	-9%	-6%	-6%	-98%	+11%
	WV	+17%	-10%	-6%	-6%	-98%	+12%
	Total	**+15%**	**-9%**	**-3%**	**-3%**	**-14%**	**+11%**
Military Marine (2283)	VA	+17%	-10%	-6%	-6%	-98%	+12%
	Total	**+17%**	**-10%**	**-6%**	**-6%**	**-98%**	**+12%**
Locomotives (2285)	AL	+10%	-24%	-36%	-36%	-98%	-13%
	FL	+10%	-24%	-36%	-36%	-98%	-13%
	GA	+10%	-20%	-36%	-36%	-98%	-12%
	KY	+10%	-23%	-35%	-35%	-98%	-13%
	MS	+10%	-24%	-36%	-36%	-98%	-13%
	NC	+10%	-24%	-36%	-36%	-98%	-13%
	SC	+10%	-24%	-36%	-36%	-98%	-13%
	TN	+10%	-15%	-36%	-36%	-98%	-13%
	VA	+10%	-14%	-36%	-36%	-98%	-11%
	WV	+10%	-18%	-36%	-36%	-98%	-12%
	Total	**+10%**	**-21%**	**-36%**	**-36%**	**-98%**	**-12%**
Grand Total		**+23%**	**-12%**	**-1%**	**-1%**	**-34%**	**+11%**

Figure 2.3-2 Total Aircraft, Locomotive, and CMV CO Emissions (Base F)

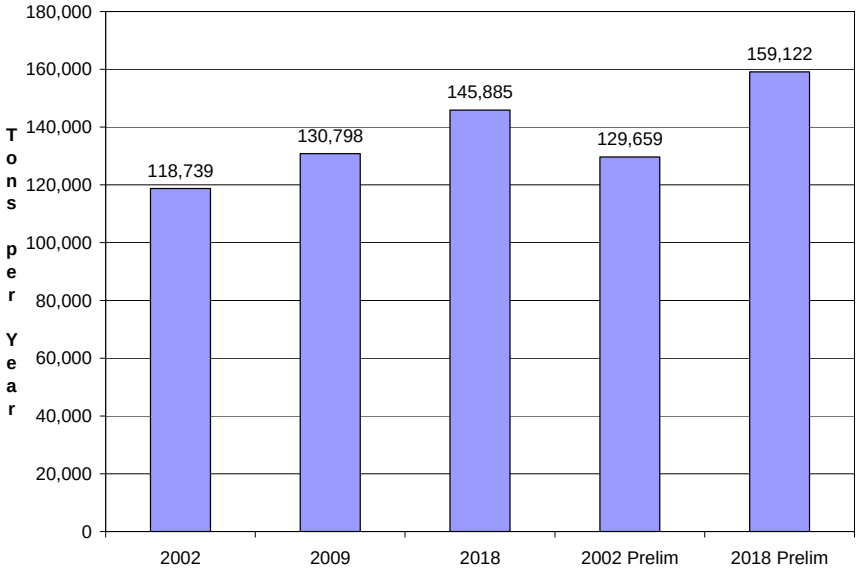


Figure 2.3-3 Locomotive CO Emissions (Base F)

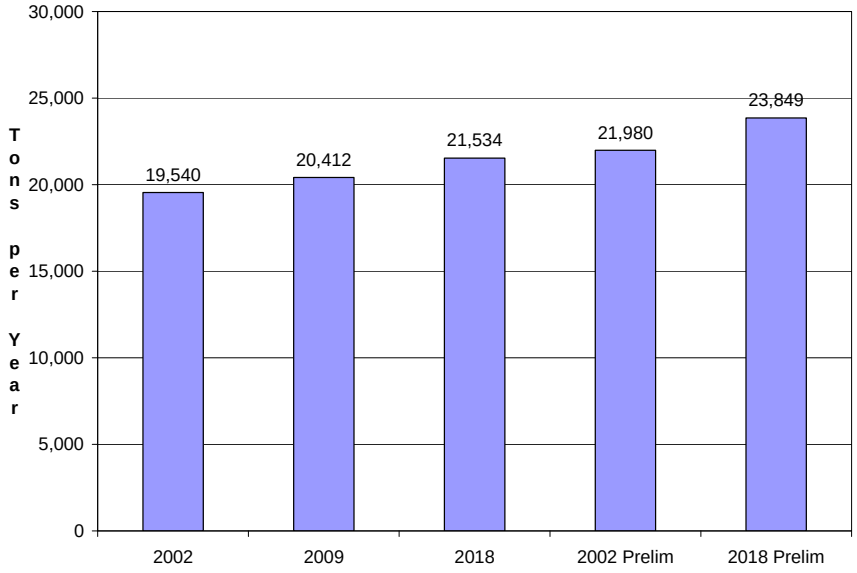


Figure 2.3-4 Total Aircraft, Locomotive, and CMV NO_x Emissions (Base F)

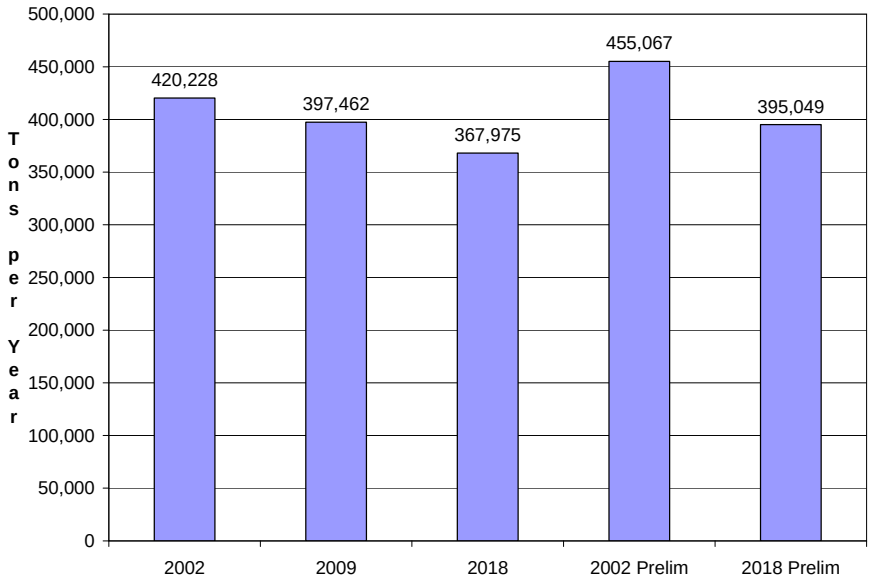


Figure 2.3-5 Locomotive NO_x Emissions (Base F)

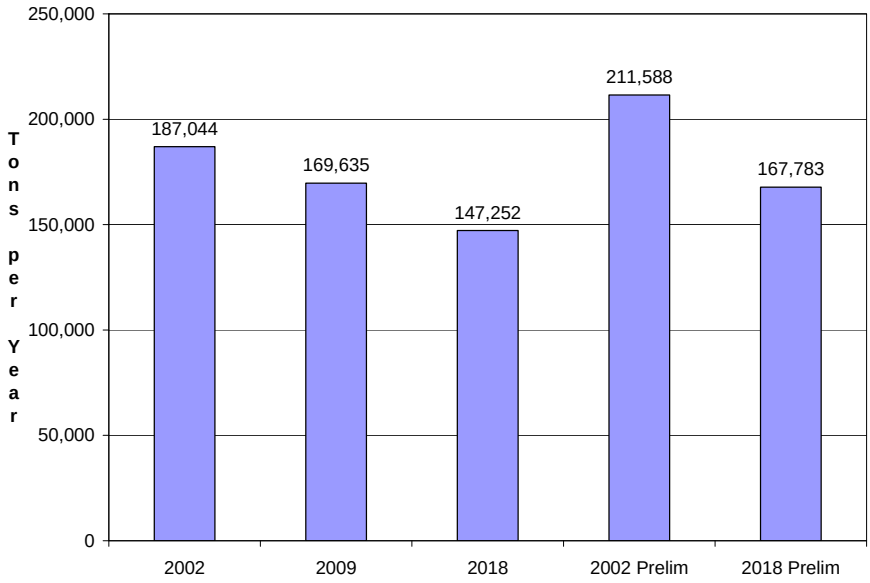


Figure 2.3-6 Total Aircraft, Locomotive, and CMV PM_{10} Emissions (Base F)

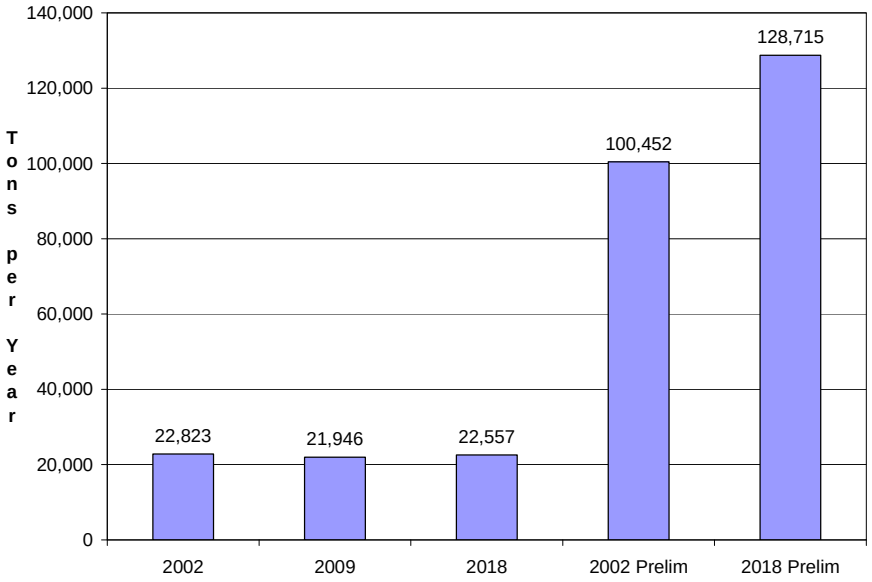


Figure 2.3-7 Locomotive PM_{10} Emissions (Base F)

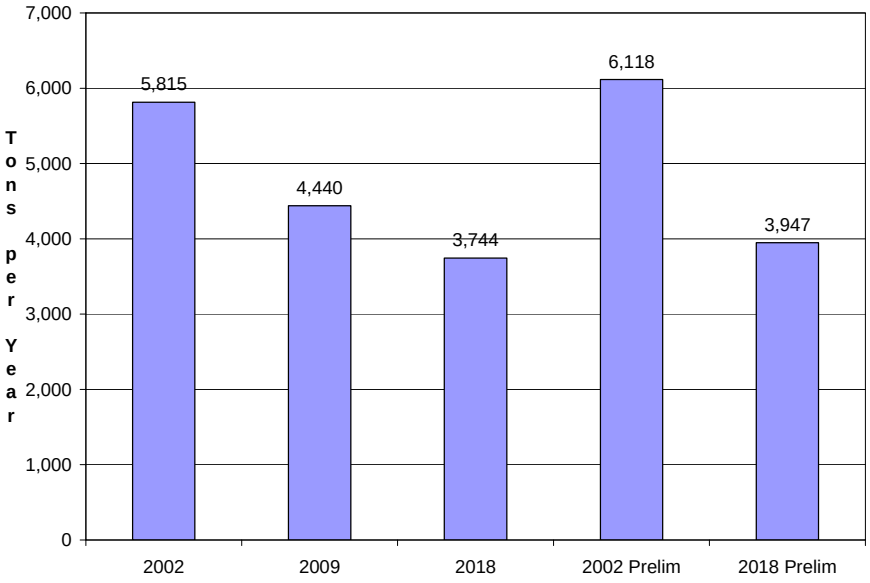


Figure 2.3-8 Total Aircraft, Locomotive, and CMV $PM_{2.5}$ Emissions (Base F)

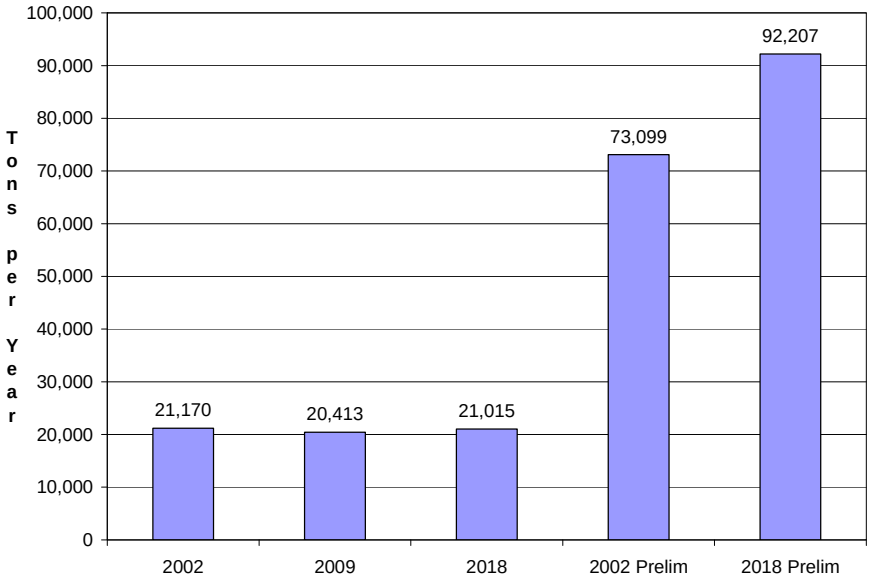


Figure 2.3-9 Locomotive $PM_{2.5}$ Emissions (Base F)

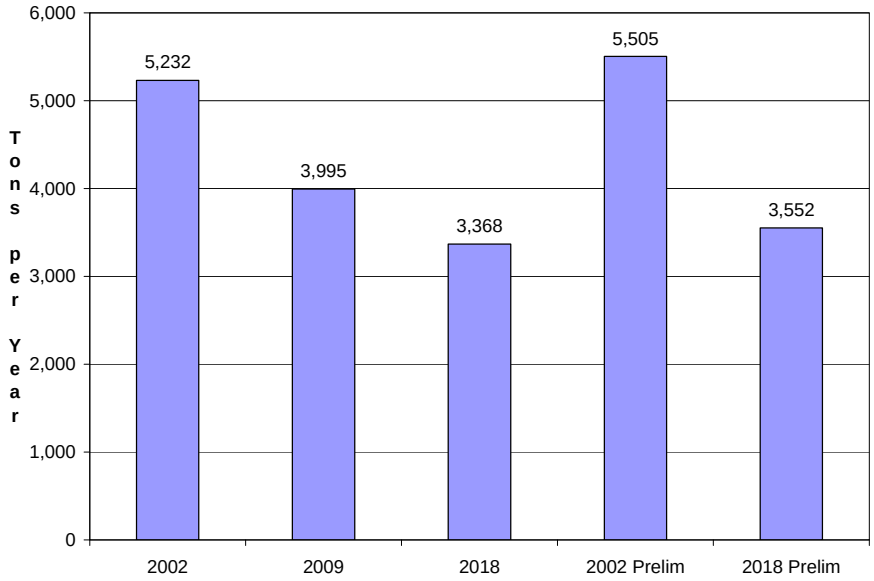


Figure 2.3-10 Total Aircraft, Locomotive, and CMV SO_2 Emissions (Base F)

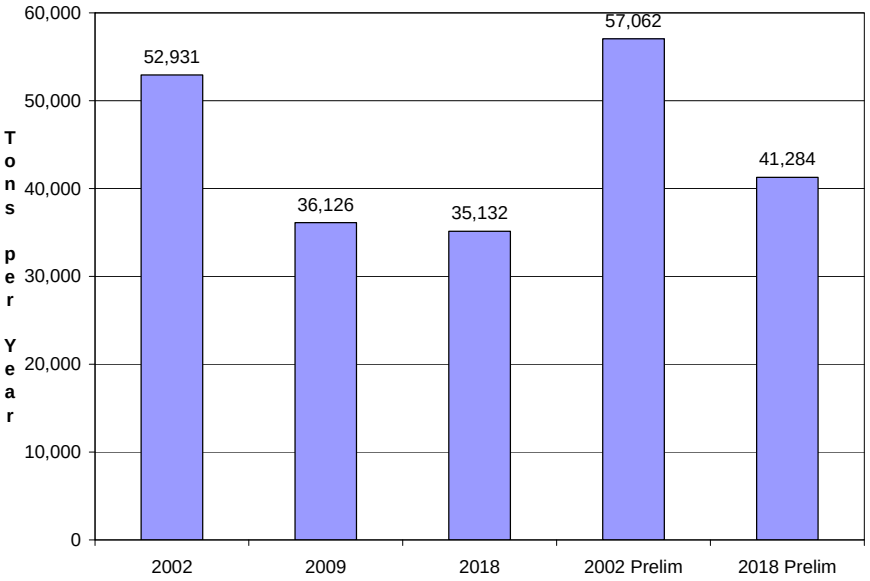


Figure 2.3-11 Locomotive SO_2 Emissions (Base F)

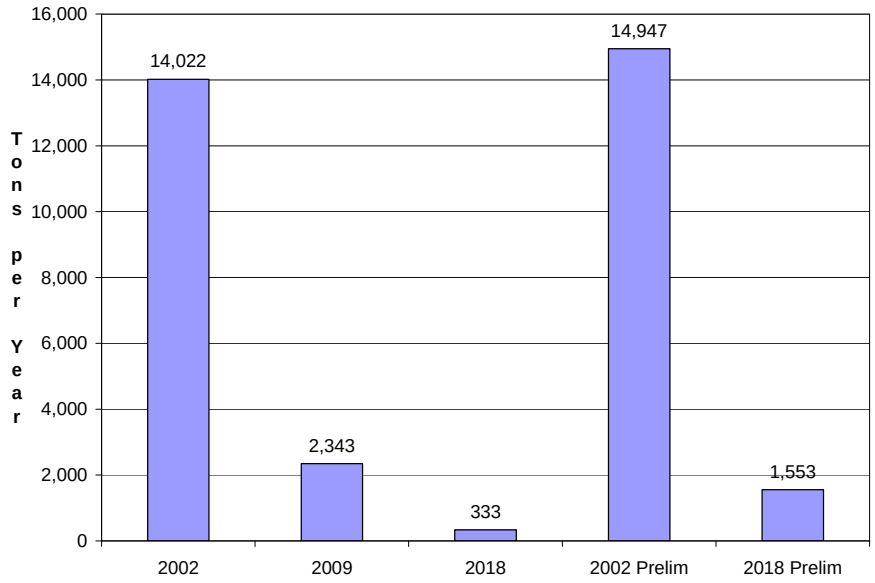


Figure 2.3-12 Total Aircraft, Locomotive, and CMV VOC Emissions (Base F)

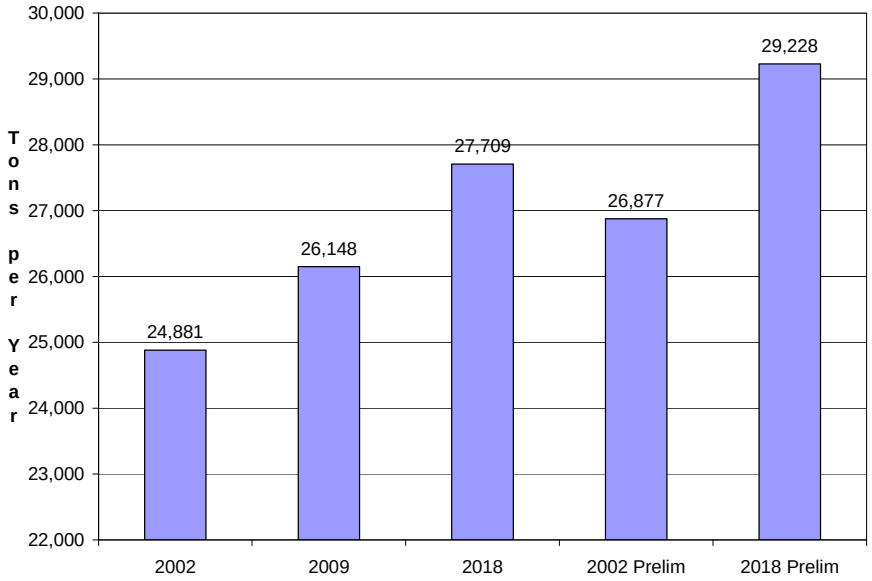
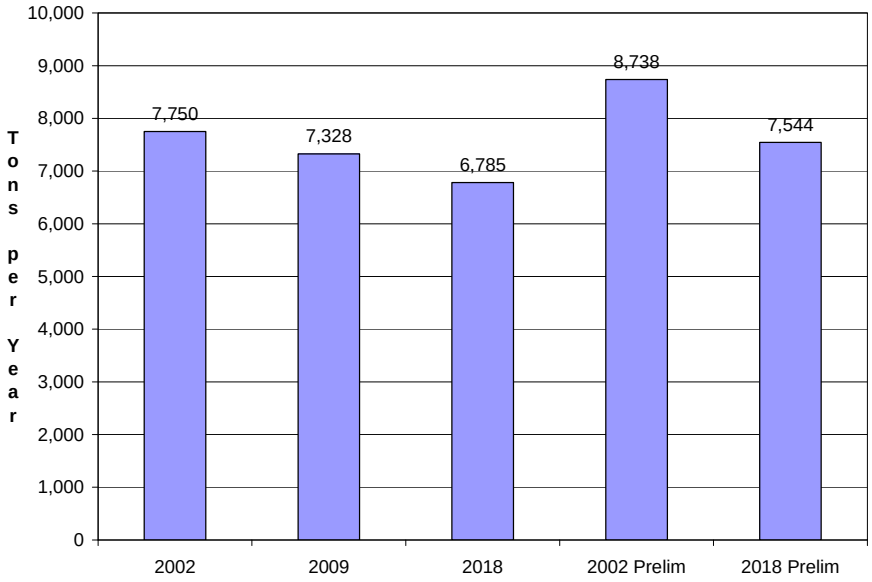


Figure 2.3-13 Locomotive VOC Emissions (Base F)



Base G Revisions:

Table 2.3-18 shows the Base G 2002 base year emissions for each State in the VISTAS region for aircraft, locomotives and CMV. Although some of these data are updated relative to those used as the basis of the Base F emissions forecasts, the methodology used to develop 2009 and 2018 emissions forecasts for aircraft, locomotives, and CMV for Base G is identical to that used for Base F (as documented above). The only exceptions are as follows:

(a) As indicated in the discussion of the Base F forecasts, the CAIR (growth rate) matching criteria were overridden for any record for which States provided local growth data. For Base F, only North Carolina provided such data. However, for Base G, Kentucky regulators provided growth data for aircraft emissions associated with Cincinnati/Northern Kentucky International Airport (located in Boone County, Kentucky). These data were applied to all pollutants and all aircraft types (i.e., military aircraft (SCC 2275001000), commercial aircraft (SCC 2275020000), general aviation aircraft (SCC 2275050000), and air taxi aircraft (SCC 2275060000)). Emissions forecasts for all aircraft operations in counties other than Boone continued to utilize the growth factors developed according to the CAIR matching criteria. Table 2.3-19 presents the locally generated growth factors applied in Kentucky. It should be recognized that although the locally provided growth factors presented in the table are significantly greater than those that would apply under the CAIR matching criteria, this is to be expected as local regulators noted a very significant decline in activity at the Cincinnati/Northern Kentucky International Airport in 2002 (relative to activity in preceding years). Moreover, this downward spike seems to have been alleviated since 2002, so that the provided growth factors represent not only “routine” growth expected between 2002 and the two forecast years, but growth required to offset the temporary decline observed in 2002.

Table 2.3-18 Base G 2002 Aircraft, Locomotive, and Non-Recreational Marine Emissions (annual tons)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	5,595	185	238	99	18	276
	FL	25,431	8,891	2,424	2,375	800	3,658
	GA	6,620	5,372	1,475	1,446	451	443
	KY	5,577	925	251	246	88	397
	MS	1,593	140	44	43	13	96
	NC	6,088	1,548	419	411	148	613
	SC	6,505	515	409	401	88	863
	TN	7,251	2,766	734	719	235	943
	VA	11,873	3,885	2,010	1,970	272	2,825
	WV	1,178	78	25	24	8	66
	Total	**77,712**	**24,305**	**8,029**	**7,734**	**2,121**	**10,179**
Commercial Marine (2280)	AL	1,196	9,218	917	844	3,337	737
	FL	5,888	44,817	1,936	1,781	6,683	1,409
	GA	1,038	7,875	334	307	1,173	246
	KY	6,607	50,267	2,246	2,066	9,608	1,569
	MS	5,688	43,233	1,903	1,751	7,719	1,351
	NC	599	4,547	193	178	690	142
	SC	1,067	8,100	343	316	1,205	253
	TN	3,624	27,555	1,217	1,120	4,974	860
	VA	972	2,775	334	307	359	483
	WV	1,528	11,586	487	448	525	362
	Total	**28,207**	**209,972**	**9,911**	**9,118**	**36,275**	**7,413**
Military Marine (2283)	VA	110	313	25	23	27	48
	Total	**110**	**313**	**25**	**23**	**27**	**48**
Locomotives (2285)	AL	3,518	26,623	592	533	1,446	1,365
	FL	1,006	9,969	247	222	605	404
	GA	2,654	26,733	664	598	1,622	1,059
	KY	2,166	21,811	542	488	1,321	867
	MS	2,302	23,267	578	520	1,429	899
	NC	1,638	16,502	410	369	1,001	654
	SC	1,160	11,690	291	261	710	462
	TN	2,626	25,627	633	570	1,439	1,041
	VA	1,186	11,882	1,529	1,375	3,641	492
	WV	1,311	13,224	329	296	808	517
	Total	**19,568**	**187,328**	**5,815**	**5,232**	**14,022**	**7,761**
Grand Total		**125,597**	**421,918**	**23,780**	**22,107**	**52,444**	**25,401**

Table 2.3-19 Locally Generated Growth Factors for Kentucky

FIP	2009 Factor	2018 Factor
21015	1.31	1.81

Note:

Growth factor = Year Emissions/2002 Emissions.
Under CAIR approach, 2009 = 0.99 to 1.17.
Under CAIR approach, 2018 = 0.97 to 1.40.

(b) Because of the additional emissions records added in Alabama, as discussed in the Base G 2002 base year inventory section of this report, the total number of emissions records in the Base G 2009 and 2018 forecasts increased to 23,042 (as compared to 22,838 for Base F). The 23,042 data records for aircraft, locomotives, and CMV were assigned growth factors in accordance with the following breakdown:

72	records matched State-provided growth factors,
4,287	records matched using the CAIR-Primary criterion,
240	records matched using the CAIR-Secondary criterion,
7,511	records matched using the CAIR-Tertiary criterion,
720	records matched using the No T4-Primary criterion,
3,858	records matched using the No T4-Secondary criterion, and
6,354	records matched using the No T4-Tertiary criterion.

Tables 2.3-20 and 2.3-21 present a summary of the resulting Base G 2009 and 2018 inventories, while Tables 2.3-22 and 2.3-23 present the associated change in emissions for each forecast inventory relative to the Base G 2002 base year VISTAS. As was the case with Base F, the larger reduction in CMV SO_2 emissions in 2009 and 2018 (relative to 2002) for Virginia and West Virginia is notable relative to the other VISTAS States, but is attributable to a high diesel contribution to total CMV SO_2 in the 2002 inventories for these two States.

Figures 2.3-14 through 2.3-25 graphically depict the relationships between the various inventories, as revised through Base G. There are two figures for each pollutant, the first of which presents a comparison of total VISTAS regional emission estimates for aircraft, locomotives, and CMV, and the second of which presents total VISTAS region emission estimates for locomotives only. This two figure approach is intended to provide a more robust illustration of the differences between the various inventories, as some of the differences are less distinct when viewed through overall aggregate emissions totals. All of the figures include the following emissions estimates:

- The Base G 2002 base year VISTAS emissions inventory (labeled as “2002”),
- The pre-Base F 2002 base year VISTAS emissions inventory (labeled as “2002 Prelim”),
- The Base G 2009 VISTAS emissions inventory developed using growth rates derived from 1996 and 2020 EPA CAIR data (labeled as “2009”),
- The Base G 2018 VISTAS emissions inventory developed using growth rates derived from 1996 and 2020 EPA CAIR data (labeled as “2018”), and
- The pre-Base F 2018 VISTAS emissions inventory estimates developed using growth rates derived from 1996, 2010, 2015, and 2020 EPA CAIR data (labeled as “2018 Prelim”).

All 12 figures generally illustrate a reduction in emissions estimates between the pre-Base F 2002 emission estimates published in February 2004 and the Base G 2002 base year emission estimates. This reduction generally results from emission updates reflected in the Base F State CERR submittals, although the major differences in aggregate PM emission estimates are driven to a greater extent by modifications in the methodology used to estimate aircraft PM in the Base F revisions to the 2002 Base F base year inventory (as documented under the base year inventory section of this report).

Table 2.3-20 Base G 2009 Aircraft, Locomotive, and Non-Recreational Marine Emissions (annual tons) -- Based on Growth Using 1996 and 2020 EPA Inventories

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	6,265	213	292	116	21	309
	FL	29,258	10,316	2,812	2,756	928	4,235
	GA	7,635	6,233	1,712	1,678	523	512
	KY	6,959	1,135	307	301	108	487
	MS	1,765	162	51	50	16	108
	NC	6,991	1,795	486	477	171	709
	SC	7,372	559	446	437	98	975
	TN	8,020	3,096	824	807	268	1,050
	VA	13,141	4,244	2,124	2,082	306	3,153
	WV	1,312	91	28	28	9	74
	Total	**88,716**	**27,844**	**9,083**	**8,732**	**2,447**	**11,612**
Commercial Marine (2280)	AL	1,280	8,888	872	802	2,753	768
	FL	6,236	43,198	1,838	1,691	5,864	1,467
	GA	1,097	7,599	317	291	974	256
	KY	7,087	48,039	2,158	1,985	8,350	1,649
	MS	6,074	41,437	1,821	1,676	6,587	1,415
	NC	634	4,386	184	169	584	148
	SC	1,133	7,796	326	300	1,012	264
	TN	3,887	26,333	1,168	1,074	4,512	904
	VA	1,042	2,662	312	286	61	506
	WV	1,638	11,073	455	419	89	381
	Total	**30,108**	**201,412**	**9,450**	**8,693**	**30,786**	**7,759**
Military Marine (2283)	VA	118	299	23	21	5	50
	Total	**118**	**299**	**23**	**21**	**5**	**50**
Locomotives (2285)	AL	3,677	23,783	452	406	242	1,289
	FL	1,052	8,905	189	170	101	382
	GA	2,769	24,398	507	456	271	1,003
	KY	2,264	19,597	415	374	221	819
	MS	2,406	20,785	441	397	239	849
	NC	1,690	14,662	311	279	165	613
	SC	1,213	10,443	222	200	119	437
	TN	2,745	23,924	483	435	240	984
	VA	1,236	11,134	1,167	1,050	608	467
	WV	1,369	12,177	251	226	135	489
	Total	**20,420**	**169,808**	**4,437**	**3,993**	**2,341**	**7,333**
Grand Total		**139,362**	**399,364**	**22,994**	**21,440**	**35,578**	**26,754**

Table 2.3-21 Base G 2018 Aircraft, Locomotive, and Non-Recreational Marine Emissions (annual tons) -- Based on Growth Using 1996 and 2020 EPA Inventories

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	7,126	249	361	139	24	352
	FL	34,178	12,147	3,312	3,246	1,093	4,976
	GA	8,939	7,340	2,016	1,976	616	601
	KY	9,078	1,446	391	383	138	623
	MS	1,986	190	60	58	18	122
	NC	8,150	2,114	572	561	202	831
	SC	8,487	616	493	484	112	1,119
	TN	9,009	3,519	939	921	309	1,187
	VA	14,770	4,706	2,271	2,226	349	3,574
	WV	1,484	106	33	33	10	85
	Total	**103,206**	**32,435**	**10,450**	**10,027**	**2,871**	**13,472**
Commercial Marine (2280)	AL	1,388	8,464	880	809	2,715	809
	FL	6,684	41,117	1,853	1,705	6,248	1,543
	GA	1,174	7,246	319	293	976	269
	KY	7,703	45,174	2,199	2,023	8,383	1,752
	MS	6,571	39,129	1,850	1,702	6,556	1,498
	NC	678	4,179	185	170	596	155
	SC	1,217	7,406	329	303	1,027	278
	TN	4,225	24,763	1,190	1,095	4,808	960
	VA	1,133	2,517	314	289	9	537
	WV	1,781	10,412	459	422	13	404
	Total	**32,554**	**190,407**	**9,578**	**8,811**	**31,330**	**8,205**
Military Marine (2283)	VA	128	282	23	21	1	53
	Total	**128**	**282**	**23**	**21**	**1**	**53**
Locomotives (2285)	AL	3,881	20,131	381	343	34	1,192
	FL	1,110	7,538	159	143	14	353
	GA	2,917	21,395	427	385	38	932
	KY	2,389	16,751	352	317	31	757
	MS	2,540	17,594	372	335	34	785
	NC	1,782	12,539	263	237	23	570
	SC	1,280	8,840	187	168	17	404
	TN	2,897	21,735	407	367	34	910
	VA	1,300	10,173	983	885	86	436
	WV	1,444	10,831	212	190	19	453
	Total	**21,539**	**147,527**	**3,743**	**3,368**	**332**	**6,792**
Grand Total		**157,427**	**370,651**	**23,794**	**22,227**	**34,534**	**28,522**

Table 2.3-22 Change in Emissions between 2009 Base G and 2002 Base F Inventories (Based on Growth Using 1996 and 2020 EPA Inventories)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	+12%	+15%	+23%	+18%	+16%	+12%
	FL	+15%	+16%	+16%	+16%	+16%	+16%
	GA	+15%	+16%	+16%	+16%	+16%	+16%
	KY	+25%	+23%	+23%	+23%	+23%	+23%
	MS	+11%	+16%	+15%	+15%	+16%	+12%
	NC	+15%	+16%	+16%	+16%	+16%	+16%
	SC	+13%	+9%	+9%	+9%	+12%	+13%
	TN	+11%	+12%	+12%	+12%	+14%	+11%
	VA	+11%	+9%	+6%	+6%	+12%	+12%
	WV	+11%	+16%	+15%	+15%	+16%	+12%
	Total	**+14%**	**+15%**	**+13%**	**+13%**	**+15%**	**+14%**
Commercial Marine (2280)	AL	+7%	-4%	-5%	-5%	-18%	+4%
	FL	+6%	-4%	-5%	-5%	-12%	+4%
	GA	+6%	-3%	-5%	-5%	-17%	+4%
	KY	+7%	-4%	-4%	-4%	-13%	+5%
	MS	+7%	-4%	-4%	-4%	-15%	+5%
	NC	+6%	-4%	-5%	-5%	-15%	+4%
	SC	+6%	-4%	-5%	-5%	-16%	+4%
	TN	+7%	-4%	-4%	-4%	-9%	+5%
	VA	+7%	-4%	-7%	-7%	-83%	+5%
	WV	+7%	-4%	-7%	-7%	-83%	+5%
	Total	**+7%**	**-4%**	**-5%**	**-5%**	**-15%**	**+5%**
Military Marine (2283)	VA	+7%	-4%	-7%	-7%	-83%	+5%
	Total	**+7%**	**-4%**	**-7%**	**-7%**	**-83%**	**+5%**
Locomotives (2285)	AL	+5%	-11%	-24%	-24%	-83%	-6%
	FL	+5%	-11%	-24%	-24%	-83%	-6%
	GA	+4%	-9%	-24%	-24%	-83%	-5%
	KY	+5%	-10%	-23%	-23%	-83%	-6%
	MS	+5%	-11%	-24%	-24%	-83%	-6%
	NC	+3%	-11%	-24%	-24%	-83%	-6%
	SC	+5%	-11%	-24%	-24%	-83%	-6%
	TN	+5%	-7%	-24%	-24%	-83%	-6%
	VA	+4%	-6%	-24%	-24%	-83%	-5%
	WV	+4%	-8%	-24%	-24%	-83%	-5%
	Total	**+4%**	**-9%**	**-24%**	**-24%**	**-83%**	**-6%**
Grand Total		**+11%**	**-5%**	**-3%**	**-3%**	**-32%**	**+5%**

Table 2.3-23 Change in Emissions between 2018 Base G and 2002 Base F Inventories (Based on Growth Using 1996 and 2020 EPA Inventories)

Source	State	CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
Aircraft (2275)	AL	+27%	+35%	+52%	+41%	+36%	+28%
	FL	+34%	+37%	+37%	+37%	+37%	+36%
	GA	+35%	+37%	+37%	+37%	+37%	+36%
	KY	+63%	+56%	+56%	+56%	+56%	+57%
	MS	+25%	+36%	+35%	+35%	+36%	+27%
	NC	+34%	+37%	+36%	+36%	+37%	+36%
	SC	+30%	+20%	+21%	+21%	+27%	+30%
	TN	+24%	+27%	+28%	+28%	+31%	+26%
	VA	+24%	+21%	+13%	+13%	+28%	+27%
	WV	+26%	+36%	+35%	+35%	+36%	+28%
	Total	**+33%**	**+33%**	**+30%**	**+30%**	**+35%**	**+32%**
Commercial Marine (2280)	AL	+16%	-8%	-4%	-4%	-19%	+10%
	FL	+14%	-8%	-4%	-4%	-7%	+9%
	GA	+13%	-8%	-5%	-5%	-17%	+9%
	KY	+17%	-10%	-2%	-2%	-13%	+12%
	MS	+16%	-9%	-3%	-3%	-15%	+11%
	NC	+13%	-8%	-4%	-4%	-14%	+9%
	SC	+14%	-9%	-4%	-4%	-15%	+10%
	TN	+17%	-10%	-2%	-2%	-3%	+12%
	VA	+17%	-9%	-6%	-6%	-98%	+11%
	WV	+17%	-10%	-6%	-6%	-98%	+12%
	Total	**+15%**	**-9%**	**-3%**	**-3%**	**-14%**	**+11%**
Military Marine (2283)	VA	+17%	-10%	-6%	-6%	-98%	+12%
	Total	**+17%**	**-10%**	**-6%**	**-6%**	**-98%**	**+12%**
Locomotives (2285)	AL	+10%	-24%	-36%	-36%	-98%	-13%
	FL	+10%	-24%	-36%	-36%	-98%	-13%
	GA	+10%	-20%	-36%	-36%	-98%	-12%
	KY	+10%	-23%	-35%	-35%	-98%	-13%
	MS	+10%	-24%	-36%	-36%	-98%	-13%
	NC	+9%	-24%	-36%	-36%	-98%	-13%
	SC	+10%	-24%	-36%	-36%	-98%	-13%
	TN	+10%	-15%	-36%	-36%	-98%	-13%
	VA	+10%	-14%	-36%	-36%	-98%	-11%
	WV	+10%	-18%	-36%	-36%	-98%	-12%
	Total	**+10%**	**-21%**	**-36%**	**-36%**	**-98%**	**-12%**
Grand Total		**+25%**	**-12%**	**+0%**	**+1%**	**-34%**	**+12%**

Figure 2.3-14 Total Aircraft, Locomotive, and CMV CO Emissions (Base G)

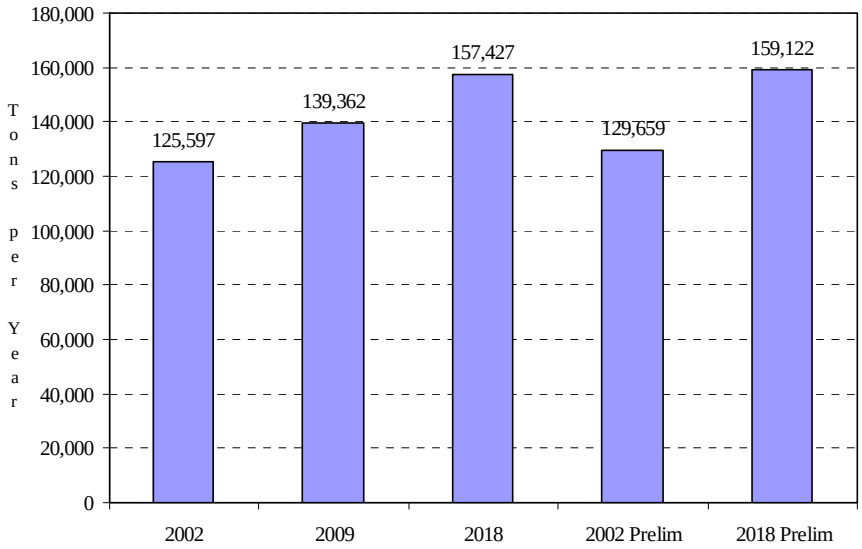


Figure 2.3-15 Locomotive CO Emissions (Base G)

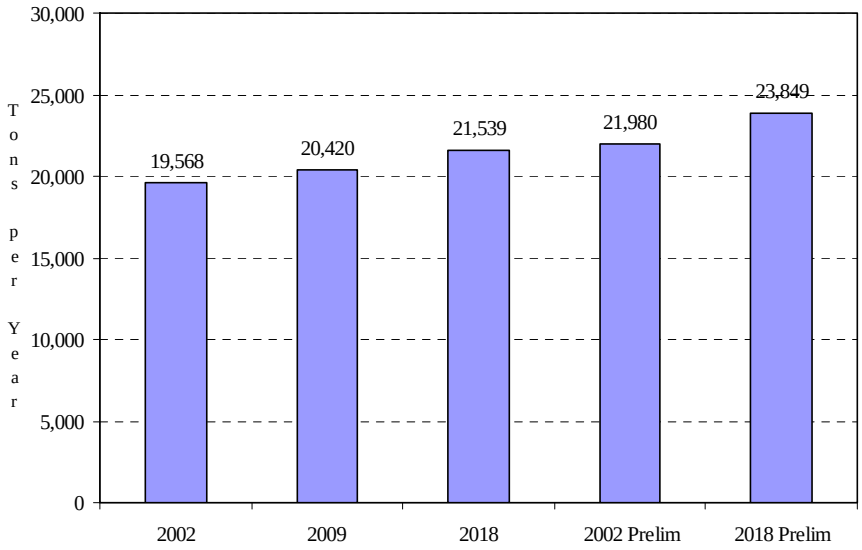


Figure 2.3-16 Total Aircraft, Locomotive, and CMV NO_x Emissions (Base G)

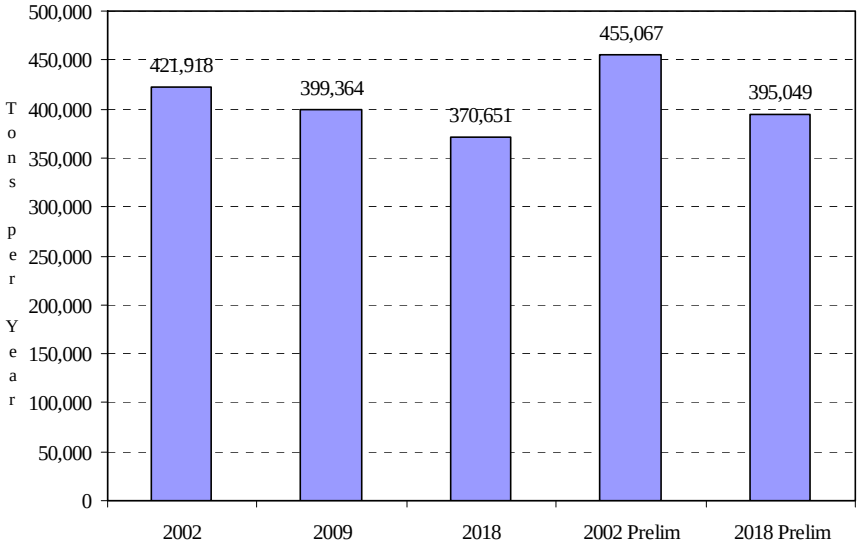


Figure 2.3-17 Locomotive NO_x Emissions (Base G)

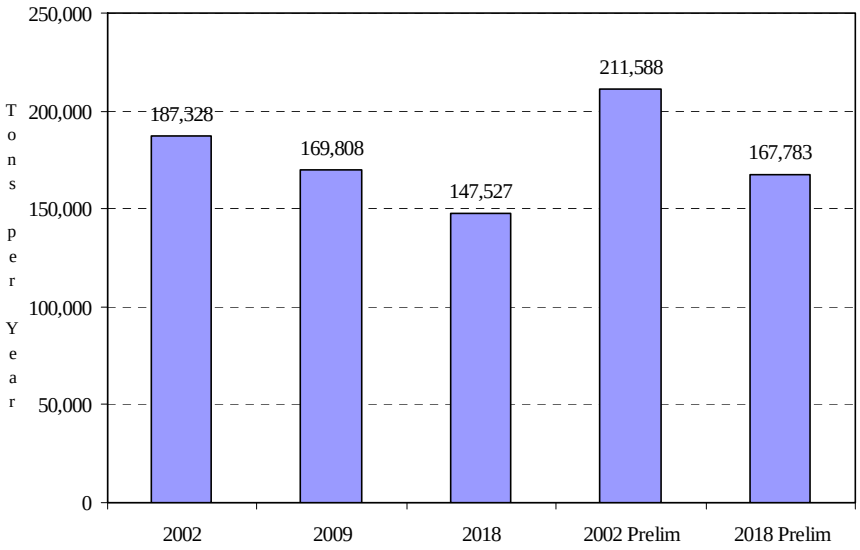


Figure 2.3-18 Total Aircraft, Locomotive, and CMV PM_{10} Emissions (Base G)

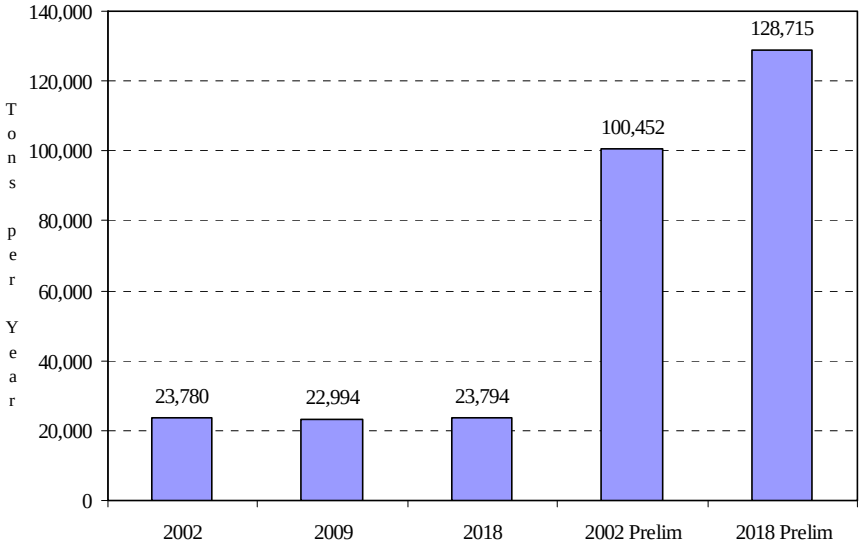


Figure 2.3-19 Locomotive PM_{10} Emissions (Base G)

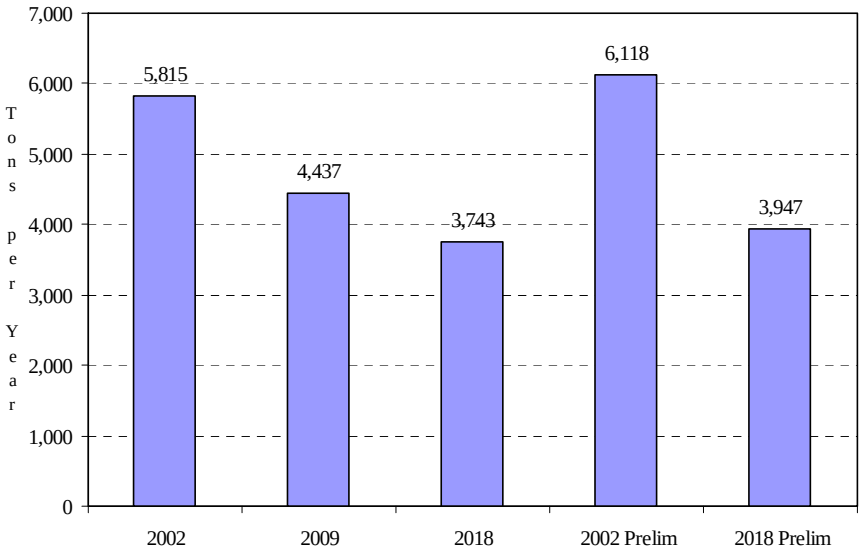


Figure 2.3-20 Total Aircraft, Locomotive, and CMV $PM_{2.5}$ Emissions (Base G)

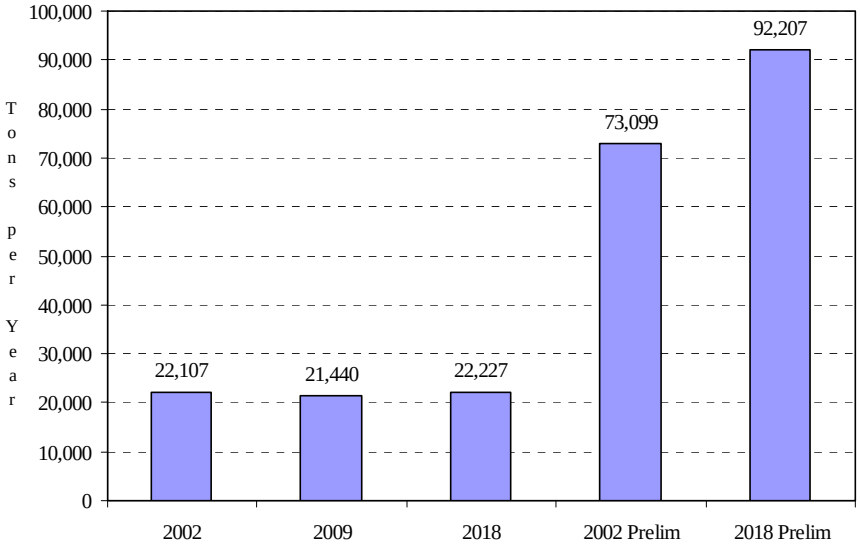


Figure 2.3-21 Locomotive $PM_{2.5}$ Emissions (Base G)

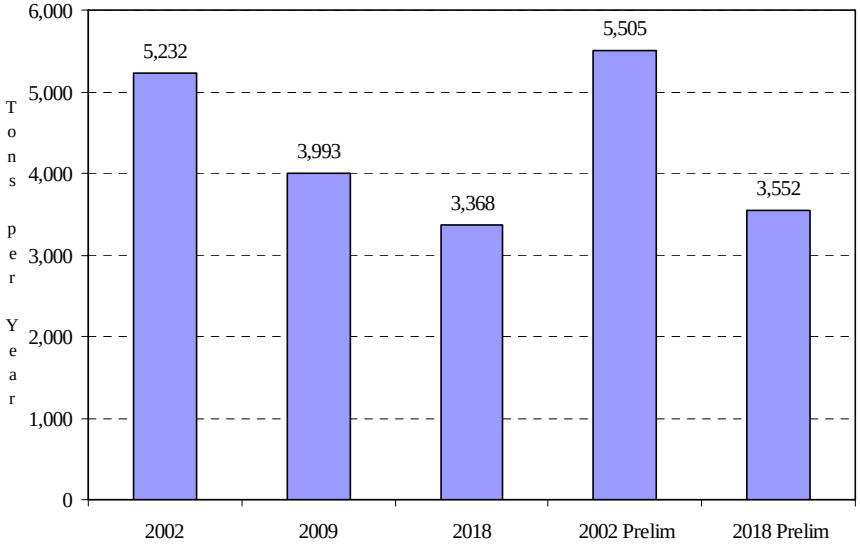


Figure 2.3-22 Total Aircraft, Locomotive, and CMV SO_2 Emissions (Base G)

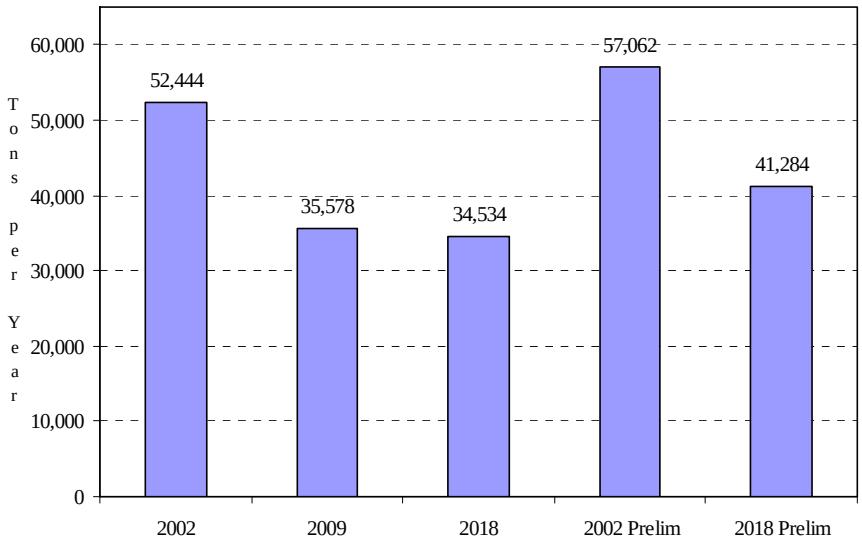


Figure 2.3-23 Locomotive SO_2 Emissions (Base G)

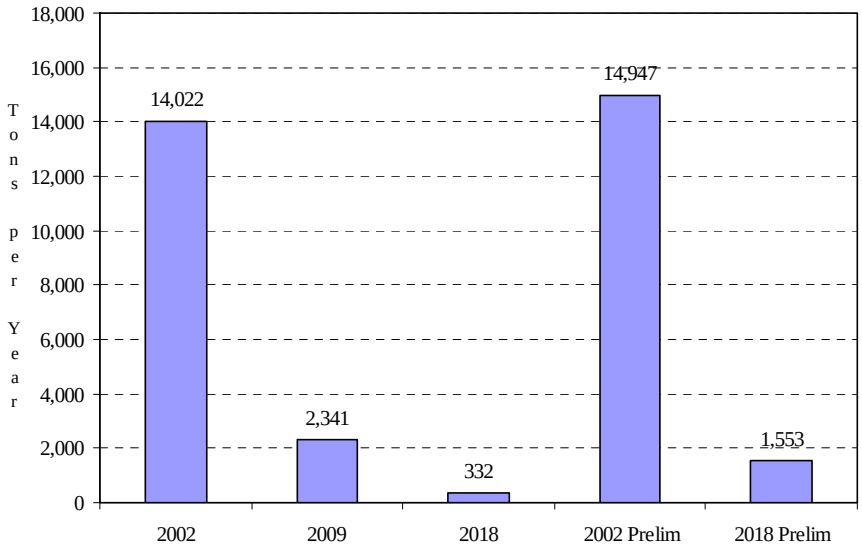


Figure 2.3-24 Total Aircraft, Locomotive, and CMV VOC Emissions (Base G)

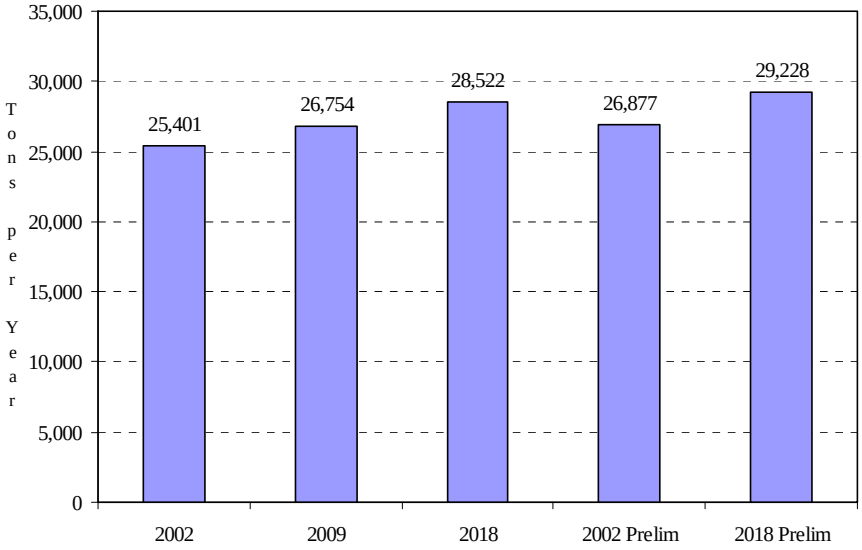
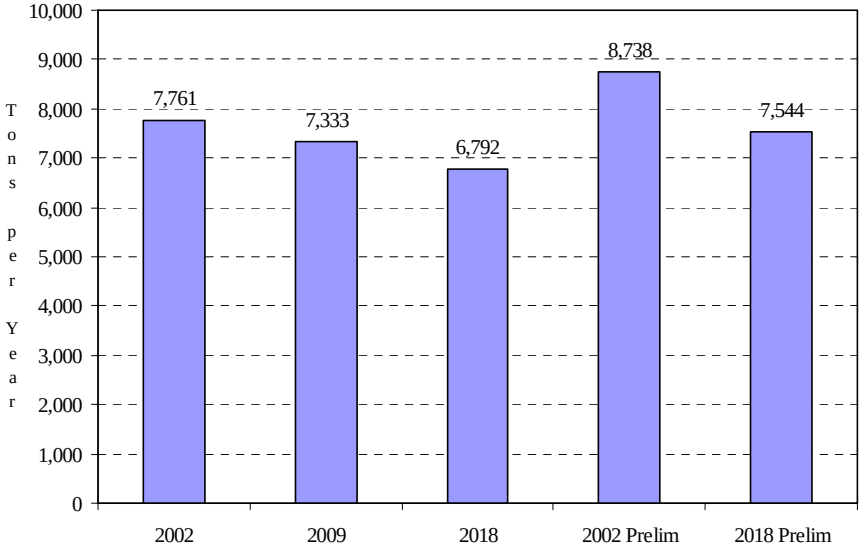


Figure 2.3-25 Locomotive VOC Emissions (Base G)



2.3.4.3 Emissions from NONROAD Model Sources in Illinois, Indiana, and Ohio

Base G projection inventories for 2009 and 2018 for NONROAD model sources in the states of Illinois, Indiana, and Ohio were produced using a methodology identical to that employed to develop a Base G 2002 base year inventory for the same states (as documented earlier in this report). This method consists of the extraction of a complete set of county-level input data applicable to each of the three states (in each of the two projection years) from the latest version of the EPA's NMIM model. This includes appropriate consideration of all non-default NMIM input files generated by the Midwest Regional Planning Organization as documented earlier in the discussion of the Base G 2002 base year inventory. These input data were then assembled into appropriate input files for the Final NONROAD2005 model and emission estimates were produced using the same procedure employed for the VISTAS region.

Changes noted between the base year (2002) and forecast year (2009 and 2018) input data extracted from NMIM include differences in gasoline vapor pressure, gasoline sulfur content, and diesel sulfur content in most counties. All temperature data (minimum, maximum, and average daily temperatures) was constant across years.

As described in the discussion of the Base G 2002 base year inventory, counties in the three states were grouped for modeling purposes using a temperature aggregation scheme that allowed for county-specific temperature variations of no more that 2 ºF from group average temperatures (for all temperature inputs). The same grouping scheme was applied to projection year modeling, so that Illinois emissions were modeled using 12 county groups, Indiana emissions were modeled using 9 county groups, and Ohio emissions were modeled using 10 county groups. Thus, 31 iterations of NONROAD2002 were required per season per projection year, as compared to the 53 iterations per season per projection year required for the VISTAS region.

As was also described in the discussion of the Base G 2002 base year inventory, several non-default equipment population, growth, activity, seasonal distribution, and county allocation files are assigned by NMIM model inputs for these counties. As was the case for the base year inventory development, these same non-default assignments were retained for both projection inventories.

2.3.4.4 Differences between 2009/2018

Methodologically, there was no difference in the way that 2009 and 2018 emissions were calculated for non-road mobile sources. The actual value of the growth factors were different for each type of mobile source considered, but the calculation methods were identical.

2.3.5 Quality Assurance steps

Throughout the inventory development process, quality assurance steps were performed to ensure that no double counting of emissions occurred, to ensure that a full and complete inventory was developed for VISTAS, and to make sure that projection calculations were working correctly. Quality assurance was an important component to the inventory development process and MACTEC performed the following QA steps on mobile source components of the 2009 and revised 2018 projection inventories:

1. All final files (NONROAD only) were run through EPA's Format and Content checking software. Input data files for MOBILE and VMT growth estimates were reviewed by the corresponding SIWG and by the VISTAS Emission Inventory Technical Advisor.

2. SCC level emission summaries were prepared and evaluated to ensure that emissions were consistent and that there were no missing sources (NONROAD only).

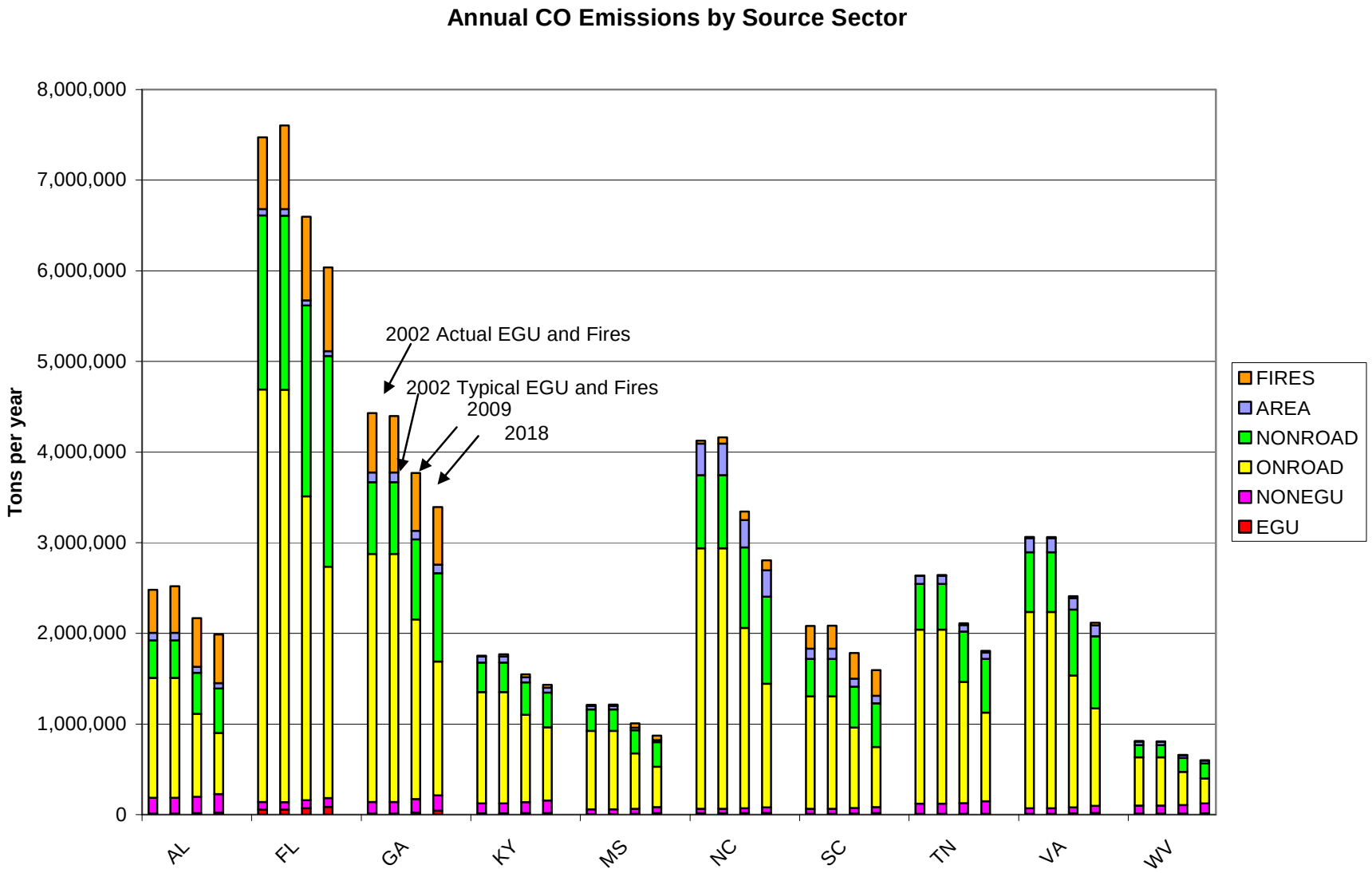
3. Tier comparisons (by pollutant) were developed between the 2002 base year inventory and the 2009 and 2018 projection inventories (NONROAD only). Total VISTAS level summaries by pollutant were developed for these sources to compare Base F and Base G emission levels.

4. Data product summaries were provided to both the VISTAS Emission Inventory Technical Advisor and to the SIWG representatives for review and comment. Changes based on these comments were implemented in the files.

5. Version numbering was used for all inventory files developed. The version numbering process used a decimal system to track major and minor changes. For example, a major change would result in a version going from 1.0 to 2.0. A minor change would cause a version number to go from 1.0 to 1.1. Minor changes resulting from largely editorial changes would result in a change from 1.00 to 1.01.

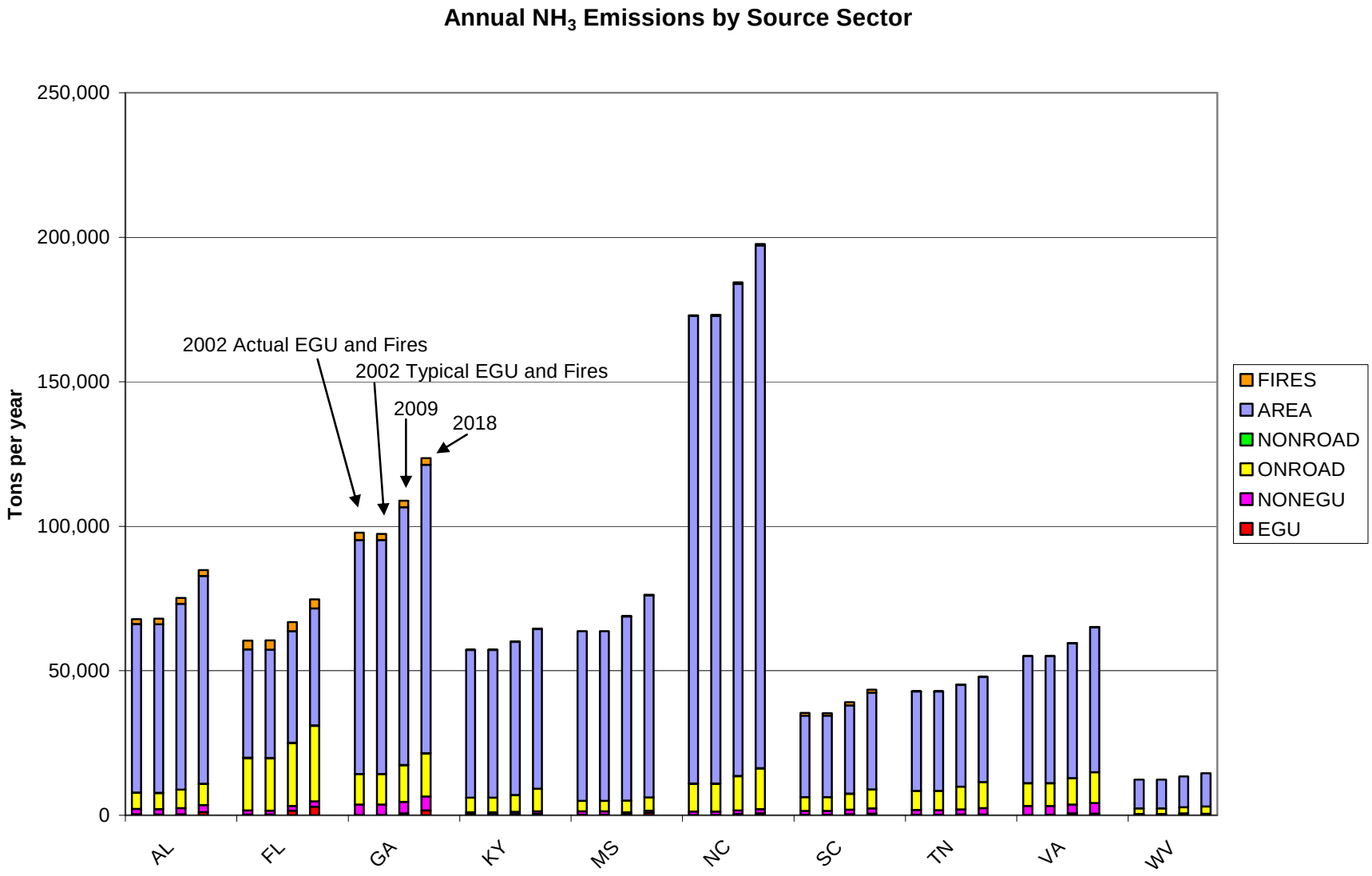
Appendix A:

STATE EMISSION TOTALS BY POLLUTANT AND SECTOR


Annual CO Emissions by Source Sector
Tons per year
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
2002 Actual EGU and Fires
2002 Typical EGU and Fires
2009
2018
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
FIRES
AREA
NONROAD
ONROAD
NONEGU
EGU

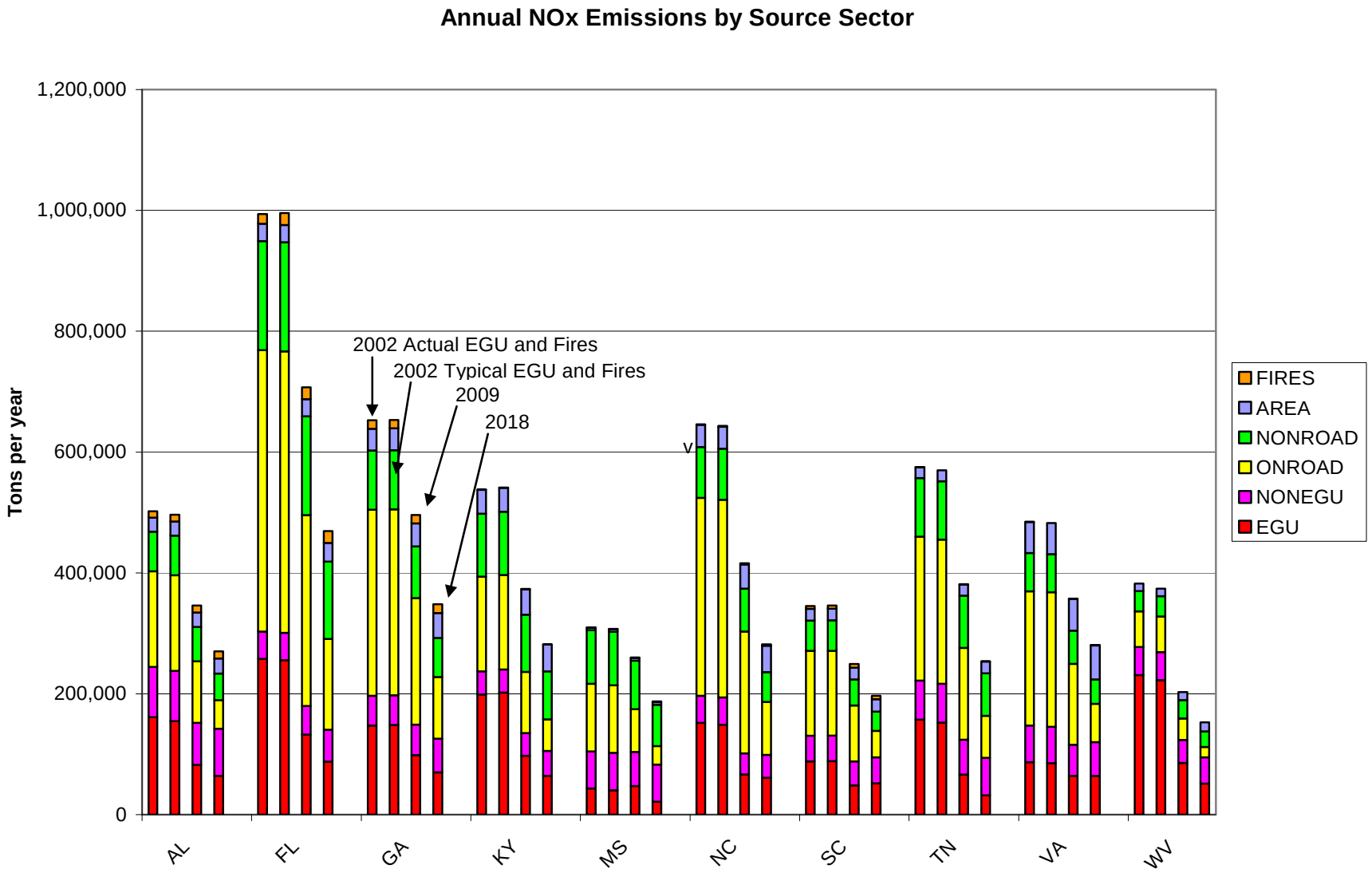
Annual CO Emissions by Source Sector

Name	EGU	NONEGU	ONROAD	NONROAD	AREA	FIRES	YEAR
AL	11,279	174,271	1,321,528	414,385	83,958	474,959	2002 Actual
	11,460	174,260	1,321,528	414,385	83,958	514,120	2002 Typical
	14,986	180,369	915,647	454,686	66,654	534,873	2009
	24,342	201,663	676,210	488,924	59,626	535,658	2018
FL	57,113	81,933	4,550,447	1,920,729	71,079	790,620	2002 Actual
	55,899	81,928	4,550,447	1,920,729	71,079	923,310	2002 Typical
	71,072	87,661	3,352,509	2,104,920	57,011	923,310	2009
	85,495	97,438	2,554,160	2,323,327	53,903	923,310	2018
GA	9,712	130,850	2,735,968	791,158	108,083	654,411	2002 Actual
	9,650	130,850	2,735,968	791,158	108,083	620,342	2002 Typical
	23,721	147,427	1,983,803	882,970	94,130	637,177	2009
	44,269	167,904	1,476,981	973,872	93,827	637,177	2018
KY	12,619	109,936	1,230,148	325,993	66,752	8,703	2002 Actual
	12,607	109,936	1,230,148	325,993	66,752	24,900	2002 Typical
	15,812	122,024	963,762	357,800	57,887	31,810	2009
	17,144	139,437	807,536	381,215	54,865	33,296	2018
MS	5,303	54,568	864,290	236,752	37,905	13,209	2002 Actual
	5,219	54,568	864,290	236,752	37,905	14,353	2002 Typical
	7,116	57,749	609,972	257,453	27,184	48,160	2009
	17,348	65,884	445,493	270,726	22,099	50,037	2018
NC	13,885	50,576	2,873,992	808,231	345,315	34,515	2002 Actual
	14,074	50,576	2,873,992	808,231	345,315	71,970	2002 Typical
	14,942	53,744	1,991,708	887,605	301,163	96,258	2009
	19,870	62,197	1,362,214	960,709	290,809	111,266	2018
SC	6,990	56,315	1,241,359	413,964	113,714	248,341	2002 Actual
	6,969	56,315	1,241,359	413,964	113,714	253,005	2002 Typical
	11,643	59,934	889,957	448,625	90,390	282,307	2009
	14,975	68,415	663,493	481,332	83,167	282,307	2018
TN	7,084	115,264	1,917,842	505,163	89,828	4,302	2002 Actual
	6,787	115,264	1,917,842	505,163	89,828	10,124	2002 Typical
	7,214	119,216	1,338,016	554,121	74,189	17,372	2009
	7,723	140,556	976,634	593,100	68,809	18,860	2018
VA	6,892	63,796	2,163,259	660,105	155,873	15,625	2002 Actual
	6,797	63,784	2,163,259	660,105	155,873	12,611	2002 Typical
	12,535	68,326	1,453,946	726,815	128,132	21,130	2009
	18,850	76,846	1,075,104	797,683	121,690	26,923	2018
WV	10,341	89,879	533,471	133,113	39,546	6,738	2002 Actual
	10,117	89,878	533,471	133,113	39,546	2,652	2002 Typical
	11,493	93,839	365,549	152,862	31,640	3,949	2009
	12,397	111,302	274,804	167,424	28,773	5,013	2018


Annual NH3 Emissions by Source Sector
Tons per year
250,000
200,000
150,000
100,000
50,000
0
2002 Actual EGU and Fires
2002 Typical EGU and Fires
2009
2018
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
FIRES
AREA
NONROAD
ONROAD
NONEGU
EGU

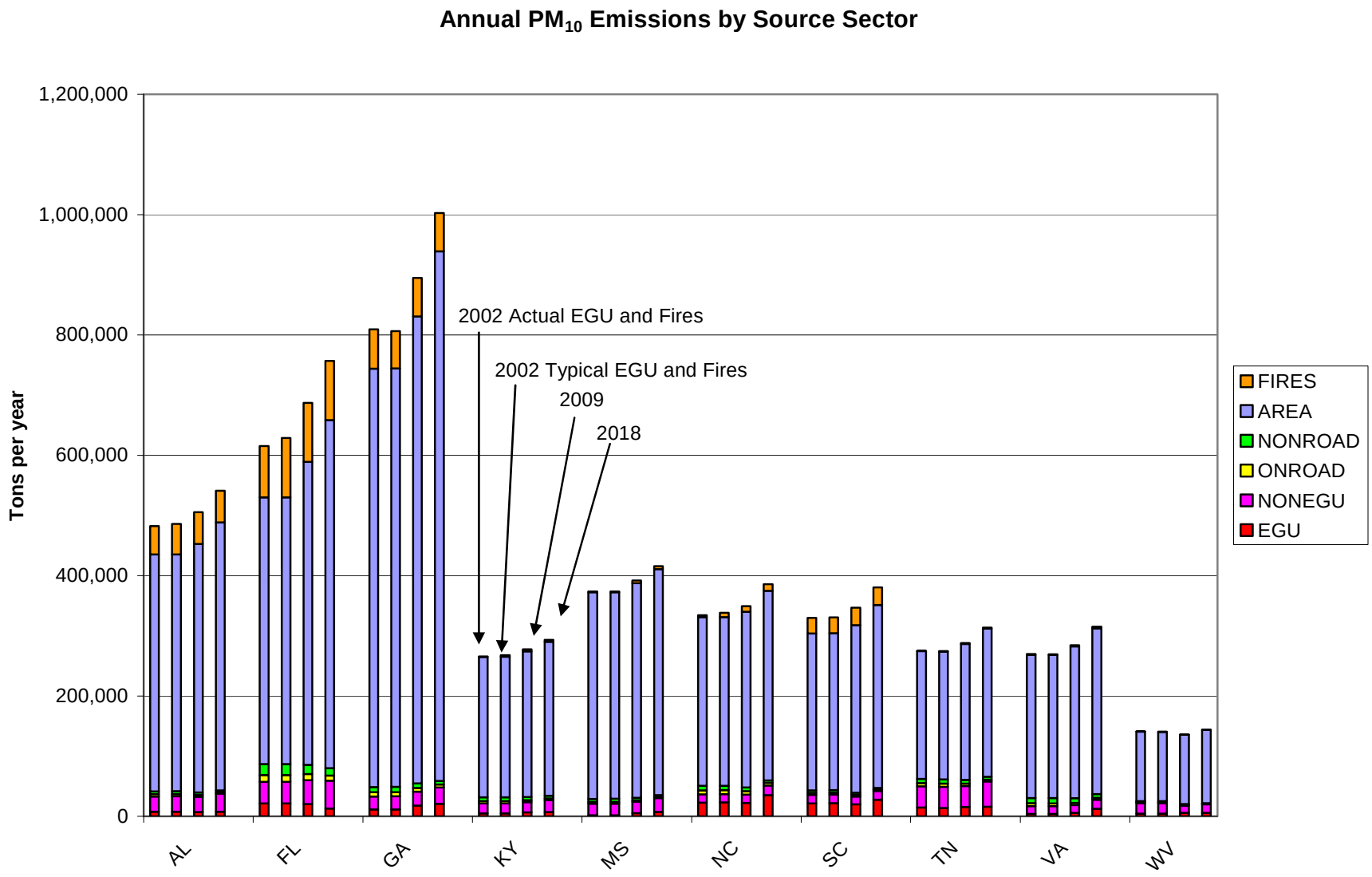
Annual NH_3 Emissions by Source Sector

Name	EGU	NONEGU	ONROAD	NONROAD	AREA	FIRES	YEAR
AL	317	1,883	5,588	33	58,318	1,689	2002 Actual
	239	1,883	5,588	33	58,318	1,957	2002 Typical
	359	2,132	6,364	36	64,268	2,050	2009
	1,072	2,464	7,298	42	71,915	2,054	2018
FL	234	1,423	18,114	134	37,446	3,102	2002 Actual
	222	1,423	18,114	134	37,446	3,157	2002 Typical
	1,629	1,544	21,781	148	38,616	3,157	2009
	2,976	1,829	26,163	171	40,432	3,157	2018
GA	83	3,613	10,546	60	80,913	2,578	2002 Actual
	86	3,613	10,546	60	80,913	2,153	2002 Typical
	686	3,963	12,687	68	89,212	2,229	2009
	1,677	4,797	14,873	79	99,885	2,229	2018
KY	326	674	5,055	31	51,135	39	2002 Actual
	321	674	5,055	31	51,135	112	2002 Typical
	400	760	5,796	34	53,005	143	2009
	476	901	7,811	40	55,211	150	2018
MS	190	1,169	3,585	23	58,721	59	2002 Actual
	198	1,169	3,585	23	58,721	65	2002 Typical
	334	668	4,035	25	63,708	217	2009
	827	764	4,566	29	69,910	225	2018
NC	54	1,179	9,702	65	161,860	155	2002 Actual
	55	1,179	9,702	65	161,860	324	2002 Typical
	445	1,285	11,825	72	170,314	433	2009
	663	1,465	14,065	83	180,866	501	2018
SC	142	1,411	4,694	33	28,166	980	2002 Actual
	141	1,411	4,694	33	28,166	908	2002 Typical
	370	1,578	5,523	36	30,555	1,039	2009
	625	1,779	6,473	41	33,496	1,039	2018
TN	204	1,613	6,625	43	34,393	19	2002 Actual
	197	1,613	6,625	43	34,393	46	2002 Typical
	227	1,840	7,782	48	35,253	78	2009
	241	2,213	9,021	55	36,291	85	2018
VA	127	3,104	7,852	48	43,905	70	2002 Actual
	130	3,104	7,852	48	43,905	57	2002 Typical
	694	3,045	9,086	53	46,639	95	2009
	606	3,604	10,624	61	50,175	121	2018
WV	121	332	1,908	9	9,963	30	2002 Actual
	121	332	1,908	9	9,963	12	2002 Typical
	330	314	2,148	11	10,625	18	2009
	143	378	2,497	13	11,504	23	2018


Annual NOx Emissions by Source Sector
Tons per year
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2002 Actual EGU and Fires
2002 Typical EGU and Fires
2009
2018
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
FIRES
AREA
NONROAD
ONROAD
NONEGU
EGU

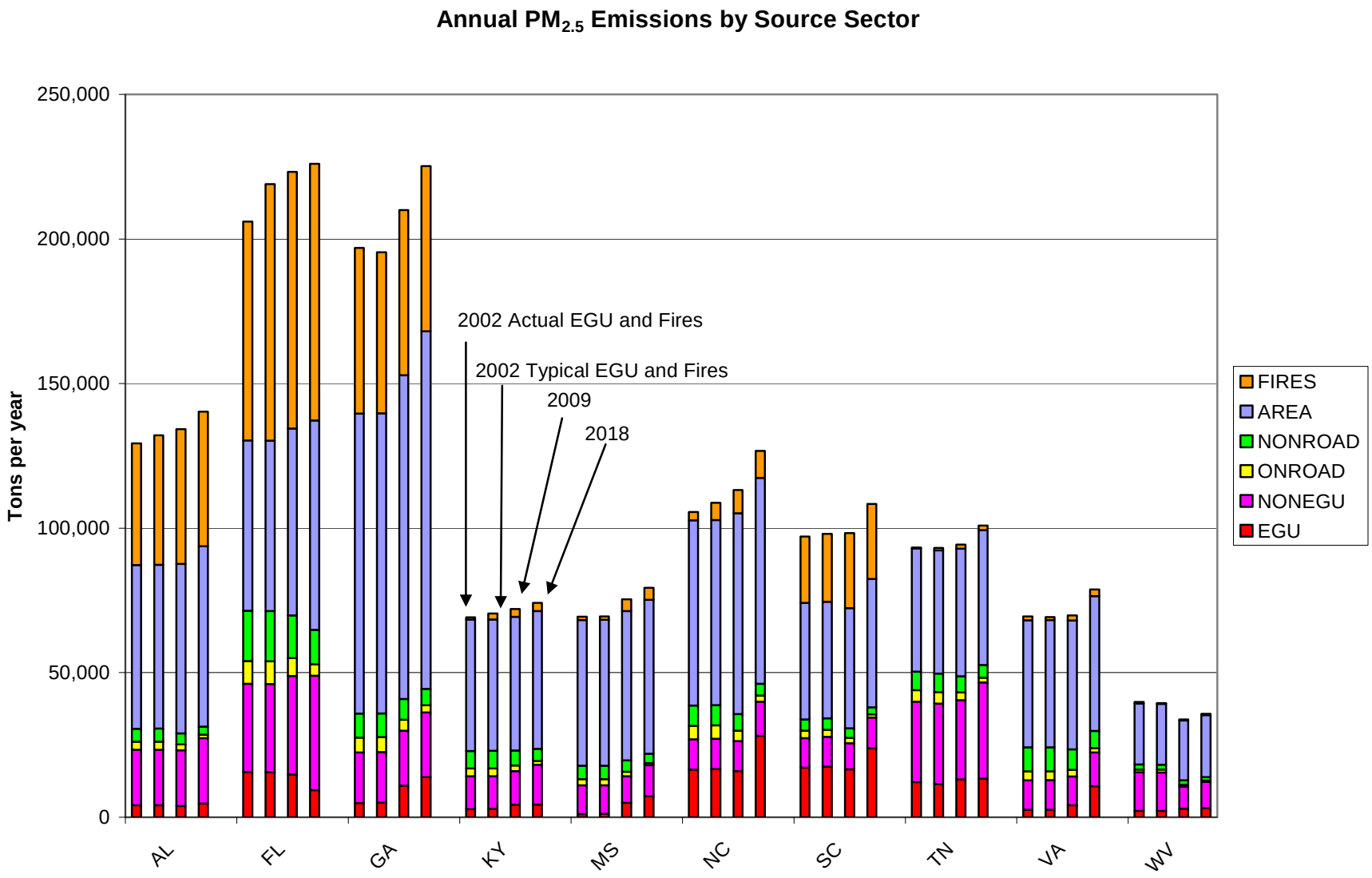
Annual NO_x Emissions by Source Sector

Name	EGU	NONEGU	ONROAD	NONROAD	AREA	FIRES	YEAR
AL	161,038	83,310	158,212	65,366	23,444	10,728	2002 Actual
	154,704	83,302	158,212	65,366	23,444	11,456	2002 Typical
	82,305	69,409	101,831	56,862	23,930	11,901	2009
	64,358	77,960	47,298	43,799	25,028	11,918	2018
FL	257,677	45,156	465,640	180,627	28,872	15,942	2002 Actual
	255,678	45,150	465,640	180,627	28,872	19,791	2002 Typical
	132,535	47,125	315,840	163,794	28,187	19,791	2009
	87,645	52,959	150,180	127,885	30,708	19,791	2018
GA	147,517	49,251	307,732	97,961	36,142	14,203	2002 Actual
	148,126	49,251	307,732	97,961	36,142	13,882	2002 Typical
	98,497	50,353	209,349	85,733	37,729	14,243	2009
	69,856	55,824	102,179	64,579	41,332	14,243	2018
KY	198,817	38,392	156,417	104,571	39,507	187	2002 Actual
	201,928	38,434	156,417	104,571	39,507	534	2002 Typical
	97,263	37,758	101,182	94,752	42,088	682	2009
	64,378	41,034	52,263	79,392	44,346	714	2018
MS	43,135	61,526	111,914	88,787	4,200	283	2002 Actual
	40,433	61,553	111,914	88,787	4,200	308	2002 Typical
	47,276	56,398	70,743	80,567	4,249	1,033	2009
	21,535	61,252	30,619	68,252	4,483	1,073	2018
NC	151,850	44,929	327,329	84,284	36,550	740	2002 Actual
	148,812	44,929	327,329	84,284	36,550	1,544	2002 Typical
	66,521	34,768	201,609	70,997	39,954	2,065	2009
	61,110	37,802	87,791	49,046	43,865	2,387	2018
SC	88,241	42,153	140,489	50,249	19,332	4,932	2002 Actual
	88,528	42,153	140,489	50,249	19,332	5,270	2002 Typical
	48,668	39,368	92,499	43,235	19,360	5,899	2009
	51,751	43,331	43,490	31,758	20,592	5,899	2018
TN	157,307	64,344	238,577	96,827	17,844	92	2002 Actual
	152,137	64,344	238,577	96,827	17,844	217	2002 Typical
	66,405	57,514	151,912	86,641	18,499	373	2009
	31,715	62,519	69,385	70,226	19,597	405	2018
VA	86,886	60,415	222,374	63,219	51,418	335	2002 Actual
	85,081	60,390	222,374	63,219	51,418	271	2002 Typical
	64,358	51,001	134,232	54,993	52,618	453	2009
	64,344	55,734	63,342	40,393	56,158	578	2018
WV	230,977	46,612	58,999	33,239	12,687	145	2002 Actual
	222,437	46,618	58,999	33,239	12,687	57	2002 Typical
	85,476	38,023	35,635	30,133	13,439	85	2009
	51,474	43,280	17,247	25,710	14,828	108	2018


Annual PM10 Emissions by Source Sector
Tons per year
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2002 Actual EGU and Fires
2002 Typical EGU and Fires
2009
2018
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
FIRES
AREA
NONROAD
ONROAD
NONEGU
EGU

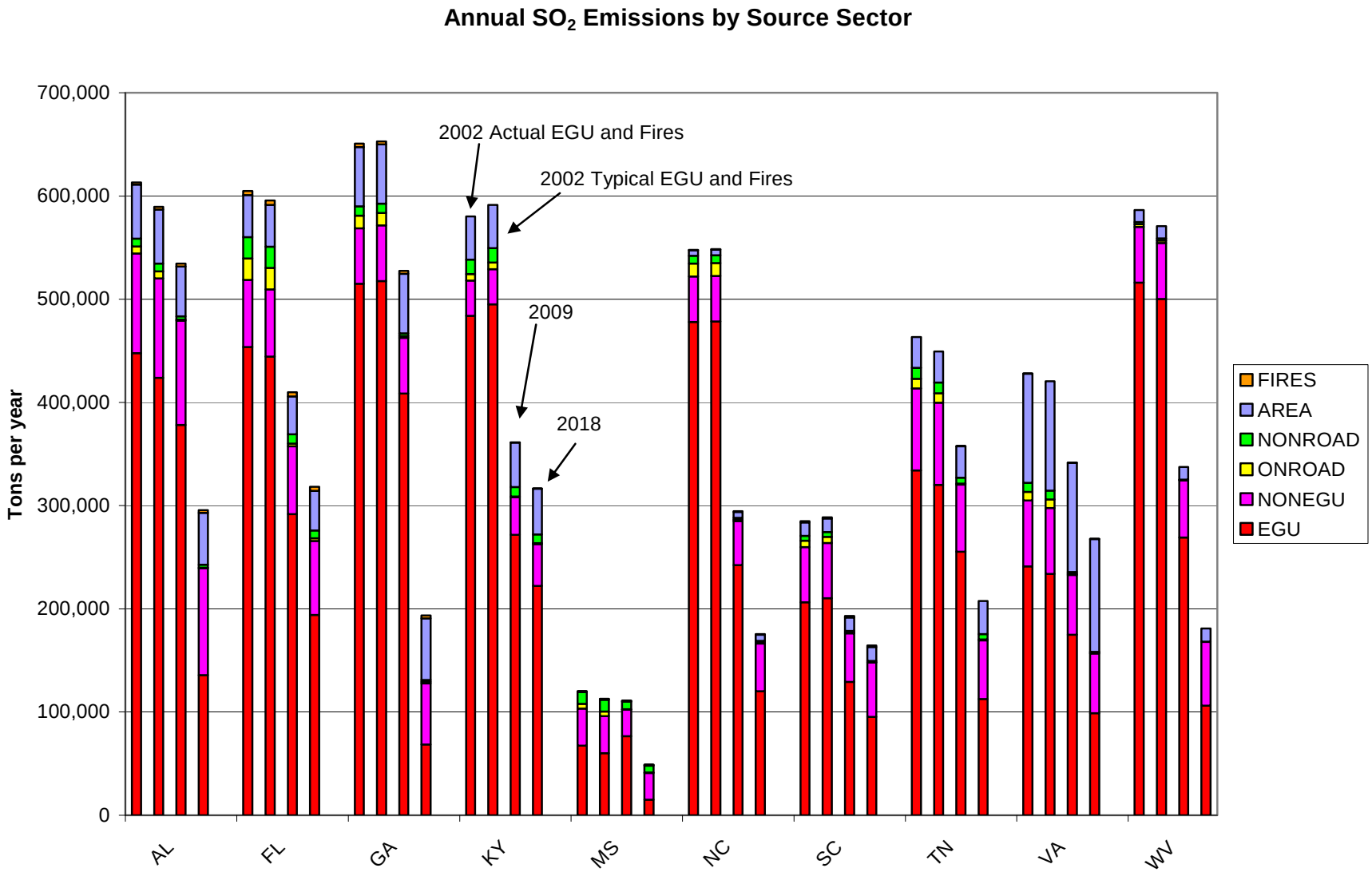
Annual PM_{10} Emissions by Source Sector

Name	EGU	NONEGU	ONROAD	NONROAD	AREA	FIRES	YEAR
AL	7,646	25,240	3,903	4,787	393,588	47,237	2002 Actual
	7,845	25,239	3,903	4,787	393,588	50,833	2002 Typical
	6,969	25,421	3,171	4,027	413,020	52,851	2009
	7,822	29,889	2,410	3,041	445,256	52,927	2018
FL	21,387	35,857	11,275	18,281	443,346	85,263	2002 Actual
	21,391	35,856	11,275	18,281	443,346	98,470	2002 Typical
	20,182	39,947	9,911	15,613	503,230	98,470	2009
	12,791	46,492	8,268	12,497	578,516	98,470	2018
GA	11,224	21,610	7,246	8,618	695,414	65,227	2002 Actual
	11,467	21,610	7,246	8,618	695,414	62,336	2002 Typical
	17,891	23,103	6,072	7,521	776,411	63,973	2009
	20,732	27,273	4,844	6,015	880,199	63,973	2018
KY	4,701	16,626	3,723	6,425	233,559	846	2002 Actual
	4,795	16,626	3,723	6,425	233,559	2,421	2002 Typical
	6,463	17,174	2,976	5,544	242,177	3,093	2009
	6,694	20,153	2,580	4,556	256,052	3,237	2018
MS	1,633	19,472	2,859	5,010	343,377	1,284	2002 Actual
	1,706	19,469	2,859	5,010	343,377	1,396	2002 Typical
	5,182	19,245	2,275	4,270	356,324	4,683	2009
	7,412	22,837	1,624	3,452	375,495	4,865	2018
NC	22,754	13,838	6,579	7,348	280,379	3,356	2002 Actual
	22,994	13,838	6,579	7,348	280,379	6,998	2002 Typical
	22,152	13,910	5,572	6,055	292,443	9,359	2009
	35,275	15,737	4,392	4,298	315,294	10,819	2018
SC	21,400	14,142	3,452	4,152	260,858	25,968	2002 Actual
	21,827	14,142	3,452	4,152	260,858	26,304	2002 Typical
	20,041	12,959	2,862	3,471	278,299	29,153	2009
	27,640	14,674	2,184	2,617	304,251	29,153	2018
TN	14,640	35,174	5,371	6,819	212,554	418	2002 Actual
	13,866	35,174	5,371	6,819	212,554	984	2002 Typical
	15,608	34,581	4,206	5,877	226,098	1,689	2009
	15,941	41,999	3,092	4,672	246,252	1,834	2018
VA	3,960	13,252	4,549	8,728	237,577	1,519	2002 Actual
	3,892	13,252	4,549	8,728	237,577	1,226	2002 Typical
	5,606	13,046	3,747	7,510	252,488	2,054	2009
	12,551	15,111	3,212	6,208	275,351	2,618	2018
WV	4,573	17,503	1,381	1,850	115,346	655	2002 Actual
	4,472	17,503	1,381	1,850	115,346	258	2002 Typical
	5,657	11,882	1,068	1,640	115,089	384	2009
	5,784	14,202	819	1,292	121,549	487	2018


Annual PM2.5 Emissions by Source Sector
Tons per year
250,000
200,000
150,000
100,000
50,000
0
2002 Actual EGU and Fires
2002 Typical EGU and Fires
2009
2018
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
FIRES
AREA
NONROAD
ONROAD
NONEGU
EGU

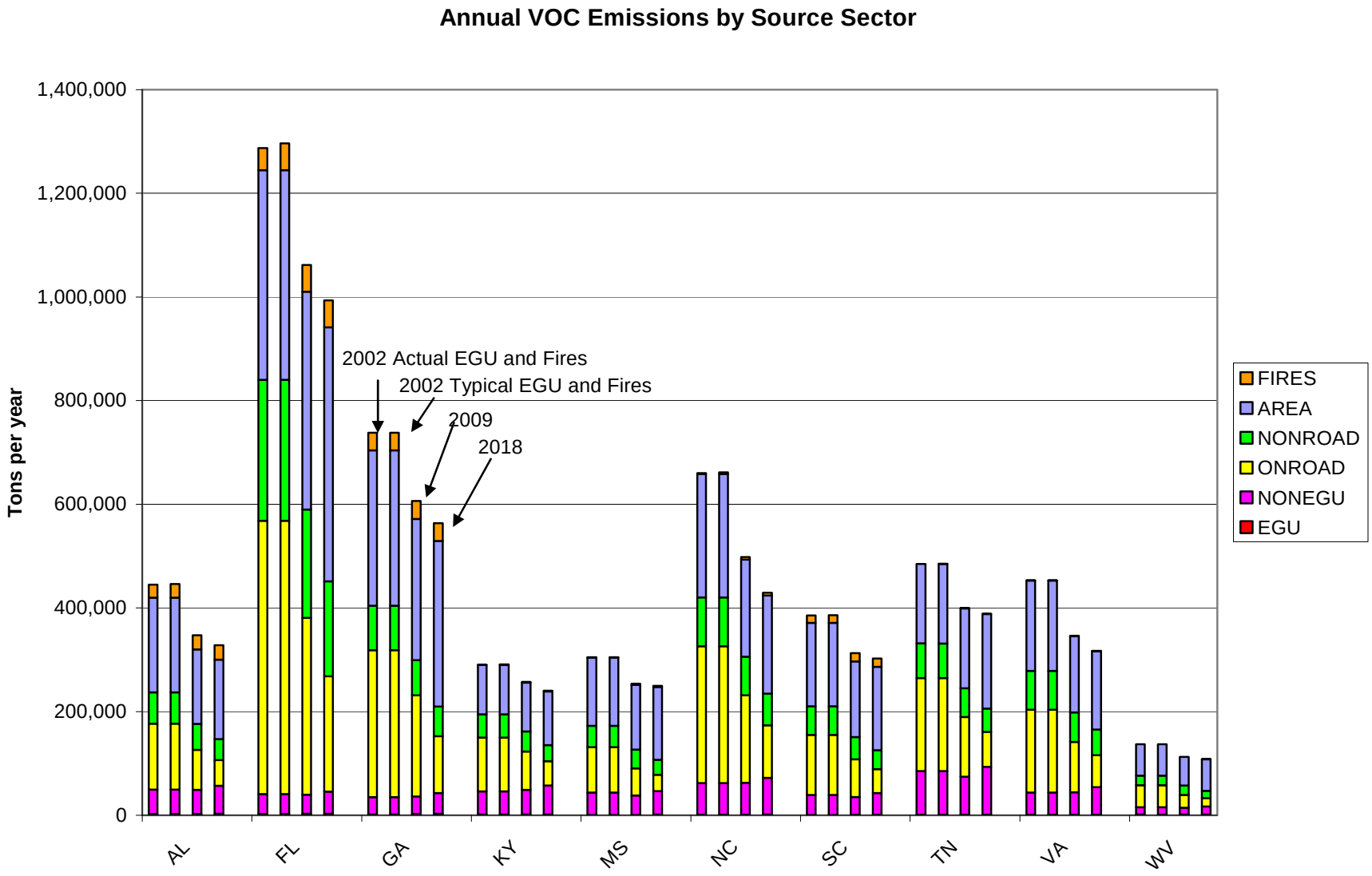
Annual $PM_{2.5}$ Emissions by Source Sector

Name	EGU	NONEGU	ONROAD	NONROAD	AREA	FIRES	YEAR
AL	4,113	19,178	2,799	4,502	56,654	42,041	2002 Actual
	4,176	19,177	2,799	4,502	56,654	44,812	2002 Typical
	3,921	19,230	2,032	3,776	58,699	46,543	2009
	4,768	22,584	1,192	2,835	62,323	46,608	2018
FL	15,643	30,504	7,868	17,415	58,878	75,717	2002 Actual
	15,575	30,504	7,868	17,415	58,878	88,756	2002 Typical
	14,790	34,019	6,173	14,866	64,589	88,756	2009
	9,417	39,486	4,038	11,868	72,454	88,756	2018
GA	4,939	17,462	5,168	8,226	103,794	57,293	2002 Actual
	5,070	17,462	5,168	8,226	103,794	55,712	2002 Typical
	10,907	18,982	3,840	7,175	112,001	57,116	2009
	13,881	22,416	2,380	5,730	123,704	57,116	2018
KY	2,802	11,372	2,697	6,046	45,453	726	2002 Actual
	2,847	11,372	2,697	6,046	45,453	2,076	2002 Typical
	4,279	11,686	1,920	5,203	46,243	2,653	2009
	4,434	13,739	1,272	4,256	47,645	2,777	2018
MS	1,138	9,906	2,112	4,690	50,401	1,102	2002 Actual
	1,147	9,902	2,112	4,690	50,401	1,197	2002 Typical
	4,996	9,199	1,508	3,985	51,661	4,016	2009
	7,252	10,719	819	3,203	53,222	4,173	2018
NC	16,498	10,500	4,623	7,005	64,052	2,878	2002 Actual
	16,623	10,500	4,623	7,005	64,052	6,002	2002 Typical
	15,949	10,458	3,493	5,760	69,457	8,027	2009
	28,137	11,825	2,123	4,069	71,262	9,279	2018
SC	17,154	10,245	2,501	3,945	40,291	22,953	2002 Actual
	17,521	10,245	2,501	3,945	40,291	23,511	2002 Typical
	16,548	9,048	1,855	3,294	41,613	25,955	2009
	23,794	10,699	1,087	2,474	44,319	25,955	2018
TN	12,166	27,807	3,949	6,458	42,566	359	2002 Actual
	11,491	27,807	3,949	6,458	42,566	844	2002 Typical
	13,092	27,367	2,751	5,557	44,124	1,449	2009
	13,387	33,293	1,544	4,403	46,692	1,573	2018
VA	2,606	10,165	3,102	8,288	43,989	1,303	2002 Actual
	2,650	10,165	3,102	8,288	43,989	1,052	2002 Typical
	4,165	9,988	2,241	7,136	44,514	1,762	'2009
	10,773	11,605	1,543	5,891	46,697	2,245	2018
WV	2,210	13,313	995	1,728	21,049	562	2002 Actual
	2,163	13,313	995	1,728	21,049	221	2002 Typical
	2,940	7,638	684	1,528	20,664	329	2009
	3,116	9,124	405	1,198	21,490	418	2018


Annual SO2 Emissions by Source Sector
Tons per year
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
2002 Actual EGU and Fires
2002 Typical EGU and Fires
2009
2018
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
FIRES
AREA
NONROAD
ONROAD
NONEGU
EGU

Annual SO_2 Emissions by Source Sector

Name	EGU	NONEGU	ONROAD	NONROAD	AREA	FIRES	YEAR
AL	447,828	96,481	6,900	7,584	52,253	2,208	2002 Actual
	423,736	96,481	6,900	7,584	52,253	2,559	2002 Typical
	378,052	101,246	810	3,471	48,228	2,681	2009
	135,851	103,303	720	2,818	50,264	2,686	2018
FL	453,631	65,090	20,915	20,614	40,491	4,057	2002 Actual
	444,383	65,090	20,915	20,614	40,491	4,129	2002 Typical
	291,831	65,651	2,612	8,967	36,699	4,129	2009
	194,028	71,810	2,533	7,536	38,317	4,129	2018
GA	514,952	53,774	12,184	9,005	57,559	3,372	2002 Actual
	517,633	53,778	12,184	9,005	57,559	2,815	2002 Typical
	408,679	53,983	1,585	2,725	57,696	2,914	2009
	68,515	59,343	1,457	1,709	59,729	2,914	2018
KY	484,057	34,029	6,308	14,043	41,805	51	2002 Actual
	495,153	34,029	6,308	14,043	41,805	146	2002 Typical
	271,669	36,418	759	9,180	43,087	187	2009
	222,102	40,682	763	8,592	44,186	196	2018
MS	67,429	35,960	4,614	11,315	771	78	2002 Actual
	60,086	35,954	4,614	11,315	771	84	2002 Typical
	76,646	25,564	537	7,191	753	283	2009
	15,213	25,674	440	6,638	746	294	2018
NC	477,990	44,123	12,420	7,693	5,412	203	2002 Actual
	478,488	44,123	12,420	7,693	5,412	423	2002 Typical
	242,286	42,536	1,503	1,892	5,751	566	2009
	120,165	46,314	1,481	905	6,085	655	2018
SC	206,399	53,518	5,972	4,866	12,900	1,281	2002 Actual
	210,272	53,518	5,972	4,866	12,900	1,187	2002 Typical
	129,122	47,193	721	1,701	13,051	1,359	2009
	95,377	52,410	643	1,198	13,457	1,359	2018
TN	334,151	79,604	9,226	10,441	29,917	25	2002 Actual
	320,146	79,604	9,226	10,441	29,917	60	2002 Typical
	255,410	64,964	1,076	5,651	30,577	102	2009
	112,672	56,682	948	5,207	31,962	111	2018
VA	241,204	63,903	8,294	8,663	105,890	92	2002 Actual
	233,691	63,900	8,294	8,663	105,890	74	2002 Typical
	174,777	58,039	1,079	1,707	105,984	124	2009
	98,988	57,790	1,043	507	109,380	158	2018
WV	516,084	54,070	2,464	2,112	11,667	40	2002 Actual
	500,381	54,077	2,464	2,112	11,667	16	2002 Typical
	268,952	55,598	279	359	12,284	23	2009
	106,199	61,702	253	56	12,849	29	2018


Annual VOC Emissions by Source Sector
Tons per year
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2002 Actual EGU and Fires
2002 Typical EGU and Fires
2009
2018
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
FIRES
AREA
NONROAD
ONROAD
NONEGU
EGU

Annual VOC Emissions by Source Sector

Name	EGU	NONEGU	ONROAD	NONROAD	AREA	FIRES	YEAR
AL	2,295	47,037	127,295	60,487	182,674	25,278	2002 Actual
	2,288	47,035	127,295	60,487	182,674	26,526	2002 Typical
	2,473	46,644	76,990	50,249	143,454	27,502	2009
	2,952	54,291	49,175	40,407	153,577	27,539	2018
FL	2,524	38,471	527,209	272,072	404,302	42,724	2002 Actual
	2,531	38,471	527,209	272,072	404,302	51,527	2002 Typical
	2,730	36,882	340,947	209,543	420,172	51,527	2009
	3,047	42,813	222,303	183,452	489,975	51,527	2018
GA	1,244	33,709	283,421	85,965	299,679	33,979	2002 Actual
	1,256	33,709	283,421	85,965	299,679	33,918	2002 Typical
	2,314	34,116	195,125	67,686	272,315	34,710	2009
	2,816	40,282	109,763	56,761	319,328	34,710	2018
KY	1,487	44,834	103,503	44,805	95,375	410	2002 Actual
	1,481	44,834	103,503	44,805	95,375	1,172	2002 Typical
	1,369	47,786	73,942	38,558	94,042	1,497	2009
	1,426	55,861	47,066	30,920	103,490	1,567	2018
MS	648	43,204	87,672	41,081	131,808	622	2002 Actual
	629	43,203	87,672	41,081	131,808	675	2002 Typical
	564	37,747	52,107	36,197	124,977	2,266	2009
	1,274	45,335	31,616	28,842	140,134	2,355	2018
NC	988	61,182	263,766	94,480	237,926	1,624	2002 Actual
	986	61,182	263,766	94,480	237,926	3,387	2002 Typical
	954	61,925	168,676	74,056	187,769	4,530	2009
	1,302	70,875	101,099	61,327	189,591	5,236	2018
SC	470	38,458	116,163	55,016	161,000	14,202	2002 Actual
	470	38,458	116,163	55,016	161,000	14,666	2002 Typical
	723	34,403	72,603	43,061	146,107	16,045	2009
	931	41,987	46,301	36,131	161,228	16,045	2018
TN	926	84,328	179,807	66,450	153,307	202	2002 Actual
	890	84,328	179,807	66,450	153,307	476	2002 Typical
	932	73,498	115,181	55,358	154,377	817	2009
	976	92,456	67,324	45,084	182,222	888	2018
VA	754	43,152	159,790	74,866	174,116	735	2002 Actual
	747	43,152	159,790	74,866	174,116	593	2002 Typical
	788	43,726	96,770	57,009	147,034	994	2009
	980	53,186	61,964	49,052	150,919	1,267	2018
WV	1,180	14,595	42,174	18,566	60,443	317	2002 Actual
	1,140	14,595	42,174	18,566	60,443	125	2002 Typical
	1,361	13,043	24,843	18,069	55,288	186	2009
	1,387	15,582	16,121	14,086	60,747	236	2018

APPENDIX B:

STATE VMT TOTALS

State VMT Totals

Million Miles Per Year

2002	LDGV	LDGT1	LDGT2	HDDV	LDDV	LDDT	HDDV	MC	TOTAL
AL	31,982	12,728	4,347	1,630	63	69	4,709	196	55,723
FL	105,340	40,835	13,945	5,079	206	220	12,465	591	178,681
GA	61,660	24,394	8,331	3,103	121	132	8,673	371	106,785
KY	28,751	12,189	3,366	1,606	55	55	4,827	171	51,020
MS	23,933	6,724	439	1,025	330	125	3,610	92	36,278
NC	51,189	30,339	10,787	4,119	230	230	9,440	461	106,795
SC	26,672	10,750	3,671	1,395	52	58	4,306	171	47,074
TN	30,809	20,272	6,922	2,943	52	111	6,810	397	68,316
VA	36,336	24,784	8,667	2,148	61	139	4,969	369	77,472
WV	9,010	5,931	2,028	732	25	37	1,664	117	19,544

2009	LDGV	LDGT1	LDGT2	HDDV	LDDV	LDDT	HDDV	MC	TOTAL
AL	30,638	18,598	5,511	2,069	65	72	5,976	249	63,178
FL	107,641	62,449	18,697	6,820	215	230	16,743	794	213,590
GA	61,569	36,641	10,933	4,077	126	137	11,374	487	125,343
KY	28,006	16,984	4,428	1,983	58	57	5,983	231	57,729
MS	23,641	10,131	573	1,341	356	135	4,719	120	41,017
NC	48,495	43,484	15,122	4,576	40	224	10,928	527	123,396
SC	26,451	16,119	4,796	1,824	55	61	5,617	223	55,147
TN	28,775	28,650	8,521	3,627	52	111	8,391	490	78,615
VA	33,663	34,814	10,597	2,624	61	137	6,073	451	88,419
WV	8,128	8,205	2,427	878	25	37	1,995	140	21,835

2018	LDGV	LDGT1	LDGT2	HDDV	LDDV	LDDT	HDDV	MC	TOTAL
AL	31,706	23,562	6,990	2,634	67	84	7,607	317	72,966
FL	116,576	83,385	24,996	9,156	221	301	22,491	1,066	258,191
GA	65,214	47,687	14,245	5,332	129	171	14,853	637	148,269
KY	29,353	21,058	5,558	2,463	60	66	7,454	288	66,300
MS	24,787	12,984	736	1,727	372	159	6,076	155	46,996
NC	42,247	51,568	18,260	4,985	279	279	11,396	553	129,566
SC	27,930	20,880	6,220	2,375	57	75	7,306	290	65,133
TN	29,253	35,702	10,629	4,538	52	130	10,500	613	91,417
VA	35,030	44,438	13,543	3,358	62	164	7,770	578	104,944
WV	8,130	10,025	2,969	1,078	25	41	2,451	172	24,891

APPENDIX C:

STATE TIER 1 EMISSION TOTALS

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
AL	2002	01	FUEL COMB. ELEC. UTIL.	11,279	317	161,038	7,646	4,113	447,828	2,295
AL	2002	02	FUEL COMB. INDUSTRIAL	67,132	234	51,535	6,730	3,792	40,918	2,239
AL	2002	03	FUEL COMB. OTHER	70,498	169	19,237	6,411	5,528	39,606	56,120
AL	2002	04	CHEMICAL & ALLIED PRODUCT MFG	5,721	35	2,032	1,220	888	12,770	7,273
AL	2002	05	METALS PROCESSING	38,247	376	6,011	9,107	7,803	14,039	3,299
AL	2002	06	PETROLEUM & RELATED INDUSTRIES	13,606	0	878	194	155	22,991	4,024
AL	2002	07	OTHER INDUSTRIAL PROCESSES	47,676	1,468	25,252	22,689	9,516	17,904	25,304
AL	2002	08	SOLVENT UTILIZATION	216	0	226	149	126	3	108,437
AL	2002	09	STORAGE & TRANSPORT	174	0	230	1,086	636	13	16,522
AL	2002	10	WASTE DISPOSAL & RECYCLING	104,914	10	4,016	15,832	14,946	489	12,612
AL	2002	11	HIGHWAY VEHICLES	1,321,528	5,588	158,212	3,903	2,799	6,900	127,295
AL	2002	12	OFF-HIGHWAY	414,385	33	65,366	4,787	4,502	7,584	60,487
AL	2002	14	MISCELLANEOUS	385,005	59,596	8,065	402,646	74,483	2,208	19,161
	2002 Total			**2,480,381**	**67,827**	**502,098**	**482,402**	**129,287**	**613,255**	**445,065**
AL	2009	01	FUEL COMB. ELEC. UTIL.	14,986	359	82,305	6,969	3,921	378,052	2,473
AL	2009	02	FUEL COMB. INDUSTRIAL	68,146	274	36,301	6,140	3,438	40,651	2,191
AL	2009	03	FUEL COMB. OTHER	52,256	158	19,514	5,904	5,104	36,048	31,403
AL	2009	04	CHEMICAL & ALLIED PRODUCT MFG	6,118	38	2,273	1,257	912	13,660	6,613
AL	2009	05	METALS PROCESSING	38,969	500	6,021	9,062	7,756	16,629	3,305
AL	2009	06	PETROLEUM & RELATED INDUSTRIES	13,241	0	858	221	177	22,495	3,336
AL	2009	07	OTHER INDUSTRIAL PROCESSES	52,004	1,571	26,340	24,196	10,197	19,383	26,519
AL	2009	08	SOLVENT UTILIZATION	247	0	257	165	139	4	92,631
AL	2009	09	STORAGE & TRANSPORT	192	0	253	1,146	584	14	17,738
AL	2009	10	WASTE DISPOSAL & RECYCLING	87,225	11	3,634	14,504	13,485	590	11,207
AL	2009	11	HIGHWAY VEHICLES	915,647	6,364	101,831	3,171	2,032	810	76,990
AL	2009	12	OFF-HIGHWAY	454,686	36	56,862	4,027	3,776	3,471	50,249
AL	2009	14	MISCELLANEOUS	463,498	65,899	9,788	428,698	82,679	2,681	22,657
	2009 Total			**2,167,216**	**75,209**	**346,238**	**505,457**	**134,201**	**534,489**	**347,312**
AL	2018	01	FUEL COMB. ELEC. UTIL.	24,342	1,072	64,358	7,822	4,768	135,851	2,952
AL	2018	02	FUEL COMB. INDUSTRIAL	69,068	275	38,424	6,427	3,599	40,126	2,293
AL	2018	03	FUEL COMB. OTHER	43,744	164	20,185	5,641	4,818	37,162	21,215
AL	2018	04	CHEMICAL & ALLIED PRODUCT MFG	7,384	46	2,804	1,523	1,106	16,509	8,040
AL	2018	05	METALS PROCESSING	49,770	674	7,519	11,036	9,423	21,824	4,234
AL	2018	06	PETROLEUM & RELATED INDUSTRIES	13,002	0	848	258	207	15,364	3,421
AL	2018	07	OTHER INDUSTRIAL PROCESSES	60,452	1,732	30,831	27,727	11,812	21,843	30,267
AL	2018	08	SOLVENT UTILIZATION	301	0	317	200	169	4	112,412
AL	2018	09	STORAGE & TRANSPORT	234	0	307	1,366	699	17	18,900
AL	2018	10	WASTE DISPOSAL & RECYCLING	88,758	13	3,867	15,343	14,143	718	11,938
AL	2018	11	HIGHWAY VEHICLES	676,210	7,298	47,298	2,410	1,192	720	49,175
AL	2018	12	OFF-HIGHWAY	488,924	42	43,799	3,041	2,835	2,818	40,407
AL	2018	14	MISCELLANEOUS	464,235	73,529	9,803	458,551	85,538	2,686	22,686
	2018 Total			**1,986,424**	**84,845**	**270,362**	**541,346**	**140,310**	**295,642**	**327,940**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
FL	2002	01	FUEL COMB. ELEC. UTIL.	57,113	234	257,677	21,387	15,643	453,631	2,524
FL	2002	02	FUEL COMB. INDUSTRIAL	64,798	131	45,157	20,442	18,547	42,524	4,219
FL	2002	03	FUEL COMB. OTHER	49,230	99	11,597	8,464	8,074	20,031	16,123
FL	2002	04	CHEMICAL & ALLIED PRODUCT MFG	745	1,101	2,221	1,868	1,488	34,462	3,542
FL	2002	05	METALS PROCESSING	1,404	1	194	449	334	882	82
FL	2002	06	PETROLEUM & RELATED INDUSTRIES	1,070	0	560	259	129	470	724
FL	2002	07	OTHER INDUSTRIAL PROCESSES	18,586	19	12,325	23,419	11,844	6,515	27,024
FL	2002	08	SOLVENT UTILIZATION	0	0	1	128	110	0	304,582
FL	2002	09	STORAGE & TRANSPORT	161	0	561	1,645	720	38	79,281
FL	2002	10	WASTE DISPOSAL & RECYCLING	54,721	351	2,535	9,943	9,405	659	9,125
FL	2002	11	HIGHWAY VEHICLES	4,550,447	18,114	465,640	11,275	7,868	20,915	527,209
FL	2002	12	OFF-HIGHWAY	1,920,729	134	180,627	18,281	17,415	20,614	272,072
FL	2002	14	MISCELLANEOUS	752,915	40,269	14,821	497,846	114,447	4,057	40,795
	2002 Total			**7,471,920**	**60,454**	**993,915**	**615,407**	**206,025**	**604,797**	**1,287,301**
FL	2009	01	FUEL COMB. ELEC. UTIL.	35,928	1,631	86,165	9,007	5,910	186,055	1,910
FL	2009	02	FUEL COMB. INDUSTRIAL	69,972	146	44,480	16,265	14,827	38,225	4,473
FL	2009	03	FUEL COMB. OTHER	33,014	100	10,800	7,555	7,174	19,882	10,907
FL	2009	04	CHEMICAL & ALLIED PRODUCT MFG	901	1,231	2,461	1,908	1,526	34,961	3,821
FL	2009	05	METALS PROCESSING	1,545	1	176	361	251	993	82
FL	2009	06	PETROLEUM & RELATED INDUSTRIES	1,190	0	612	304	156	519	748
FL	2009	07	OTHER INDUSTRIAL PROCESSES	18,593	26	13,521	33,084	19,357	6,881	26,413
FL	2009	08	SOLVENT UTILIZATION	0	0	1	132	113	0	319,723
FL	2009	09	STORAGE & TRANSPORT	187	0	621	1,661	727	50	83,880
FL	2009	10	WASTE DISPOSAL & RECYCLING	177,953	342	6,251	22,971	22,364	698	17,241
FL	2009	11	HIGHWAY VEHICLES	3,308,863	21,549	312,321	9,801	6,104	2,584	336,707
FL	2009	12	OFF-HIGHWAY	2,104,920	148	163,794	15,613	14,866	8,967	209,543
FL	2009	14	MISCELLANEOUS	764,004	41,471	15,075	557,331	120,796	4,129	41,290
	2009 Total			**6,596,484**	**66,874**	**707,273**	**687,353**	**223,192**	**406,888**	**1,061,801**
FL	2018	01	FUEL COMB. ELEC. UTIL.	85,495	2,976	87,645	12,791	9,417	194,028	3,047
FL	2018	02	FUEL COMB. INDUSTRIAL	77,465	156	48,879	17,876	16,324	37,205	4,894
FL	2018	03	FUEL COMB. OTHER	27,094	110	12,356	7,255	6,853	20,975	8,879
FL	2018	04	CHEMICAL & ALLIED PRODUCT MFG	1,200	1,448	3,119	2,367	1,907	41,395	4,739
FL	2018	05	METALS PROCESSING	1,973	2	225	466	323	1,325	106
FL	2018	06	PETROLEUM & RELATED INDUSTRIES	1,513	0	778	387	198	659	918
FL	2018	07	OTHER INDUSTRIAL PROCESSES	20,748	35	15,855	39,842	23,289	7,741	29,716
FL	2018	08	SOLVENT UTILIZATION	0	0	1	158	135	0	387,657
FL	2018	09	STORAGE & TRANSPORT	226	0	690	2,004	877	58	87,732
FL	2018	10	WASTE DISPOSAL & RECYCLING	180,730	418	6,486	24,140	23,427	769	18,335
FL	2018	11	HIGHWAY VEHICLES	2,554,160	26,163	150,180	8,268	4,038	2,533	222,303
FL	2018	12	OFF-HIGHWAY	2,323,327	171	127,885	12,497	11,868	7,536	183,452
FL	2018	14	MISCELLANEOUS	763,701	43,251	15,068	628,984	127,364	4,129	41,338
	2018 Total			**6,037,633**	**74,728**	**469,168**	**757,033**	**226,019**	**318,353**	**993,116**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
GA	2002	01	FUEL COMB. ELEC. UTIL.	9,712	83	147,517	11,224	4,939	514,952	1,244
GA	2002	02	FUEL COMB. INDUSTRIAL	59,492	27	53,039	12,037	7,886	88,791	3,956
GA	2002	03	FUEL COMB. OTHER	63,314	17	14,465	10,142	10,057	10,740	27,226
GA	2002	04	CHEMICAL & ALLIED PRODUCT MFG	5,387	920	2,277	391	305	2,721	2,668
GA	2002	05	METALS PROCESSING	330	0	60	147	94	0	70
GA	2002	06	PETROLEUM & RELATED INDUSTRIES	41	0	3	69	44	68	175
GA	2002	07	OTHER INDUSTRIAL PROCESSES	27,960	2,666	12,215	39,630	13,073	8,701	26,999
GA	2002	08	SOLVENT UTILIZATION	4	0	22	13	13	0	234,744
GA	2002	09	STORAGE & TRANSPORT	39	0	6	583	360	0	26,334
GA	2002	10	WASTE DISPOSAL & RECYCLING	146,183	16	5,164	23,422	22,506	312	15,003
GA	2002	11	HIGHWAY VEHICLES	2,735,968	10,546	307,732	7,246	5,168	12,184	283,421
GA	2002	12	OFF-HIGHWAY	791,158	60	97,961	8,618	8,226	9,005	85,965
GA	2002	14	MISCELLANEOUS	590,400	83,458	12,308	695,723	124,142	3,372	29,640
	2002 Total			**4,429,989**	**97,795**	**652,769**	**809,244**	**196,815**	**650,846**	**737,444**
GA	2009	01	FUEL COMB. ELEC. UTIL.	23,721	686	98,497	17,891	10,907	408,679	2,314
GA	2009	02	FUEL COMB. INDUSTRIAL	63,067	28	53,726	11,206	7,390	89,850	4,163
GA	2009	03	FUEL COMB. OTHER	45,184	17	15,347	8,496	8,400	10,981	15,683
GA	2009	04	CHEMICAL & ALLIED PRODUCT MFG	6,044	1,032	2,531	436	341	2,743	2,814
GA	2009	05	METALS PROCESSING	363	0	61	159	100	0	47
GA	2009	06	PETROLEUM & RELATED INDUSTRIES	50	0	4	83	54	82	154
GA	2009	07	OTHER INDUSTRIAL PROCESSES	29,976	2,902	12,528	45,339	14,758	7,662	28,441
GA	2009	08	SOLVENT UTILIZATION	4	0	25	14	14	0	216,248
GA	2009	09	STORAGE & TRANSPORT	45	0	7	649	401	0	27,821
GA	2009	10	WASTE DISPOSAL & RECYCLING	218,460	18	7,419	31,955	30,900	360	18,711
GA	2009	11	HIGHWAY VEHICLES	1,983,803	12,687	209,349	6,072	3,840	1,585	195,125
GA	2009	12	OFF-HIGHWAY	882,970	68	85,733	7,521	7,175	2,725	67,686
GA	2009	14	MISCELLANEOUS	515,329	91,406	10,637	765,043	125,665	2,914	26,388
	2009 Total			**3,769,016**	**108,844**	**495,864**	**894,865**	**209,944**	**527,582**	**605,595**
GA	2018	01	FUEL COMB. ELEC. UTIL.	44,269	1,677	69,856	20,732	13,881	68,515	2,816
GA	2018	02	FUEL COMB. INDUSTRIAL	67,067	30	57,232	11,755	7,769	94,403	4,424
GA	2018	03	FUEL COMB. OTHER	39,440	17	17,801	7,722	7,622	11,958	11,482
GA	2018	04	CHEMICAL & ALLIED PRODUCT MFG	7,076	1,208	2,982	517	405	3,436	3,524
GA	2018	05	METALS PROCESSING	421	0	76	185	118	0	55
GA	2018	06	PETROLEUM & RELATED INDUSTRIES	63	0	5	105	68	104	191
GA	2018	07	OTHER INDUSTRIAL PROCESSES	33,611	3,559	14,460	55,130	17,899	8,748	33,333
GA	2018	08	SOLVENT UTILIZATION	5	0	30	22	22	0	264,326
GA	2018	09	STORAGE & TRANSPORT	54	0	9	764	470	0	29,409
GA	2018	10	WASTE DISPOSAL & RECYCLING	235,690	22	8,120	35,280	34,038	423	20,411
GA	2018	11	HIGHWAY VEHICLES	1,476,981	14,873	102,179	4,844	2,380	1,457	109,763
GA	2018	12	OFF-HIGHWAY	973,872	79	64,579	6,015	5,730	1,709	56,761
GA	2018	14	MISCELLANEOUS	515,220	102,075	10,635	859,835	134,730	2,914	26,368
	2018 Total			**3,393,769**	**123,540**	**347,964**	**1,002,907**	**225,133**	**193,668**	**562,862**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
KY	2002	01	FUEL COMB. ELEC. UTIL.	12,619	326	198,817	4,701	2,802	484,057	1,487
KY	2002	02	FUEL COMB. INDUSTRIAL	14,110	182	60,674	2,155	1,463	41,825	1,565
KY	2002	03	FUEL COMB. OTHER	40,806	55	4,997	7,679	7,352	9,647	12,711
KY	2002	04	CHEMICAL & ALLIED PRODUCT MFG	176	214	296	774	581	2,345	3,462
KY	2002	05	METALS PROCESSING	89,197	6	1,082	3,396	2,720	12,328	1,508
KY	2002	06	PETROLEUM & RELATED INDUSTRIES	4,304	335	2,519	308	205	5,747	2,895
KY	2002	07	OTHER INDUSTRIAL PROCESSES	6,493	78	6,518	31,429	10,394	3,333	25,388
KY	2002	08	SOLVENT UTILIZATION	0	10	9	317	241	1	61,834
KY	2002	09	STORAGE & TRANSPORT	33	8	15	1,920	1,177	3	18,853
KY	2002	10	WASTE DISPOSAL & RECYCLING	20,622	8	1,768	7,229	6,476	606	7,927
KY	2002	11	HIGHWAY VEHICLES	1,230,148	5,055	156,417	3,723	2,697	6,308	103,503
KY	2002	12	OFF-HIGHWAY	325,993	31	104,571	6,425	6,046	14,043	44,805
KY	2002	14	MISCELLANEOUS	9,651	50,953	209	195,827	26,941	51	4,476
	2002 Total			**1,754,151**	**57,261**	**537,890**	**265,880**	**69,094**	**580,293**	**290,414**
KY	2009	01	FUEL COMB. ELEC. UTIL.	15,812	400	97,263	6,463	4,279	271,669	1,369
KY	2009	02	FUEL COMB. INDUSTRIAL	14,986	195	61,683	2,105	1,456	42,433	1,476
KY	2009	03	FUEL COMB. OTHER	30,045	54	5,178	7,035	6,725	10,123	9,148
KY	2009	04	CHEMICAL & ALLIED PRODUCT MFG	179	249	300	851	633	2,384	3,635
KY	2009	05	METALS PROCESSING	99,428	7	1,156	3,246	2,550	13,735	1,772
KY	2009	06	PETROLEUM & RELATED INDUSTRIES	4,818	377	2,828	344	230	6,460	3,052
KY	2009	07	OTHER INDUSTRIAL PROCESSES	7,212	84	6,674	32,194	10,912	3,634	27,548
KY	2009	08	SOLVENT UTILIZATION	0	10	11	371	283	1	62,595
KY	2009	09	STORAGE & TRANSPORT	38	9	18	2,064	1,268	3	20,038
KY	2009	10	WASTE DISPOSAL & RECYCLING	22,388	9	1,979	7,770	6,925	733	7,725
KY	2009	11	HIGHWAY VEHICLES	963,762	5,796	101,182	2,976	1,920	759	73,942
KY	2009	12	OFF-HIGHWAY	357,800	34	94,752	5,544	5,203	9,180	38,558
KY	2009	14	MISCELLANEOUS	32,627	52,915	702	206,463	29,601	187	6,335
	2009 Total			**1,549,096**	**60,139**	**373,725**	**277,427**	**71,984**	**361,300**	**257,193**
KY	2018	01	FUEL COMB. ELEC. UTIL.	17,144	476	64,378	6,694	4,434	222,102	1,426
KY	2018	02	FUEL COMB. INDUSTRIAL	15,692	205	64,533	2,203	1,528	43,772	1,555
KY	2018	03	FUEL COMB. OTHER	24,764	53	5,550	6,469	6,169	9,947	7,479
KY	2018	04	CHEMICAL & ALLIED PRODUCT MFG	219	317	367	1,054	781	2,884	4,384
KY	2018	05	METALS PROCESSING	114,470	9	1,508	3,898	3,065	15,800	2,343
KY	2018	06	PETROLEUM & RELATED INDUSTRIES	5,495	434	3,244	392	262	7,426	3,394
KY	2018	07	OTHER INDUSTRIAL PROCESSES	8,303	93	7,872	35,349	12,377	4,141	31,394
KY	2018	08	SOLVENT UTILIZATION	0	12	14	464	352	1	73,525
KY	2018	09	STORAGE & TRANSPORT	44	10	21	2,408	1,481	4	21,196
KY	2018	10	WASTE DISPOSAL & RECYCLING	24,677	11	2,256	8,481	7,518	894	8,392
KY	2018	11	HIGHWAY VEHICLES	807,536	7,811	52,263	2,580	1,272	763	47,066
KY	2018	12	OFF-HIGHWAY	381,215	40	79,392	4,556	4,256	8,592	30,920
KY	2018	14	MISCELLANEOUS	33,931	55,118	729	218,725	30,626	196	7,254
	2018 Total			**1,433,491**	**64,588**	**282,127**	**293,273**	**74,122**	**316,520**	**240,329**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
MS	2002	01	FUEL COMB. ELEC. UTIL.	5,303	190	43,135	1,633	1,138	67,429	648
MS	2002	02	FUEL COMB. INDUSTRIAL	22,711	28	48,699	5,011	3,638	9,746	8,024
MS	2002	03	FUEL COMB. OTHER	36,752	34	4,502	5,445	5,414	789	22,923
MS	2002	04	CHEMICAL & ALLIED PRODUCT MFG	15,410	361	1,725	849	440	1,663	2,375
MS	2002	05	METALS PROCESSING	1,031	0	115	122	58	36	371
MS	2002	06	PETROLEUM & RELATED INDUSTRIES	975	20	1,187	790	335	15,560	20,788
MS	2002	07	OTHER INDUSTRIAL PROCESSES	13,884	747	9,219	27,617	8,051	8,866	15,525
MS	2002	08	SOLVENT UTILIZATION	45	7	105	219	178	1	80,760
MS	2002	09	STORAGE & TRANSPORT	74	0	80	124	38	40	23,327
MS	2002	10	WASTE DISPOSAL & RECYCLING	1,414	9	89	447	324	31	886
MS	2002	11	HIGHWAY VEHICLES	864,290	3,585	111,914	2,859	2,112	4,614	87,672
MS	2002	12	OFF-HIGHWAY	236,752	23	88,787	5,010	4,690	11,315	41,081
MS	2002	14	MISCELLANEOUS	13,386	58,741	288	323,511	42,932	78	654
	2002 Total			**1,212,028**	**63,748**	**309,845**	**373,637**	**69,348**	**120,166**	**305,035**
MS	2009	01	FUEL COMB. ELEC. UTIL.	7,116	334	47,276	5,182	4,996	76,646	564
MS	2009	02	FUEL COMB. INDUSTRIAL	24,607	30	44,095	3,728	2,787	7,388	8,007
MS	2009	03	FUEL COMB. OTHER	26,024	33	4,514	5,278	5,245	751	17,445
MS	2009	04	CHEMICAL & ALLIED PRODUCT MFG	16,141	405	1,955	941	488	1,880	2,614
MS	2009	05	METALS PROCESSING	1,098	0	128	129	62	37	402
MS	2009	06	PETROLEUM & RELATED INDUSTRIES	1,101	23	1,262	894	379	7,926	13,317
MS	2009	07	OTHER INDUSTRIAL PROCESSES	14,181	197	8,376	31,380	8,628	8,254	16,282
MS	2009	08	SOLVENT UTILIZATION	50	8	118	239	194	1	80,393
MS	2009	09	STORAGE & TRANSPORT	92	0	100	172	59	49	23,494
MS	2009	10	WASTE DISPOSAL & RECYCLING	1,486	10	95	473	339	32	743
MS	2009	11	HIGHWAY VEHICLES	609,972	4,035	70,743	2,275	1,508	537	52,107
MS	2009	12	OFF-HIGHWAY	257,453	25	80,567	4,270	3,985	7,191	36,197
MS	2009	14	MISCELLANEOUS	48,314	63,886	1,037	337,018	46,695	283	2,295
	2009 Total			**1,007,634**	**68,987**	**260,266**	**391,978**	**75,365**	**110,975**	**253,858**
MS	2018	01	FUEL COMB. ELEC. UTIL.	17,348	827	21,535	7,412	7,252	15,213	1,274
MS	2018	02	FUEL COMB. INDUSTRIAL	26,082	33	46,792	4,073	3,039	5,167	8,556
MS	2018	03	FUEL COMB. OTHER	20,900	32	4,768	4,964	4,928	726	14,670
MS	2018	04	CHEMICAL & ALLIED PRODUCT MFG	20,175	475	2,337	1,132	588	2,242	3,290
MS	2018	05	METALS PROCESSING	1,357	0	167	160	79	48	461
MS	2018	06	PETROLEUM & RELATED INDUSTRIES	1,267	26	1,294	1,010	430	8,484	14,407
MS	2018	07	OTHER INDUSTRIAL PROCESSES	16,267	216	9,996	38,492	10,492	9,657	20,301
MS	2018	08	SOLVENT UTILIZATION	60	9	141	301	244	1	98,354
MS	2018	09	STORAGE & TRANSPORT	115	0	124	210	73	62	24,537
MS	2018	10	WASTE DISPOSAL & RECYCLING	1,638	12	114	533	372	34	870
MS	2018	11	HIGHWAY VEHICLES	445,493	4,566	30,619	1,624	819	440	31,616
MS	2018	12	OFF-HIGHWAY	270,726	29	68,252	3,452	3,203	6,638	28,842
MS	2018	14	MISCELLANEOUS	50,160	70,096	1,076	352,321	47,869	294	2,377
	2018 Total			**871,587**	**76,321**	**187,215**	**415,685**	**79,388**	**49,006**	**249,556**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
NC	2002	01	FUEL COMB. ELEC. UTIL.	13,885	54	151,850	22,754	16,498	477,990	988
NC	2002	02	FUEL COMB. INDUSTRIAL	23,578	301	48,590	5,596	4,334	33,395	2,540
NC	2002	03	FUEL COMB. OTHER	217,008	2,318	16,460	31,777	26,746	3,971	87,985
NC	2002	04	CHEMICAL & ALLIED PRODUCT MFG	13,952	535	859	866	538	5,736	4,313
NC	2002	05	METALS PROCESSING	5,876	60	201	564	467	1,010	2,512
NC	2002	06	PETROLEUM & RELATED INDUSTRIES	461	0	174	104	52	283	140
NC	2002	07	OTHER INDUSTRIAL PROCESSES	8,552	480	7,380	25,328	8,924	3,426	18,025
NC	2002	08	SOLVENT UTILIZATION	130	307	229	524	484	26	151,383
NC	2002	09	STORAGE & TRANSPORT	66	46	53	639	354	1	16,120
NC	2002	10	WASTE DISPOSAL & RECYCLING	125,528	247	7,482	2,239	2,218	1,666	15,568
NC	2002	11	HIGHWAY VEHICLES	2,873,992	9,702	327,329	6,579	4,623	12,420	263,766
NC	2002	12	OFF-HIGHWAY	808,231	65	84,284	7,348	7,005	7,693	94,480
NC	2002	14	MISCELLANEOUS	35,218	158,900	757	229,909	33,291	203	1,765
	2002 Total			**4,126,478**	**173,014**	**645,648**	**334,226**	**105,533**	**547,821**	**659,585**
NC	2009	01	FUEL COMB. ELEC. UTIL.	14,942	445	66,516	22,152	15,949	242,286	954
NC	2009	02	FUEL COMB. INDUSTRIAL	24,871	312	38,161	5,159	3,871	30,788	2,510
NC	2009	03	FUEL COMB. OTHER	158,837	2,723	18,441	25,334	19,467	4,060	49,819
NC	2009	04	CHEMICAL & ALLIED PRODUCT MFG	14,732	599	933	981	607	6,286	4,925
NC	2009	05	METALS PROCESSING	6,358	67	207	627	528	1,130	2,790
NC	2009	06	PETROLEUM & RELATED INDUSTRIES	556	0	212	127	64	349	162
NC	2009	07	OTHER INDUSTRIAL PROCESSES	9,211	507	8,061	28,524	9,788	3,712	18,144
NC	2009	08	SOLVENT UTILIZATION	142	335	246	549	506	28	136,114
NC	2009	09	STORAGE & TRANSPORT	75	51	55	696	380	1	17,367
NC	2009	10	WASTE DISPOSAL & RECYCLING	139,518	307	8,354	2,774	2,750	1,913	17,331
NC	2009	11	HIGHWAY VEHICLES	1,991,708	11,825	201,609	5,572	3,493	1,503	168,676
NC	2009	12	OFF-HIGHWAY	887,605	72	70,997	6,055	5,760	1,892	74,056
NC	2009	14	MISCELLANEOUS	96,825	167,131	2,080	250,912	49,956	566	4,648
	2009 Total			**3,345,380**	**184,373**	**415,874**	**349,461**	**113,118**	**294,514**	**497,496**
NC	2018	01	FUEL COMB. ELEC. UTIL.	19,870	663	61,103	35,275	28,137	120,165	1,302
NC	2018	02	FUEL COMB. INDUSTRIAL	26,873	341	40,898	5,594	4,222	32,507	2,702
NC	2018	03	FUEL COMB. OTHER	131,365	2,857	20,027	21,847	16,231	4,050	34,104
NC	2018	04	CHEMICAL & ALLIED PRODUCT MFG	18,463	702	1,105	1,175	726	7,414	6,113
NC	2018	05	METALS PROCESSING	7,576	76	255	771	657	1,335	3,516
NC	2018	06	PETROLEUM & RELATED INDUSTRIES	712	0	272	162	82	448	207
NC	2018	07	OTHER INDUSTRIAL PROCESSES	10,675	559	9,259	34,339	11,601	4,357	20,978
NC	2018	08	SOLVENT UTILIZATION	169	375	277	588	540	31	152,979
NC	2018	09	STORAGE & TRANSPORT	91	59	67	808	430	2	19,511
NC	2018	10	WASTE DISPOSAL & RECYCLING	156,599	387	9,456	3,502	3,474	2,234	19,789
NC	2018	11	HIGHWAY VEHICLES	1,362,214	14,065	87,791	4,392	2,123	1,481	101,099
NC	2018	12	OFF-HIGHWAY	960,709	83	49,046	4,298	4,069	905	61,327
NC	2018	14	MISCELLANEOUS	111,705	177,474	2,399	273,030	54,376	655	5,333
	2018 Total			**2,807,022**	**197,643**	**281,955**	**385,780**	**126,667**	**175,583**	**428,960**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
SC	2002	01	FUEL COMB. ELEC. UTIL.	6,990	142	88,241	21,400	17,154	206,399	470
SC	2002	02	FUEL COMB. INDUSTRIAL	31,771	97	38,081	5,308	3,641	44,958	1,338
SC	2002	03	FUEL COMB. OTHER	75,800	65	4,367	6,261	6,166	4,318	49,171
SC	2002	04	CHEMICAL & ALLIED PRODUCT MFG	2,526	173	25	501	318	59	8,784
SC	2002	05	METALS PROCESSING	13,833	0	450	639	408	4,160	660
SC	2002	06	PETROLEUM & RELATED INDUSTRIES	248	0	283	120	71	170	114
SC	2002	07	OTHER INDUSTRIAL PROCESSES	9,502	1,237	15,145	15,224	6,981	12,128	16,342
SC	2002	08	SOLVENT UTILIZATION	0	1	1	78	60	0	88,878
SC	2002	09	STORAGE & TRANSPORT	10	0	4	1,025	626	0	21,009
SC	2002	10	WASTE DISPOSAL & RECYCLING	44,844	10	3,380	6,852	6,321	625	13,708
SC	2002	11	HIGHWAY VEHICLES	1,241,359	4,694	140,489	3,452	2,501	5,972	116,163
SC	2002	12	OFF-HIGHWAY	413,964	33	50,249	4,152	3,945	4,866	55,016
SC	2002	14	MISCELLANEOUS	239,836	28,975	4,678	264,959	48,898	1,281	13,655
	2002 Total			**2,080,683**	**35,426**	**345,395**	**329,971**	**97,090**	**284,936**	**385,308**
SC	2009	01	FUEL COMB. ELEC. UTIL.	11,643	370	48,668	20,041	16,548	129,122	723
SC	2009	02	FUEL COMB. INDUSTRIAL	32,661	105	35,011	2,978	2,087	36,660	1,374
SC	2009	03	FUEL COMB. OTHER	49,914	63	4,551	5,264	5,183	4,359	25,073
SC	2009	04	CHEMICAL & ALLIED PRODUCT MFG	2,798	173	26	543	345	60	7,409
SC	2009	05	METALS PROCESSING	15,632	0	448	631	378	4,856	663
SC	2009	06	PETROLEUM & RELATED INDUSTRIES	302	0	340	145	86	200	131
SC	2009	07	OTHER INDUSTRIAL PROCESSES	10,241	1,403	15,069	18,201	7,997	13,443	15,425
SC	2009	08	SOLVENT UTILIZATION	1	1	1	75	58	0	94,590
SC	2009	09	STORAGE & TRANSPORT	13	0	5	569	352	0	21,987
SC	2009	10	WASTE DISPOSAL & RECYCLING	70,379	11	4,215	9,526	8,977	666	15,998
SC	2009	11	HIGHWAY VEHICLES	889,957	5,523	92,499	2,862	1,855	721	72,603
SC	2009	12	OFF-HIGHWAY	448,625	36	43,235	3,471	3,294	1,701	43,061
SC	2009	14	MISCELLANEOUS	250,690	31,416	4,962	282,480	51,151	1,359	13,906
	2009 Total			**1,782,856**	**39,101**	**249,028**	**346,786**	**98,312**	**193,147**	**312,943**
SC	2018	01	FUEL COMB. ELEC. UTIL.	14,975	625	51,751	27,640	23,794	95,377	931
SC	2018	02	FUEL COMB. INDUSTRIAL	35,532	113	36,645	3,683	2,548	38,548	1,482
SC	2018	03	FUEL COMB. OTHER	39,627	65	5,135	4,791	4,711	4,469	16,391
SC	2018	04	CHEMICAL & ALLIED PRODUCT MFG	3,296	212	32	664	423	74	9,107
SC	2018	05	METALS PROCESSING	18,853	0	585	773	476	5,920	867
SC	2018	06	PETROLEUM & RELATED INDUSTRIES	389	0	438	186	110	258	166
SC	2018	07	OTHER INDUSTRIAL PROCESSES	12,136	1,566	17,507	20,128	8,981	15,863	18,290
SC	2018	08	SOLVENT UTILIZATION	1	1	1	93	72	0	119,154
SC	2018	09	STORAGE & TRANSPORT	16	0	6	1,380	842	0	22,739
SC	2018	10	WASTE DISPOSAL & RECYCLING	73,403	13	4,512	10,038	9,443	735	17,167
SC	2018	11	HIGHWAY VEHICLES	663,493	6,473	43,490	2,184	1,087	643	46,301
SC	2018	12	OFF-HIGHWAY	481,332	41	31,758	2,617	2,474	1,198	36,131
SC	2018	14	MISCELLANEOUS	250,637	34,345	4,961	306,342	53,367	1,359	13,896
	2018 Total			**1,593,690**	**43,455**	**196,820**	**380,519**	**108,327**	**164,444**	**302,623**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
TN	2002	01	FUEL COMB. ELEC. UTIL.	7,084	204	157,307	14,640	12,166	334,151	926
TN	2002	02	FUEL COMB. INDUSTRIAL	15,257	6	44,510	8,015	6,649	74,146	2,021
TN	2002	03	FUEL COMB. OTHER	77,857	25	15,568	7,967	7,549	16,253	18,346
TN	2002	04	CHEMICAL & ALLIED PRODUCT MFG	36,920	1,518	1,772	3,246	2,201	6,516	24,047
TN	2002	05	METALS PROCESSING	41,371	14	1,182	7,620	7,030	5,818	6,898
TN	2002	06	PETROLEUM & RELATED INDUSTRIES	543	0	331	314	243	383	1,850
TN	2002	07	OTHER INDUSTRIAL PROCESSES	9,420	44	11,794	30,484	12,867	5,845	27,336
TN	2002	08	SOLVENT UTILIZATION	275	1	5,066	2,103	1,818	58	110,872
TN	2002	09	STORAGE & TRANSPORT	22	24	105	1,249	736	134	21,962
TN	2002	10	WASTE DISPOSAL & RECYCLING	22,143	31	1,839	7,068	6,469	349	15,505
TN	2002	11	HIGHWAY VEHICLES	1,917,842	6,625	238,577	5,371	3,949	9,226	179,807
TN	2002	12	OFF-HIGHWAY	505,163	43	96,827	6,819	6,458	10,441	66,450
TN	2002	14	MISCELLANEOUS	5,003	34,292	100	179,440	24,708	25	1,978
	2002 Total			**2,638,901**	**42,825**	**574,980**	**274,337**	**92,841**	**463,345**	**477,997**
TN	2009	01	FUEL COMB. ELEC. UTIL.	7,214	227	66,405	15,608	13,092	255,410	932
TN	2009	02	FUEL COMB. INDUSTRIAL	15,536	6	37,046	7,157	5,973	63,076	1,773
TN	2009	03	FUEL COMB. OTHER	61,442	27	14,792	7,134	6,786	16,955	12,781
TN	2009	04	CHEMICAL & ALLIED PRODUCT MFG	35,440	1,719	1,958	3,369	2,271	1,949	15,492
TN	2009	05	METALS PROCESSING	45,183	15	1,245	7,337	6,823	6,537	7,671
TN	2009	06	PETROLEUM & RELATED INDUSTRIES	572	0	328	355	276	263	1,401
TN	2009	07	OTHER INDUSTRIAL PROCESSES	9,911	62	12,635	32,599	13,687	6,240	28,338
TN	2009	08	SOLVENT UTILIZATION	309	1	5,983	2,431	2,095	65	112,264
TN	2009	09	STORAGE & TRANSPORT	26	31	12	1,218	733	42	23,686
TN	2009	10	WASTE DISPOSAL & RECYCLING	23,810	35	1,993	7,618	6,968	393	14,922
TN	2009	11	HIGHWAY VEHICLES	1,338,016	7,782	151,912	4,206	2,751	1,076	115,181
TN	2009	12	OFF-HIGHWAY	554,121	48	86,641	5,877	5,557	5,651	55,358
TN	2009	14	MISCELLANEOUS	17,921	35,200	379	192,464	26,830	102	2,814
	2009 Total			**2,109,500**	**45,152**	**381,331**	**287,371**	**93,842**	**357,760**	**392,612**
TN	2018	01	FUEL COMB. ELEC. UTIL.	7,723	241	31,715	15,941	13,387	112,672	976
TN	2018	02	FUEL COMB. INDUSTRIAL	16,702	7	38,028	7,648	6,408	47,982	1,905
TN	2018	03	FUEL COMB. OTHER	54,486	30	15,502	6,757	6,412	18,091	10,269
TN	2018	04	CHEMICAL & ALLIED PRODUCT MFG	45,455	2,053	2,424	4,263	2,888	6,563	19,950
TN	2018	05	METALS PROCESSING	52,834	17	1,589	9,579	8,953	7,790	9,950
TN	2018	06	PETROLEUM & RELATED INDUSTRIES	665	0	378	414	324	309	1,598
TN	2018	07	OTHER INDUSTRIAL PROCESSES	10,946	88	14,157	38,196	16,242	7,286	35,126
TN	2018	08	SOLVENT UTILIZATION	380	1	7,675	3,154	2,717	79	140,760
TN	2018	09	STORAGE & TRANSPORT	33	41	14	1,571	939	49	25,491
TN	2018	10	WASTE DISPOSAL & RECYCLING	26,712	42	2,326	8,562	7,828	468	17,530
TN	2018	11	HIGHWAY VEHICLES	976,634	9,021	69,385	3,092	1,544	948	67,324
TN	2018	12	OFF-HIGHWAY	593,100	55	70,226	4,672	4,403	5,207	45,084
TN	2018	14	MISCELLANEOUS	19,210	36,213	408	209,058	28,209	111	3,293
	2018 Total			**1,804,879**	**47,809**	**253,828**	**312,906**	**100,255**	**207,555**	**379,257**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
VA	2002	01	FUEL COMB. ELEC. UTIL.	6,892	127	86,886	3,960	2,606	241,204	754
VA	2002	02	FUEL COMB. INDUSTRIAL	64,398	100	75,831	18,480	8,453	137,451	5,332
VA	2002	03	FUEL COMB. OTHER	98,788	13	15,648	11,572	11,236	5,508	54,496
VA	2002	04	CHEMICAL & ALLIED PRODUCT MFG	321	2,158	8,062	449	393	2,126	1,530
VA	2002	05	METALS PROCESSING	3,580	0	937	1,575	1,349	5,251	513
VA	2002	06	PETROLEUM & RELATED INDUSTRIES	23,384	0	182	255	153	170	501
VA	2002	07	OTHER INDUSTRIAL PROCESSES	12,002	726	9,279	33,409	9,795	17,702	13,086
VA	2002	08	SOLVENT UTILIZATION	0	4	0	225	210	2	111,511
VA	2002	09	STORAGE & TRANSPORT	16	7	11	745	505	0	26,121
VA	2002	10	WASTE DISPOSAL & RECYCLING	16,566	109	1,866	3,152	1,277	1,581	4,065
VA	2002	11	HIGHWAY VEHICLES	2,163,259	7,852	222,374	4,549	3,102	8,294	159,790
VA	2002	12	OFF-HIGHWAY	660,105	48	63,219	8,728	8,288	8,663	74,866
VA	2002	14	MISCELLANEOUS	16,238	43,961	350	182,486	22,086	92	848
	2002 Total			**3,065,551**	**55,105**	**484,646**	**269,585**	**69,453**	**428,046**	**453,413**
VA	2009	01	FUEL COMB. ELEC. UTIL.	12,535	694	64,358	5,606	4,165	174,777	788
VA	2009	02	FUEL COMB. INDUSTRIAL	67,422	105	67,263	18,346	8,345	131,459	5,483
VA	2009	03	FUEL COMB. OTHER	66,016	10	15,920	10,059	9,741	5,118	28,062
VA	2009	04	CHEMICAL & ALLIED PRODUCT MFG	286	2,082	7,790	477	413	1,996	1,419
VA	2009	05	METALS PROCESSING	3,397	0	827	1,563	1,332	4,813	390
VA	2009	06	PETROLEUM & RELATED INDUSTRIES	26,288	0	197	275	169	187	557
VA	2009	07	OTHER INDUSTRIAL PROCESSES	12,471	733	9,425	33,961	9,984	18,643	13,394
VA	2009	08	SOLVENT UTILIZATION	0	5	0	248	231	3	110,127
VA	2009	09	STORAGE & TRANSPORT	17	7	12	797	544	0	26,456
VA	2009	10	WASTE DISPOSAL & RECYCLING	20,109	119	2,174	3,823	1,515	1,805	4,789
VA	2009	11	HIGHWAY VEHICLES	1,453,946	9,086	134,232	3,747	2,241	1,079	96,770
VA	2009	12	OFF-HIGHWAY	726,815	53	54,993	7,510	7,136	1,707	57,009
VA	2009	14	MISCELLANEOUS	21,582	46,719	464	198,040	23,990	124	1,077
	2009 Total			**2,410,884**	**59,612**	**357,655**	**284,451**	**69,806**	**341,710**	**346,321**
VA	2018	01	FUEL COMB. ELEC. UTIL.	18,850	606	64,344	12,551	10,773	98,988	980
VA	2018	02	FUEL COMB. INDUSTRIAL	72,065	114	70,132	19,247	8,904	134,790	5,861
VA	2018	03	FUEL COMB. OTHER	53,171	14	17,852	9,427	9,086	5,230	18,603
VA	2018	04	CHEMICAL & ALLIED PRODUCT MFG	338	2,462	9,211	579	502	1,297	1,708
VA	2018	05	METALS PROCESSING	4,034	0	1,017	1,861	1,592	5,374	469
VA	2018	06	PETROLEUM & RELATED INDUSTRIES	30,284	0	228	315	194	217	642
VA	2018	07	OTHER INDUSTRIAL PROCESSES	14,029	877	10,836	37,553	11,276	18,088	15,636
VA	2018	08	SOLVENT UTILIZATION	0	6	0	314	293	3	127,953
VA	2018	09	STORAGE & TRANSPORT	21	8	15	949	648	0	27,357
VA	2018	10	WASTE DISPOSAL & RECYCLING	24,293	141	2,595	4,694	1,828	2,170	5,821
VA	2018	11	HIGHWAY VEHICLES	1,075,104	10,624	63,342	3,212	1,543	1,043	61,964
VA	2018	12	OFF-HIGHWAY	797,683	61	40,393	6,208	5,891	507	49,052
VA	2018	14	MISCELLANEOUS	27,223	50,279	584	218,141	26,225	158	1,322
	2018 Total			**2,117,096**	**65,192**	**280,549**	**315,051**	**78,754**	**267,867**	**317,368**

State Tier 1 Emission Totals

State	Year	TIER1	TIER 1 NAME	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
WV	2002	01	FUEL COMB. ELEC. UTIL.	10,341	121	230,977	4,573	2,210	516,084	1,180
WV	2002	02	FUEL COMB. INDUSTRIAL	8,685	97	33,825	1,583	1,332	37,111	1,097
WV	2002	03	FUEL COMB. OTHER	29,480	13	15,220	3,814	3,683	3,990	9,275
WV	2002	04	CHEMICAL & ALLIED PRODUCT MFG	50,835	80	1,627	950	831	9,052	5,755
WV	2002	05	METALS PROCESSING	28,837	143	1,570	8,749	7,515	5,619	1,393
WV	2002	06	PETROLEUM & RELATED INDUSTRIES	1	0	1,086	475	475	7,550	2,163
WV	2002	07	OTHER INDUSTRIAL PROCESSES	2,003	56	5,347	18,751	5,567	2,316	1,803
WV	2002	08	SOLVENT UTILIZATION	15	0	18	49	44	0	35,989
WV	2002	09	STORAGE & TRANSPORT	15	0	3	1,952	947	0	12,432
WV	2002	10	WASTE DISPOSAL & RECYCLING	9,395	8	599	4,153	3,731	100	5,098
WV	2002	11	HIGHWAY VEHICLES	533,471	1,908	58,999	1,381	995	2,464	42,174
WV	2002	12	OFF-HIGHWAY	133,113	9	33,239	1,850	1,728	2,112	18,566
WV	2002	14	MISCELLANEOUS	6,897	9,928	149	93,030	10,799	40	349
	2002 Total			**813,089**	**12,364**	**382,659**	**141,310**	**39,857**	**586,436**	**137,275**
WV	2009	01	FUEL COMB. ELEC. UTIL.	11,493	330	85,476	5,657	2,940	268,952	1,361
WV	2009	02	FUEL COMB. INDUSTRIAL	9,529	104	27,109	1,432	1,243	36,964	979
WV	2009	03	FUEL COMB. OTHER	21,558	13	14,229	3,351	3,216	4,047	6,824
WV	2009	04	CHEMICAL & ALLIED PRODUCT MFG	58,271	82	1,804	981	858	10,102	5,426
WV	2009	05	METALS PROCESSING	24,501	116	1,494	2,016	1,507	5,608	831
WV	2009	06	PETROLEUM & RELATED INDUSTRIES	1	0	1,221	535	535	8,495	2,172
WV	2009	07	OTHER INDUSTRIAL PROCESSES	2,288	59	4,995	19,240	5,910	2,570	2,064
WV	2009	08	SOLVENT UTILIZATION	17	0	20	52	47	0	32,199
WV	2009	09	STORAGE & TRANSPORT	17	0	3	1,756	695	0	12,997
WV	2009	10	WASTE DISPOSAL & RECYCLING	9,131	8	583	4,036	3,618	97	4,806
WV	2009	11	HIGHWAY VEHICLES	365,549	2,148	35,635	1,068	684	279	24,843
WV	2009	12	OFF-HIGHWAY	152,862	11	30,133	1,640	1,528	359	18,069
WV	2009	14	MISCELLANEOUS	4,116	10,574	89	93,957	11,002	23	219
	2009 Total			**659,332**	**13,446**	**202,791**	**135,720**	**33,782**	**337,495**	**112,790**
WV	2018	01	FUEL COMB. ELEC. UTIL.	12,397	143	51,474	5,784	3,116	106,199	1,387
WV	2018	02	FUEL COMB. INDUSTRIAL	10,174	111	28,764	1,505	1,308	38,571	1,048
WV	2018	03	FUEL COMB. OTHER	18,891	16	17,254	3,160	3,024	4,065	6,270
WV	2018	04	CHEMICAL & ALLIED PRODUCT MFG	70,252	99	2,183	1,181	1,034	12,196	6,560
WV	2018	05	METALS PROCESSING	28,563	148	1,929	2,491	1,887	6,735	1,087
WV	2018	06	PETROLEUM & RELATED INDUSTRIES	1	0	1,407	616	616	9,786	2,338
WV	2018	07	OTHER INDUSTRIAL PROCESSES	2,756	68	5,949	21,363	6,809	3,101	2,561
WV	2018	08	SOLVENT UTILIZATION	20	0	24	61	55	0	37,886
WV	2018	09	STORAGE & TRANSPORT	19	0	4	2,080	824	0	13,394
WV	2018	10	WASTE DISPOSAL & RECYCLING	9,237	10	592	4,116	3,674	98	5,153
WV	2018	11	HIGHWAY VEHICLES	274,804	2,497	17,247	819	405	253	16,121
WV	2018	12	OFF-HIGHWAY	167,424	13	25,710	1,292	1,198	56	14,086
WV	2018	14	MISCELLANEOUS	5,175	11,453	112	99,667	11,803	29	268
	2018 Total			**599,712**	**14,557**	**152,647**	**144,134**	**35,752**	**181,088**	**108,159**

State Tier 1 Emission Totals

	CO	NH3	NOX	PM10	PM2.5	SO2	VOC
VISTAS 2002 Total	**30,073,168**	**665,818**	**5,429,845**	**3,895,998**	**1,075,343**	**4,879,941**	**5,178,836**
VISTAS 2009 Total	**25,397,398**	**721,736**	**3,790,044**	**4,160,870**	**1,123,548**	**3,465,859**	**4,187,921**
VISTAS 2018 Total	**22,645,302**	**792,678**	**2,722,636**	**4,548,634**	**1,194,728**	**2,169,725**	**3,910,170**

APPENDIX D:

VISTAS TIER 1 EMISSION TOTALS

VISTAS Tier 1 Emission Totals

Year	TIER1	TIER1NAME	CO	NH3	NOX	PM10-PRI	PM25-PRI	SO2	VOC
2002	01	FUEL COMB. ELEC. UTIL.	141,217	1,799	1,523,445	113,917	79,269	3,743,723	12,515
2002	02	FUEL COMB. INDUSTRIAL	371,932	1,204	499,943	85,357	59,735	550,866	32,333
2002	03	FUEL COMB. OTHER	759,534	2,810	122,062	99,532	91,805	114,852	354,375
2002	04	CHEMICAL & ALLIED PRODUCT MFG	131,993	7,093	20,896	11,114	7,982	77,450	63,748
2002	05	METALS PROCESSING	223,705	601	11,801	32,367	27,778	49,143	17,306
2002	06	PETROLEUM & RELATED INDUSTRIES	44,633	355	7,204	2,887	1,863	53,392	33,374
2002	07	OTHER INDUSTRIAL PROCESSES	156,077	7,520	114,474	267,980	97,013	86,736	196,831
2002	08	SOLVENT UTILIZATION	687	331	5,677	3,805	3,284	90	1,288,990
2002	09	STORAGE & TRANSPORT	610	85	1,069	10,968	6,100	230	261,959
2002	10	WASTE DISPOSAL & RECYCLING	546,331	801	28,738	80,336	73,673	6,418	99,497
2002	11	HIGHWAY VEHICLES	19,432,305	73,670	2,187,683	50,338	35,813	89,296	1,890,798
2002	12	OFF-HIGHWAY	6,209,596	477	865,130	72,019	68,302	96,336	813,788
2002	14	MISCELLANEOUS	2,054,548	569,073	41,724	3,065,377	522,726	11,407	113,321
2002 Total			**30,073,168**	**665,818**	**5,429,845**	**3,895,998**	**1,075,343**	**4,879,941**	**5,178,836**
2009	01	FUEL COMB. ELEC. UTIL.	190,535	5,474	789,299	125,750	91,587	2,497,423	14,208
2009	02	FUEL COMB. INDUSTRIAL	391,422	1,305	445,967	74,588	51,491	514,636	32,431
2009	03	FUEL COMB. OTHER	544,289	3,198	123,297	85,410	77,042	112,323	207,146
2009	04	CHEMICAL & ALLIED PRODUCT MFG	140,910	7,611	22,031	11,742	8,394	76,021	54,168
2009	05	METALS PROCESSING	236,473	705	11,763	25,130	21,288	54,337	17,954
2009	06	PETROLEUM & RELATED INDUSTRIES	48,118	399	7,863	3,282	2,124	46,975	25,028
2009	07	OTHER INDUSTRIAL PROCESSES	166,088	7,545	117,625	298,719	111,218	90,420	202,567
2009	08	SOLVENT UTILIZATION	771	360	6,662	4,274	3,679	100	1,256,884
2009	09	STORAGE & TRANSPORT	702	98	1,087	10,729	5,743	160	275,462
2009	10	WASTE DISPOSAL & RECYCLING	770,459	869	36,697	105,449	97,841	7,287	113,473
2009	11	HIGHWAY VEHICLES	13,864,869	87,027	1,414,834	41,861	26,498	10,962	1,217,185
2009	12	OFF-HIGHWAY	6,827,857	530	767,707	61,528	58,279	42,845	649,786
2009	14	MISCELLANEOUS	2,214,906	606,617	45,212	3,312,407	568,364	12,370	121,629
2009 Total			**25,397,398**	**721,736**	**3,790,044**	**4,160,870**	**1,123,548**	**3,465,859**	**4,187,921**
2018	01	FUEL COMB. ELEC. UTIL.	262,414	9,306	568,158	152,642	118,959	1,169,110	17,090
2018	02	FUEL COMB. INDUSTRIAL	416,721	1,383	470,326	80,011	55,648	513,072	34,720
2018	03	FUEL COMB. OTHER	453,482	3,358	136,431	78,032	69,854	116,672	149,363
2018	04	CHEMICAL & ALLIED PRODUCT MFG	173,857	9,023	26,564	14,454	10,360	94,010	67,414
2018	05	METALS PROCESSING	279,850	926	14,871	31,221	26,572	66,150	23,089
2018	06	PETROLEUM & RELATED INDUSTRIES	53,392	460	8,891	3,845	2,490	43,055	27,283
2018	07	OTHER INDUSTRIAL PROCESSES	189,922	8,793	136,722	348,119	130,778	100,824	237,601
2018	08	SOLVENT UTILIZATION	936	404	8,480	5,354	4,601	119	1,515,005
2018	09	STORAGE & TRANSPORT	855	119	1,258	13,540	7,283	192	290,267
2018	10	WASTE DISPOSAL & RECYCLING	821,737	1,068	40,324	114,690	105,745	8,544	125,406
2018	11	HIGHWAY VEHICLES	10,312,627	103,394	663,796	33,426	16,403	10,281	752,732
2018	12	OFF-HIGHWAY	7,438,312	612	601,040	48,648	45,927	35,166	546,062
2018	14	MISCELLANEOUS	2,241,196	653,831	45,776	3,624,653	600,107	12,532	124,137
2018 Total			**22,645,302**	**792,678**	**2,722,636**	**4,548,634**	**1,194,728**	**2,169,725**	**3,910,170**

APPENDIX E:

AIRCRAFT PM EXCERPT FROM 2001 TUCSON REPORT

Final Report

EMISSIONS INVENTORIES FOR THE TUCSON AIR PLANNING AREA

VOLUME I. STUDY DESCRIPTION AND RESULTS

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ACKNOWLEDGEMENTS

The authors extend their appreciation to the many individuals that contributed to this study. Particular thanks go to the staff of the Pima Association of Governments. Darcy Anderson was instrumental in providing definition at the outset of the study. Lee Comrie and Natalie Barnes provided considerable assistance with the emissions surveys, made many thoughtful suggestions and contributions throughout the study, and provided helpful comments on the draft final report. Kwame Agyare, Wayne Byrd and Bill Maxwell of the Pima County Department of Environmental Quality offered valuable assistance in providing socioeconomic and PDEQ permit data and in sharing their knowledge of emissions sources in the Tucson Air Planning Area. Dan Catlin of the Arizona Department of Environmental Quality provided insightful comments during the course of the study and reviewed the draft final report.

Many individuals in the Tucson area participated in the annual and day-specific emissions surveys conducted as part of this study. The information they provided is sincerely appreciated.

We also wish to acknowledge Patricia El-Gasseir and Helen Fugate of Rumla, Inc. for their dedicated efforts in building the facilities database.

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ABBREVIATIONS AND ACRONYMS

ADEQ	Arizona Department of Environmental Quality
ADWM	Arizona Department of Weights and Measures
ALD2	High Molecular Weight Aldehydes (RCHO, R≠H)
AML	Arc Macro Language
AQM	Air Quality Model
APU	Aircraft Power Unit
ARB	California Air Resources Board
ASC	Area Source Category Code
AT	Air Taxi
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CSF	Chemical Speciation Factor
DM	Davis-Monthan Air Force Base
DOT	Department of Transportation
EDMS	Emissions Dispersion Modeling System
EEA	Energy & Environmental Analysis, Inc.
EIPP	Emission Inventory Preparation Plan
EPA	The U.S. Environmental Protection Agency
ETH	Ethene (CH_2═CH_2)
FAA	Federal Aviation Administration
FAEED	FAA Aircraft Engine Emission Database
FIPS	Federal Information Processing System
FIRE	EPA's Factor Information REtrieval Data System
FORM	Formaldehyde (CH_2═O)
GA	General Aviation
GIS	Geographical Information System
GSE	Ground Support Equipment
ICAO	International Civil Aviation Organization

ABBREVIATIONS AND ACRONYMS

ISOP	Isoprene
LPG	Liquid Petroleum Gas
LTO	Landing and TakeOff
NAD27	North American Datum - 1927
NCDC	National Climatic Data Center
NEI	US EPA National Emission Inventory
NEVES	Nonroad Engine and Vehicle Emission Study
NG	Natural Gas
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
OLE	Olefinic Carbon Bond (C═C)
ORNL	Oak Ridge National Laboratory
PAG	Pima Association of Governments
PAR	Paraffinic Carbon Bond (C—C)
PDEQ	Pima County Department of Environmental Quality
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 microns
PM_{10}	Particulate Matter less than 10 microns
RASP	Regional Aviation System Plan
RVP	Reid Vapor Pressure
SAF	Spatial Allocation Factor
SCC	Source Category Code
SCF	Standard Cubic Foot
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_X	Oxides of Sulfur
TAF	Temporal Allocation Factor

ABBREVIATIONS AND ACRONYMS

TAPA	Tucson Air Planning Area
TAZ	Transportation Analysis Zone
THC	Total Hydrocarbon
TIA	Tucson International Airport
TIM	Time-In-Mode
TOL	Tolulene (C_6H_5—CH_3)
TTN	EPA Technology Transfer Network
UAM	Urban Airshed Model
UP	Union Pacific Railroad
VOC	Volatile Organic Compounds as defined by the 1990 Clean Air Act Amendments
XYL	Xylene (C_6H_6—$(CH_3)_2$)

(Prior material unrelated to VISTAS modeling is intentionally omitted)

While emission rates for HC, CO, and NO_x are routinely measured from (new) commercial air carrier engines under the emissions certification component of International Civil Aviation Organization (ICAO) regulations, measurement of PM emissions is not required. As a result, almost all aircraft engine PM emission rate data have been collected under special studies. Currently, such data exists for only about 20 aircraft engines, with a considerable portion of these data collected by the U.S. Air Force for military aircraft engines. While emission factors for these engines are included in the AP-42 database upon which the FAEED and EDMS emission inventory models were developed, they have not been included in either model due to their limited applicability. To date, it has been standard EPA practice not to estimate PM emissions for aircraft engines. However, since the emissions models maintain a placekeeper for PM emission rates and include PM emission estimates for GSE, it can appear to the uninformed user that aircraft PM emission rates are zero. As a result, aircraft are often incorrectly considered to be insignificant PM sources even though those engines tested for PM have demonstrated significant emission rates. This policy of exclusion by omission is not appropriate in developing an accurate modeling inventory, even in the absence of a large emissions database. While a precise emissions estimate cannot be made with available data, it is clear that a zero emission rate is far from accurate.

As an alternative for this study, measured emissions data for aircraft engines that have been tested for PM were statistically analyzed to determine whether or not a relationship to other measured emissions parameters could be established. Intuitively, it was hoped that an inverse relationship with NO_x might be demonstrated, as such a relationship is theoretically attractive. While the level of sophistication of the statistical analysis is constrained by the quantity of data available, simple direct and indirect linear relationships can be examined. Because data are not available for each test engine in each of the four LTO cycle modes and because relationships might be expected to vary by operating mode (due to significant changes in engine and combustion efficiency), all statistical analysis was performed for each operating mode individually.

Statistically significant relationships were found for the direct linear analysis for three of the four LTO cycle modes. Significant in this context means that coefficient t-statistics for one or more of the other measured pollutants (HC, CO, or NO_x) indicated a direct relationship with measured PM (at a confidence level exceeding 95 percent). In all cases, correlation coefficients were poor (as expected), suggesting a high level of variability and poor predictability of PM emissions for any given engine. Nevertheless, statistics were unbiased and should provide an accurate mechanism to initially assess PM emissions on a aggregate basis (i.e., over a range of aircraft engine models such as those associated with an analysis for an entire set of airport operations). Only at idle was no significant relation found, which is not surprising given relative engine inefficiency in this mode.

The indirect linear analysis revealed a consistent and significant inverse relationship between PM and NO_x based on calculated t-statistics. Correlation coefficients continue to be poor, but t-statistics are generally improved over those of the direct linear analysis (all developed inverse relations, including idle, were significant at the 99 percent confidence level). In selecting the most appropriate relationship for estimation of PM emission rates for non-tested aircraft engines, the statistical analysis that produced the best combination of a significant t-statistic, a relatively low root mean square error, and an intuitive engineering basis was identified. This was the inverse NO_x relationship for the takeoff (i.e., full throttle) mode of operation. Figure 4-1 illustrates the selected statistical relationship.

With this relationship established, PM emission rate data for the other aircraft operating modes (i.e., the approach, taxi, and climbout modes) was statistically analyzed against observed PM emission rate data for the takeoff mode. Statistically significant relations were developed for all three modes. Table 4-23 presents the coefficients developed for these PM-to-PM regressions as well as the statistics for the PM-to-NO_x regression developed for the takeoff mode. These four relations were used to develop a set of fleetwide PM emission factors based on measured takeoff NO_x emission rates. These emission factors were then input into the EEA aircraft emissions model and used to generate PM emission estimates for TIA aircraft operations.

FIGURE 4-1. Relationship Used to Estimate Aircraft PM Emission Rates

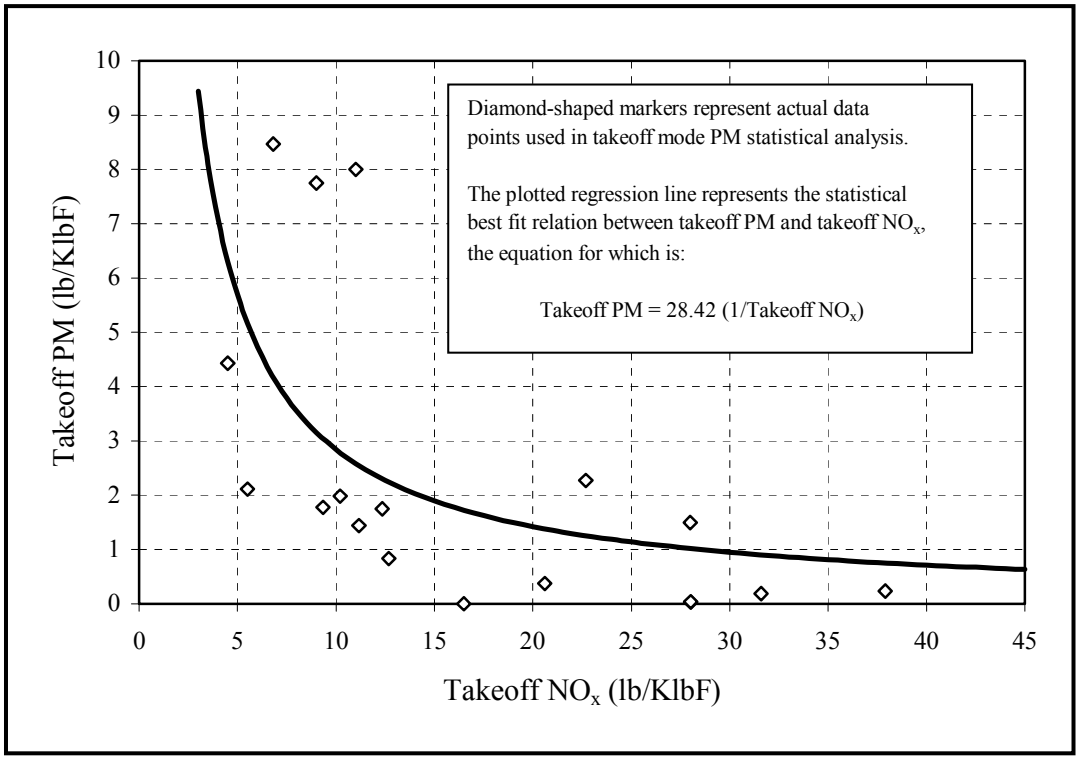


TABLE 4-23. Statistics for Aircraft and APU PM Relations

Statistical Parameter	Takeoff PM	Climbout PM	Approach PM	Taxi PM
Predictive Parameter	1/Takeoff NO_x	Takeoff PM	Takeoff PM	Takeoff PM
Coefficient	28.42	1.42	1.53	3.10
Coefficient t-statistic	5.1	11.8	14.9	5.7
Correlation Coefficient	0.30	0.84	0.91	0.56
F-statistic	7.4	86.1	135.7	21.9
Number of Observations	18	17	15	18

(Subsequent material unrelated to VISTAS modeling is intentionally omitted)

APPENDIX F:

COMPARISON OF BASE F AND BASE G ON-ROAD MOBILE EMISSIONS

Base G Onroad Mobile Emissions (Annual Tons)

	VOC			NOx			CO			SO2			PM-10			PM-2.5			NH3		
FIPSST	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018
AL	125,768	76,065	44,503	156,460	100,693	42,622	1,303,508	902,469	594,725	6,827	802	654	3,861	3,136	2,193	2,768	2,010	1,085	5,530	6,298	6,630
FL	520,757	336,707	199,050	460,503	312,321	136,040	4,493,820	3,308,863	2,263,190	20,687	2,584	2,302	11,148	9,801	7,516	7,779	6,104	3,671	17,922	21,549	23,778
GA	279,975	192,773	99,464	304,309	207,024	92,113	2,699,650	1,956,263	1,303,529	12,043	1,568	1,325	7,165	6,005	4,406	5,110	3,797	2,166	10,436	12,554	13,511
KY	102,362	73,142	42,810	154,634	100,025	46,993	1,214,191	950,912	711,211	6,238	751	694	3,682	2,944	2,348	2,667	1,899	1,158	5,003	5,737	7,095
MS	86,811	51,600	28,699	110,672	69,952	27,620	853,774	602,257	394,247	4,566	532	401	2,828	2,250	1,479	2,089	1,491	746	3,549	3,995	4,147
NC	260,895	166,844	91,720	323,606	199,281	79,433	2,839,283	1,966,195	1,207,391	12,286	1,487	1,346	6,505	5,510	3,994	4,571	3,453	1,931	9,601	11,702	12,776
SC	114,861	71,781	41,866	138,940	91,471	39,348	1,226,555	878,825	588,536	5,909	713	584	3,414	2,831	1,986	2,473	1,834	988	4,646	5,466	5,878
TN	177,943	114,032	61,339	235,869	150,179	62,446	1,893,704	1,320,562	863,682	9,127	1,065	862	5,312	4,160	2,813	3,904	2,720	1,405	6,556	7,702	8,196
VA	157,989	95,694	55,992	219,835	132,699	57,192	2,136,288	1,435,359	954,463	8,196	1,067	949	4,499	3,706	2,922	3,067	2,216	1,404	7,770	8,990	9,653
WV	41,703	24,570	14,652	58,340	35,234	15,530	526,841	360,865	243,683	2,438	276	231	1,366	1,057	747	984	676	369	1,889	2,126	2,268
VISTAS	**1,869,063**	**1,203,208**	**680,096**	**2,163,168**	**1,398,879**	**599,336**	**19,187,613**	**13,682,570**	**9,124,656**	**88,316**	**10,844**	**9,348**	**49,780**	**41,400**	**30,403**	**35,411**	**26,200**	**14,922**	**72,902**	**86,118**	**93,932**

Base F Onroad Mobile (Annual Tons)

	VOC			NOx			CO			SO2			PM-10			PM-2.5			NH3		
FIPSST	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018
AL	118,978	73,137	47,151	157,626	101,299	46,598	1,300,754	934,442	675,902	6,898	637	720	3,905	3,195	2,488	2,799	2,053	1,262	5,586	6,362	7,296
FL	438,761	293,423	192,096	402,099	284,737	134,465	4,022,000	3,090,443	2,306,759	18,802	1,911	2,289	10,185	9,027	7,691	7,126	5,653	3,848	16,183	19,553	23,595
GA	265,972	187,102	104,678	306,998	208,568	100,707	2,712,473	2,044,169	1,474,029	12,182	1,256	1,458	7,252	6,116	4,995	5,169	3,877	2,517	10,545	12,685	14,870
KY	96,202	63,210	38,814	154,093	97,731	43,014	1,195,656	932,296	669,891	5,988	587	651	3,728	3,008	2,283	2,699	1,946	1,160	5,055	5,807	6,584
MS	81,701	49,986	30,337	110,242	69,949	29,829	849,049	624,575	445,150	4,614	398	441	2,863	2,296	1,688	2,114	1,525	876	3,585	4,035	4,565
NC	272,594	167,894	87,718	290,873	207,670	83,399	2,677,118	2,192,253	1,238,802	12,482	1,314	1,323	6,733	5,874	4,299	4,754	3,651	2,158	9,711	12,663	13,077
SC	107,236	69,026	44,121	139,403	91,832	42,641	1,220,825	921,308	663,597	5,972	558	643	3,454	2,884	2,258	2,502	1,874	1,154	4,694	5,522	6,472
TN	168,389	109,716	63,916	233,324	147,591	66,879	1,881,893	1,359,880	961,929	9,202	833	944	5,349	4,247	3,199	3,927	2,788	1,643	6,629	7,753	8,962
VA	143,969	91,230	59,737	222,830	133,039	64,079	1,996,287	1,483,125	1,091,546	7,234	902	1,059	4,546	3,768	3,343	3,097	2,258	1,641	7,852	9,084	10,757
WV	39,581	23,914	15,375	60,335	36,000	16,940	533,258	379,272	273,900	2,495	228	255	1,399	1,099	844	1,005	705	428	1,938	2,188	2,484
VISTAS	**1,733,382**	**1,128,638**	**683,942**	**2,077,822**	**1,378,416**	**628,551**	**18,389,312**	**13,961,764**	**9,801,505**	**85,868**	**8,622**	**9,783**	**49,414**	**41,513**	**33,086**	**35,191**	**26,330**	**16,687**	**71,778**	**85,652**	**98,664**

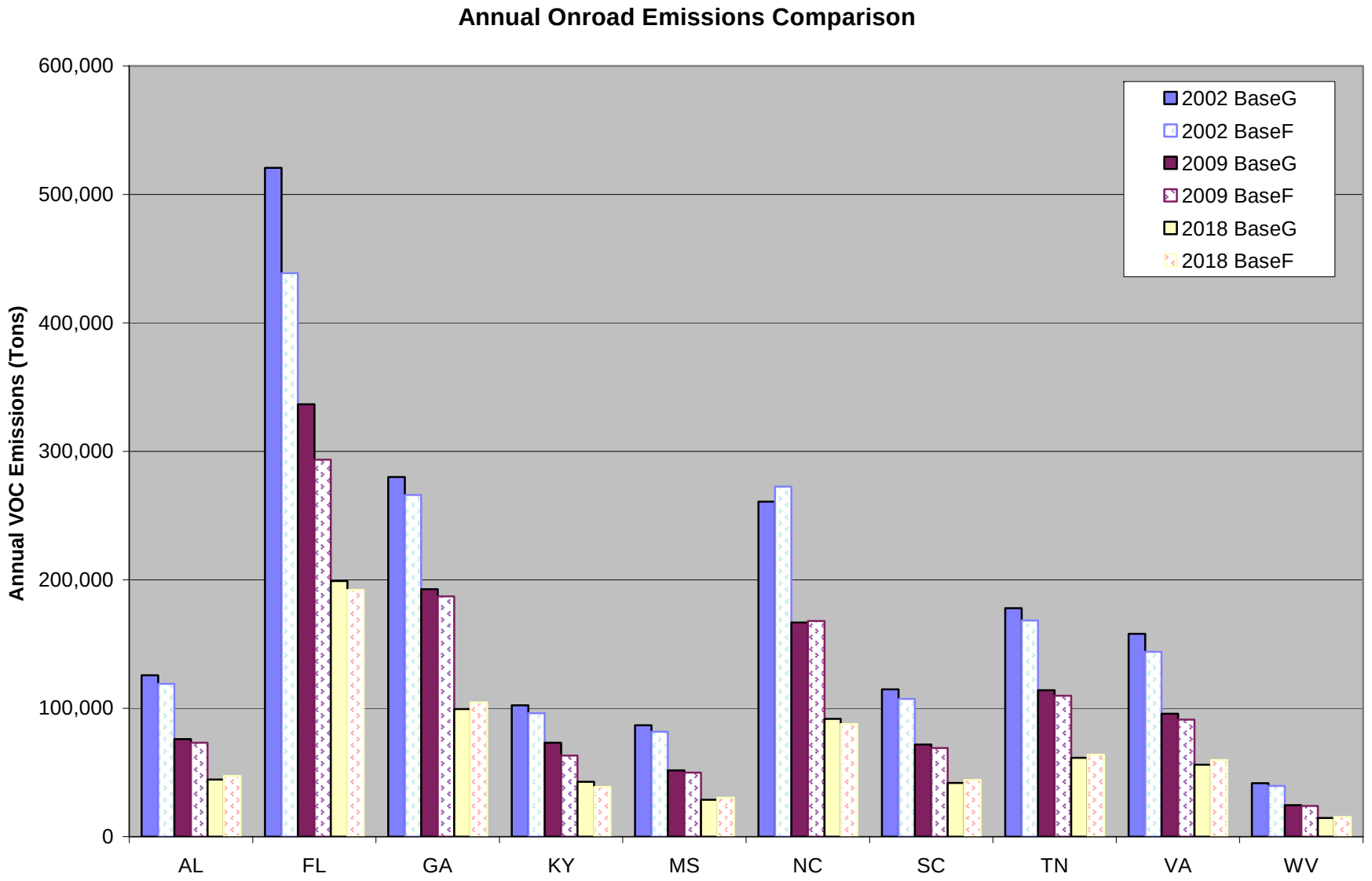
Emissions Change (Base G - Base F, Annual Tons) -- Positive Value Indicates Increase from Base F

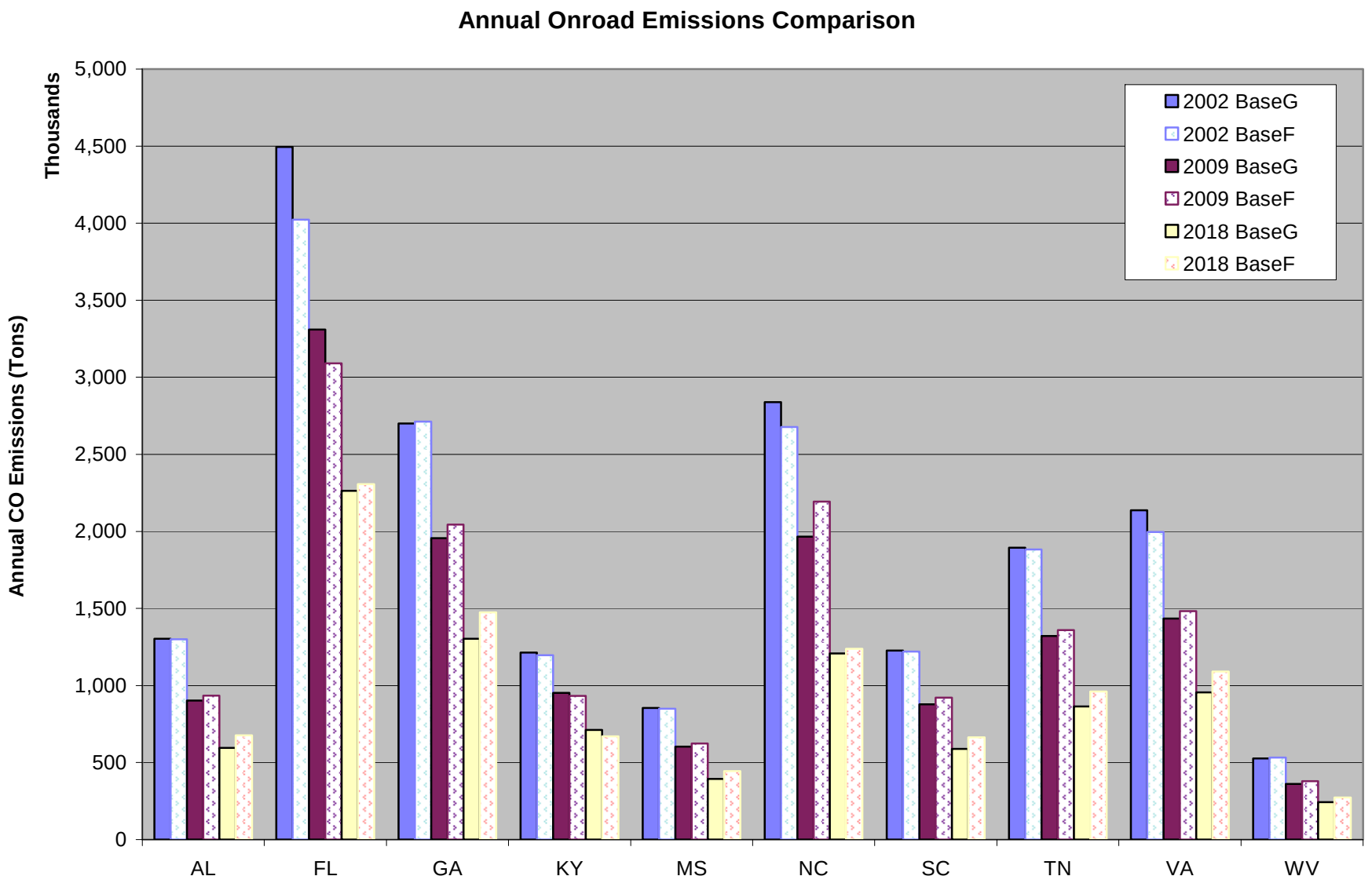
	VOC			NOx			CO			SO2			PM-10			PM-2.5			NH3		
FIPSST	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018
AL	6,789	2,928	-2,647	-1,166	-606	-3,977	2,754	-31,973	-81,178	-71	165	-66	-45	-58	-295	-31	-43	-178	-56	-63	-666
FL	81,997	43,284	6,955	58,404	27,584	1,575	471,820	218,420	-43,569	1,885	672	14	963	774	-175	653	451	-177	1,738	1,996	183
GA	14,003	5,671	-5,214	-2,689	-1,544	-8,594	-12,823	-87,906	-170,500	-139	312	-133	-86	-111	-589	-59	-80	-352	-109	-131	-1,359
KY	6,160	9,933	3,996	541	2,294	3,979	18,534	18,615	41,319	250	164	43	-46	-65	65	-32	-47	-2	-52	-70	512
MS	5,110	1,613	-1,638	430	3	-2,209	4,724	-22,319	-50,903	-48	134	-41	-35	-46	-209	-25	-34	-130	-35	-40	-419
NC	-11,699	-1,049	4,001	32,734	-8,389	-3,966	162,165	-226,057	-31,411	-196	174	23	-228	-364	-304	-183	-198	-226	-111	-961	-302
SC	7,625	2,755	-2,255	-462	-362	-3,293	5,731	-42,483	-75,061	-63	156	-59	-40	-53	-272	-29	-40	-166	-48	-56	-594
TN	9,554	4,316	-2,577	2,545	2,589	-4,433	11,811	-39,318	-98,246	-75	232	-82	-37	-87	-385	-22	-68	-238	-73	-52	-766
VA	14,020	4,464	-3,744	-2,995	-340	-6,887	140,001	-47,766	-137,084	962	165	-110	-47	-62	-420	-30	-42	-237	-83	-94	-1,104
WV	2,122	656	-723	-1,995	-766	-1,410	-6,416	-18,407	-30,217	-57	49	-24	-32	-42	-97	-22	-29	-59	-49	-62	-217
VISTAS	**135,680**	**74,570**	**-3,846**	**85,346**	**20,462**	**-29,215**	**798,301**	**-279,194**	**-676,850**	**2,448**	**2,222**	**-435**	**367**	**-114**	**-2,683**	**219**	**-130**	**-1,764**	**1,123**	**466**	**-4,732**

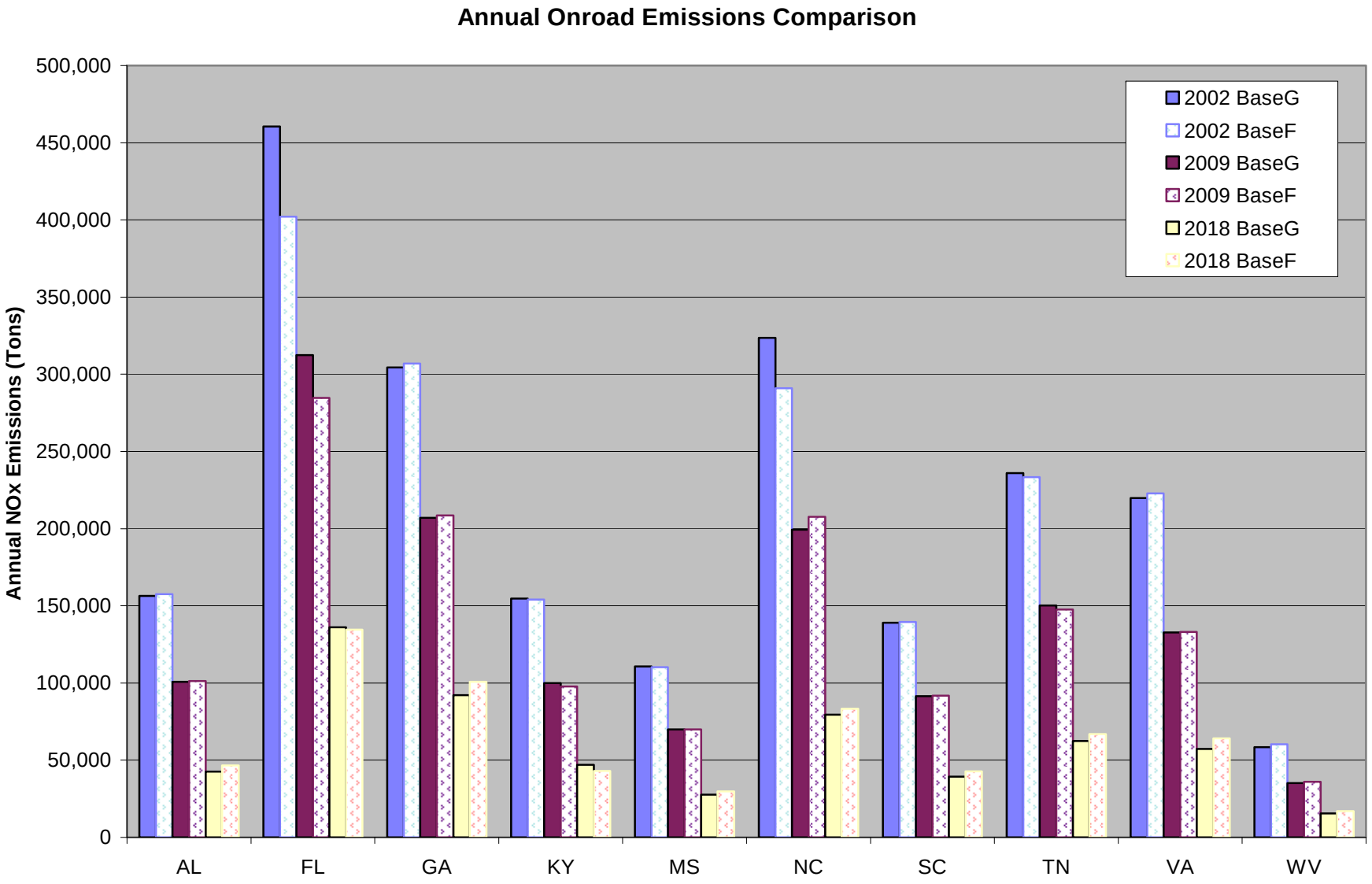
Emissions Change (Base G - Base F/Base F, Annual %) -- Positive Value Indicates Increase from Base F

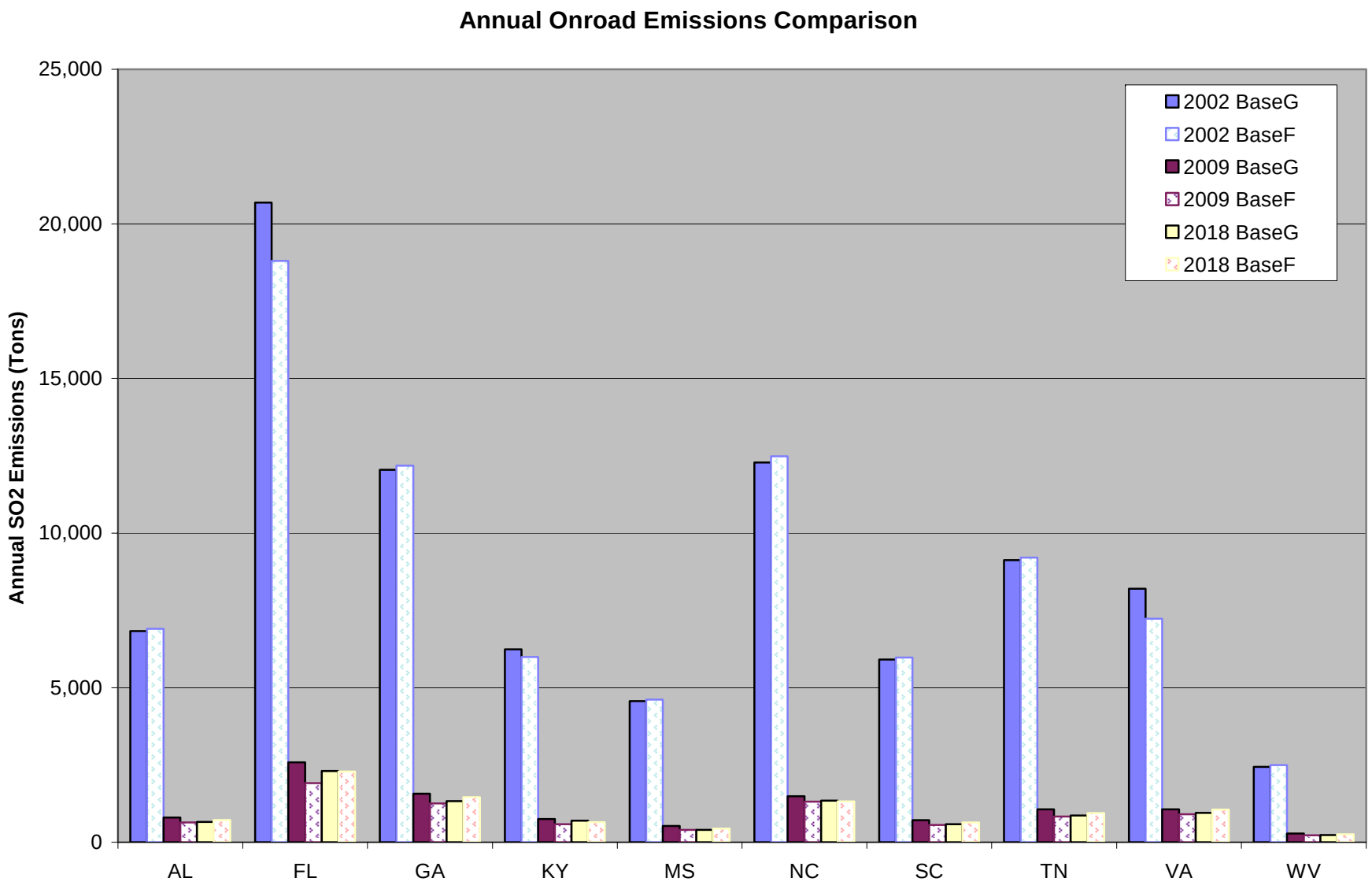
	VOC			NOx			CO			SO2			PM-10			PM-2.5			NH3		
FIPSST	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018	2002	2009	2018
AL	6%	4%	-6%	-1%	-1%	-9%	0%	-3%	-12%	-1%	26%	-9%	-1%	-2%	-12%	-1%	-2%	-14%	-1%	-1%	-9%
FL	19%	15%	4%	15%	10%	1%	12%	7%	-2%	10%	35%	1%	9%	9%	-2%	9%	8%	-5%	11%	10%	1%
GA	5%	3%	-5%	-1%	-1%	-9%	0%	-4%	-12%	-1%	25%	-9%	-1%	-2%	-12%	-1%	-2%	-14%	-1%	-1%	-9%
KY	6%	16%	10%	0%	2%	9%	2%	2%	6%	4%	28%	7%	-1%	-2%	3%	-1%	-2%	0%	-1%	-1%	8%
MS	6%	3%	-5%	0%	0%	-7%	1%	-4%	-11%	-1%	34%	-9%	-1%	-2%	-12%	-1%	-2%	-15%	-1%	-1%	-9%
NC	-4%	-1%	5%	11%	-4%	-5%	6%	-10%	-3%	-2%	13%	2%	-3%	-6%	-7%	-4%	-5%	-10%	-1%	-8%	-2%
SC	7%	4%	-5%	0%	0%	-8%	0%	-5%	-11%	-1%	28%	-9%	-1%	-2%	-12%	-1%	-2%	-14%	-1%	-1%	-9%
TN	6%	4%	-4%	1%	2%	-7%	1%	-3%	-10%	-1%	28%	-9%	-1%	-2%	-12%	-1%	-2%	-14%	-1%	-1%	-9%
VA	10%	5%	-6%	-1%	0%	-11%	7%	-3%	-13%	13%	18%	-10%	-1%	-2%	-13%	-1%	-2%	-14%	-1%	-1%	-10%
WV	5%	3%	-5%	-3%	-2%	-8%	-1%	-5%	-11%	-2%	21%	-9%	-2%	-4%	-12%	-2%	-4%	-14%	-3%	-3%	-9%
VISTAS	**8%**	**7%**	**-1%**	**4%**	**1%**	**-5%**	**4%**	**-2%**	**-7%**	**3%**	**26%**	**-4%**	**1%**	**0%**	**-8%**	**1%**	**0%**	**-11%**	**2%**	**1%**	**-5%**

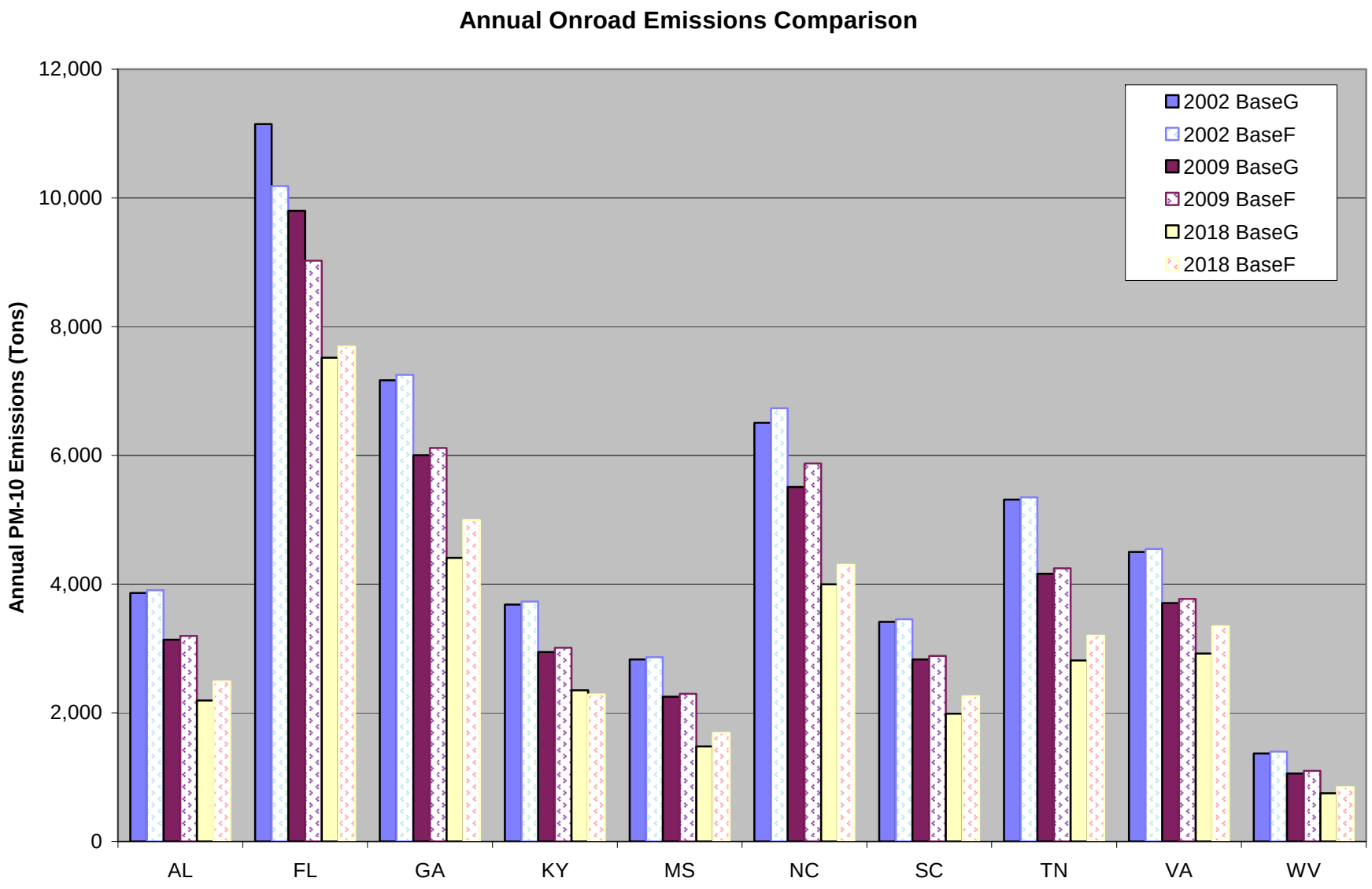
Note: Base G is equivalent to the Best and Final inventory for onroad mobile sources.

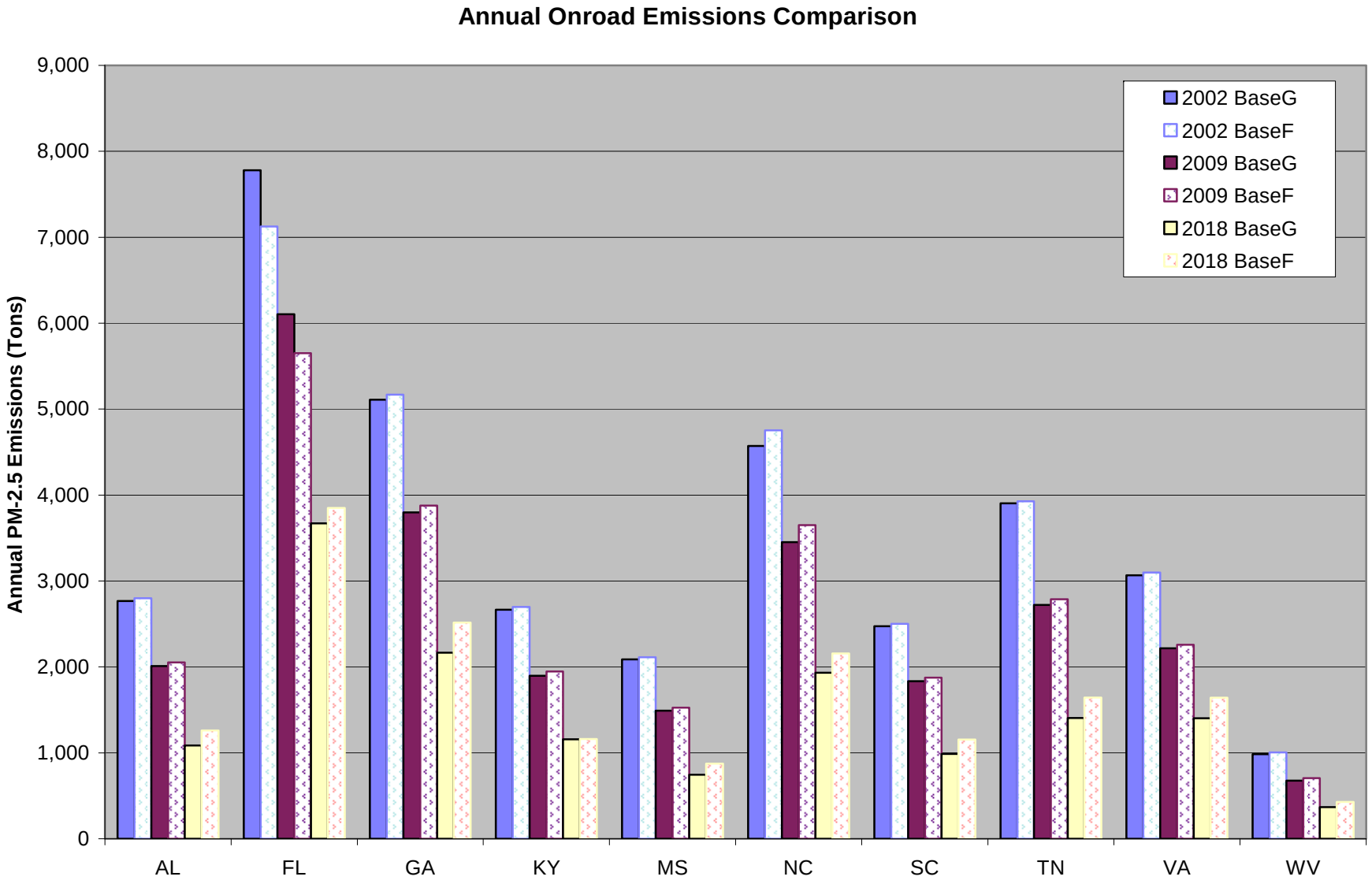

Annual Onroad Emissions Comparison
Annual VOC Emissions (Tons)
600,000
500,000
400,000
300,000
200,000
100,000
0
2002 BaseG
2002 BaseF
2009 BaseG
2009 BaseF
2018 BaseG
2018 BaseF
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV

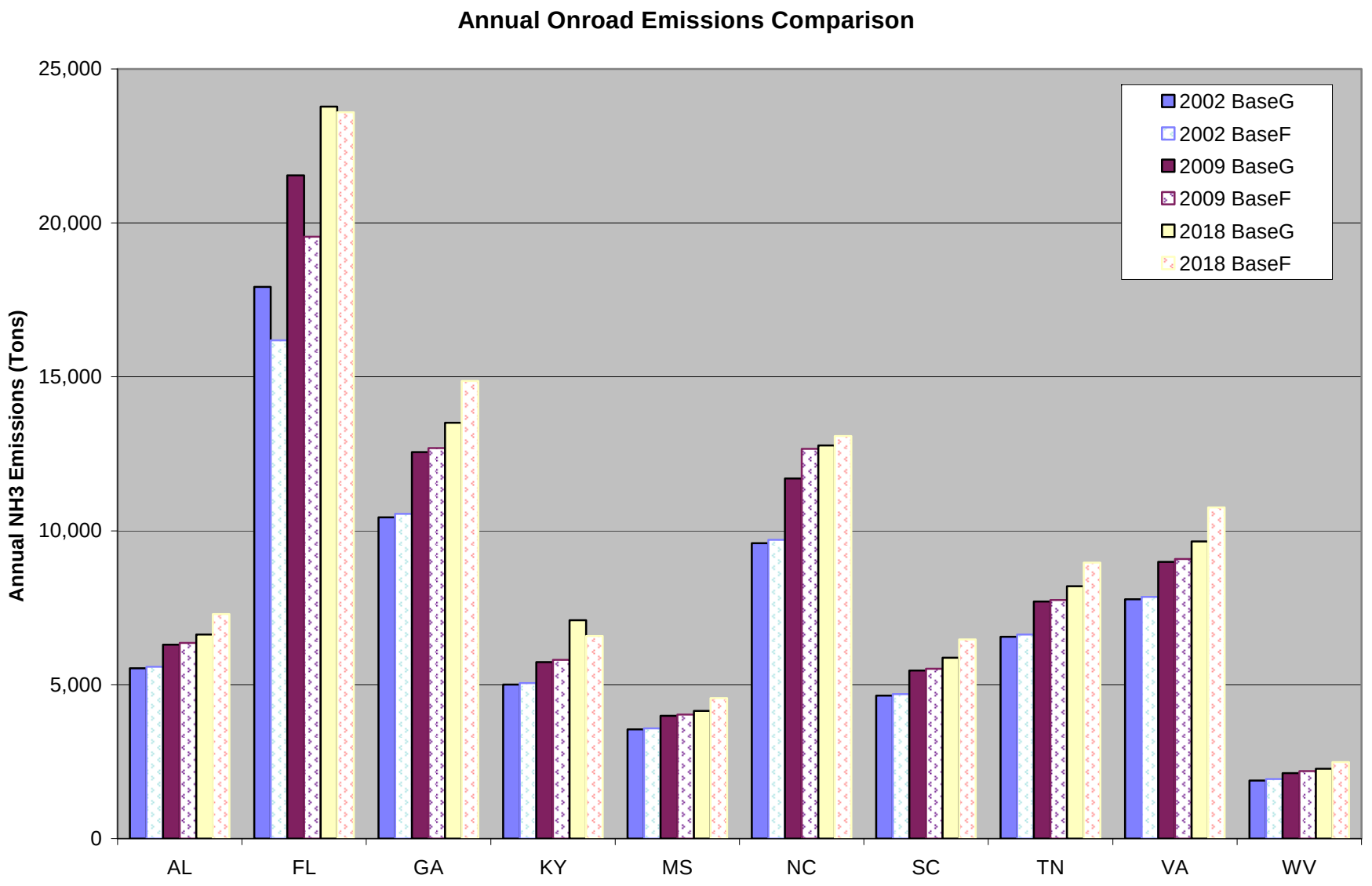

Annual Onroad Emissions Comparison
Thousands
Annual CO Emissions (Tons)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2002 BaseG
2002 BaseF
2009 BaseG
2009 BaseF
2018 BaseG
2018 BaseF
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV


Annual Onroad Emissions Comparison
Annual NOx Emissions (Tons)
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV
2002 BaseG
2002 BaseF
2009 BaseG
2009 BaseF
2018 BaseG
2018 BaseF


Annual Onroad Emissions Comparison
Annual SO2 Emissions (Tons)
25,000
20,000
15,000
10,000
5,000
0
2002 BaseG
2002 BaseF
2009 BaseG
2009 BaseF
2018 BaseG
2018 BaseF
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV


Annual Onroad Emissions Comparison
Annual PM-10 Emissions (Tons)
12,000
10,000
8,000
6,000
4,000
2,000
0
2002 BaseG
2002 BaseF
2009 BaseG
2009 BaseF
2018 BaseG
2018 BaseF
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV


Annual Onroad Emissions Comparison
Annual PM-2.5 Emissions (Tons)
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2002 BaseG
2002 BaseF
2009 BaseG
2009 BaseF
2018 BaseG
2018 BaseF
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV


Annual Onroad Emissions Comparison
Annual NH3 Emissions (Tons)
25,000
20,000
15,000
10,000
5,000
0
2002 BaseG
2002 BaseF
2009 BaseG
2009 BaseF
2018 BaseG
2018 BaseF
AL
FL
GA
KY
MS
NC
SC
TN
VA
WV

APPENDIX G:

CONVERSION OF MRPO BaseM POINT SOURCE DATA TO SMOKE INPUT FORMAT

Atmospheric Sciences Group

ALPINE GEOPHYSICS

MEMORANDUM

To: Pat Brewer, VISTAS
From: Gregory Stella, Alpine Geophysics, LLC
Re: Conversion of MRPO BaseM Point Source Data to SMOKE Input Format
Date: 13 February 2008

The Midwest Regional Planning Organization (MRPO) periodically produces a five State emission inventory for Illinois, Indiana, Michigan, Wisconsin, and Ohio. These data are used as the basis for various MRPO modeling and regulatory analyses. These data are prepared with the help of each State's emission inventory divisions and are felt to be the most representative account for emissions activities for those States at any one time.

The most recent version prepared and distributed by MRPO is currently called BaseM. Associated with this 2005 base year inventory release is a set of growth and control factors that are used to additionally simulate future year conditions under "On-The-Books" (base case or known control programs requirements to be implemented in future years) or incremental control situations to test sensitivity or strategies which would be implemented in whole or in part during the same future years.

The purpose of this document is to detail the technical steps that were made as part of the conversion of the MRPO BaseM point sources files (electric generating unit [EGU] and non-EGU) into IDA format for ASIP PM-2.5 CAMx modeling of the future year 2009. Because of the timing and complications relative to converting multiple and various emission files for all source types, it was determined that only point source emissions would be converted for processing at this time.

Data Sources and Description

A series of data files and associated documentation was obtained from MRPO staff in 2007. These files were the input data sets for base year 2005 and growth and control factors related to MRPO's BaseM and Round 5 inventories[6]. Because of the emission processing tools that MRPO currently executes for its analyses, these files are in formats that are not read by the SMOKE emissions processor currently in use by VISTAS/ASIP modelers (contract teams and participating states). Alpine Geophysics, under the Emissions Inventory Technical Advisor contract, was asked to obtain and convert these data into the formats that could be used by these modeling agencies.

Through additional contact with MRPO staff, the base year 2005 non-EGU point source files and associated growth and control factors necessary to forecast the data to 2009 base case conditions were identified and extracted from the originally provided data. EGU sources were identified to be already prepared for the future year (2010 substituted for 2009) and were based on recent IPM 3.0 model runs with incremental adjustment made by MRPO states to best reflect expected emission controls and operating conditions. The "will do" simulation series for EGUs was identified as "egu5b_2010."

The main purpose of the SMOKE conversion task was to prepare five state emission inventories provided in National Input Format (NIF) format into the IDA format required by the SMOKE model for the criteria pollutants VOC, NOx, CO, SO2, PM-10, PM-2.5, and NH3. Annual emissions were taken directly from the NIF structured inventories with no alternate temporal calculations performed (e.g., estimate seasonal emissions from annual or annual from seasonal). The temporal allocation module of the SMOKE emissions processor was intended to be used to further define temporal distribution of these emissions.

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[6] http://www.ladco.org/tech/emis/r5/round5_reports.htm

No quality assurance (QA) related to the reported values in the MRPO was conducted (e.g., it was assumed that reported emission levels were correct) and therefore the QA focus of these tasks was to maintain the integrity of the mass files in the conversion to IDA.

Each set of NIF structured data had a unique set of relational tables necessary to maintain the information required in each source sector based on its reporting requirements. Alpine had previously developed scripts to read the information from each of these relational data sets and convert them to the IDA structures required by this task. Prior to and after each major source sector was converted from NIF to IDA, we developed a list of emission summary reports to check that the emissions input into the conversion process were the same as output into the IDA formatted files.

Non-EGU Point Source Conversion

Non-EGU point source emissions from 2005 BaseM were converted to future year 2009 IDA format using the annual emission records directly from the NIF structured data sets and associated SCC growth factors and unit, facility, county, state, or nationally applied controls[7]. These controls were applied in a hierarchical fashion starting with the most defined (unit-segment-pollutant level) through least defined (national-SCC-pollutant) and when a match was found during the implementation, no additional controls were sought or applied to that emission record. In other words, if a match were found at the unit-segment level of control, no additional controls were applied to that segment/pollutant combination again in the forecast process. This prevented multiple control programs from being implemented when the intent of the originally provided control files were to assign a single applicable reduction.

The Round 5 factors for point sources provided by MRPO were in the RPO Data Exchange Format (RPODx) and had growth and control factors available at the State, county, plant, unit, segment, stack, and SCC level of detail. In order to apply these factors in a fashion consistent with that of the MRPO utilized processing system and duplicative of how MRPO would have generated its BaseM forecasts, a hierarchical approach was utilized to match and assign growth and control values.

Growth Factor Application

Using the 2005 EM table from the BaseM inventory files in NIF format, we first selected each emissions record for forecasting. In this conversion case, these EM records were limited to those emissions identified as annual using the NIF coding convention. As noted in the limitations section below, there oftentimes were emissions provided by MRPO in a summer season convention.

We next selected the base year for application as the RPODx for growth rates allows for the flexibility of input growth factors for multiple base year inventories. In this assignment, the base year was always 2005, as that was the base year provided by MRPO and the future year was 2009, as selected by ASIP.

The next step was to determine the growth basis for each individual emission record of the file. This “growth basis” is the key with which the growth factor is associated. For point sources, this key is based on a combination of FIPS, SCC, and pollutant codes. Multiple keys are calculated for each individual emission record and that key with the highest resolution of matching to the growth factor file using the hierarchy identified in Table 1 below is the one chosen to assign a growth rate to the base year emissions.

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7 http://www.ladco.org/tech/emis/r5/reports/LADCO%202005%20Base%20Yr%20Growth%20and%20Controls%20Report_Final.pdf

Table 1. Point Source Growth Factor Application Hierarchy.

Order	Key or "Growth/Control Basis"
1	state/county code, 10-digit SCC, pollutant
2	state/county code, 10-digit SCC
3	state code, 10-digit SCC, pollutant
4	state code, 10-digit SCC
5	state/county code, pollutant
6	state/county code
7	state code, pollutant
8	state code
9	10-digit SCC, pollutant
10	10-digit SCC
11	Pollutant

Using the hierarchical application, growth basis, and dates (base year and alternate year), we matched each emission record to the growth table to obtain a growth factor. The factors are defined in the growth table as a multiplier for the base year period that calculates the alternate year of interest. In other words, multiplying the base year emissions value by the growth factor provides you with the emissions for the alternate year of interest.

When no match from any of the hierarchical keys was identified, a growth rate of 1.00 (no growth) was assigned. This maintained the 2005 emission level in the future year inventory.

Control Factor Application

Similar to the process identified above for the assignment and application of growth factors, the control factor assignment was based on a hierarchical key, this time, however, using FIPS, plantid, pointid, stackid, segment, SCC, and pollutant codes applied in a parallel process to the growth factor assignment.

Using the 2005 EM table from the BaseM inventory files in NIF format, we selected each annual emissions record for forecasting. We next selected the base year for application, and again, the base year was always 2005, as that was the base year provided by MRPO.

Once the base year was identified, we determined the alternate year for our forecast. Depending on the specific year used in each conversion, growth rates were limited to those with a base year of 2005 and a future year *less than or equal to* that of our forecast. This variation in method is intended to allow us to identify all controls implemented prior to or during the year of interest and will consider them as viable options at the latest provided level of control.

In other words, since we selected 2009 as the future year of choice, we limit the control factor table to control strategies implemented during or prior to 2009. If in our matching to the control factor table we find that for a certain control basis key there is no match because a program may have been fully implemented in a prior year (say 2007), then we do not want to exclude this reduction from our forecast. Additionally, if we find that there are multiple entries in the control factor table because of incremental implementation of a rule, we select the closest year to that of our intended forecast. So if a particular rule was incrementally implemented from 2005 through 2009 and there were control records available for each year in between, we would select the record with the latest year to apply in our forecast.

The next step was to determine the control basis for each individual emission record of the file. This "control basis" is the key with which the control strategy or technology is associated. Although we developed code to support the hierarchical application of control factors for the BaseM emissions, all control factors provided by MRPO in the Round 5 files were segment-SCC-pollutant specific. This eliminated the need for a search on the key that has the greatest resolution as all matches were at the segment-SCC-pollutant level.

Using the control basis and dates (base year and alternate year), we matched each emission record to the control table to obtain a control factor. The factors are defined in the control table as a group of values (control efficiency, rule effectiveness, and rule penetration) for the future year period that gets assigned to an uncontrolled future year emission value. In other words, we first "backed out" existing base year controls from our future year emissions estimate and then multiplied this uncontrolled value by the control factors for the alternate year of interest. These calculations are defined in Equations 1 and 2 below.

Equation 1. Uncontrolled emissions calculation.

$$Emiss_{Unc} = Emiss_{Base} / (1-((CE_{Base}/100)*(RE_{Base}/100)*(RP_{Base}/100)))$$

Where,

$Emiss_{Unc}$	= Uncontrolled emissions
$Emiss_{Base}$	= Base year emissions
CE_{Base}	= Base year control efficiency
RE_{Base}	= Base year rule effectiveness
RP_{Base}	= Base year rule penetration

Equation 2. Application of new control calculation.

$$Emiss_{New} = Emiss_{Unc} *(1-((CE_{New}/100)*(RE_{New}/100)*(RP_{New}/100)))$$

Where,

$Emiss_{New}$	= Future year emissions
$Emiss_{Unc}$	= Uncontrolled emissions
CE_{New}	= Future year control efficiency
RE_{New}	= Future year rule effectiveness
RP_{New}	= Future year rule penetration

When no match from any of the hierarchical keys was identified, the same control efficiency, rule efficiency, and rule penetration values from the base year inventory were used in the calculation and the only change in emissions would have been the result of growth factor application. In instances where PM-10 annual emissions were found to be less than PM-2.5 annual emission values, the PM-2.5 emission values were changed to equal that of PM-10.

EGU Point Source Conversion

EGU point source emissions from the egu5b_2010 scenario (2010 IPM 3.0 run with modifications) were converted to year 2009 IDA format using the annual emission records directly from the NIF structured data sets. Since these emissions already accounted for growth and control application, no additional modifications were required.

One ASIP requested modification for its PM-2.5 CAMx modeling was to adjust the 2009 file to match W. H. Sammis facility's planned response to the control requirements from the consent decree USA vs. Ohio Edison; Civil Action No: 2:99-CV-1181; March 18, 2005. These changes were not implemented in the ASIP 2009 CMAQ runs. These adjustments for SO2 are noted in Table 2 below.

Table 2. SO2 Control Requirements from USA vs. Ohio Edison Consent Decree

Units 1-4	Induct Scrubbing
	50% removal (1.1 lbs/MMBtu)
	At least one unit by Sept. 30, 2008
	Second unit by Dec. 31, 2008
	Other two units by Dec. 31, 2009
Unit 5	Flash Dryer Absorber or Electro-Catalytic Oxidation no later than Dec. 31, 2008
	50% removal (1.1 lbs/MMBtu)
Units 6/7	Scrubber no later than December 31, 2010
	95% removal (0.13 lbs/MMBtu)
Plantwide	Emission cap of 101,500 by end of 2009
	Emission cap of 101,500 by end of 2010
	Emission cap of 29,900 by end of 2011

Conversion Limitations

As noted above, Alpine limited our conversion to all records in the MRPO point source files that were identified as annual. In some cases the MRPO NIF files had additional non-annual summer season emission records configured as a higher percentage than the annual average that was used in our emissions comparison.

In other words, the MRPO file sometimes had two emission record types that it uses for its modeling; one for the summer period and one for the rest of the year. Since SMOKE uses temporal allocation factors to make this summer/winter split, our converted values do not match MRPO's summertime reports. We see a high percentage difference in the Alpine converted data compared to the MRPO output reports in these two States for the July 12 example for this reason.

Since we confirmed this difference and reason for this difference in the 2005 data sets with MRPO, our objective for QA on the projections also included delta emissions from the projection year to the base year. Although the absolute daily emission values (in tpd) were found to be different as noted above, in all cases, the difference between 2005 and the projection year calculations as made by Alpine was within confidence ranges of the ratio of future year to base year as posted by MRPO. See Table 3 below. For this reason, we were convinced that our projection methodology is capturing the growth and control factors that MRPO applied in its emissions modeling.

Table 3. Emissions Comparison of ASIP Converted and MRPO Non-EGU Emissions.

Comparison of ASIP Converted and MRPO Non-EGU Emissions

		ASIP 2009 Annual Emissions (Tons/Year)						
FIPSST	**State**	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
17	Illinois	61,760	85,142	71,725	150,506	20,315	6,256	1,059
18	Indiana	48,287	65,132	339,642	82,040	22,118	12,774	782
26	Michigan	36,753	85,014	67,564	55,435	13,235	6,567	788
39	Ohio	31,530	67,275	212,626	116,942	15,930	10,443	3,239
55	Wisconsin	31,377	36,827	43,014	60,955	456	43	346
	MRPO	**209,707**	**339,390**	**734,570**	**465,878**	**72,054**	**36,082**	**6,214**

		ASIP 2009 July 12 Summer Daily Emissions (Tons/Day)						
FIPSST	**State**	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
17	Illinois	222.3	315.1	250.9	412.3	55.6	17.1	2.9
18	Indiana	132.3	178.4	930.5	224.8	60.6	35.0	2.1
26	Michigan	115.8	232.4	193.6	144.9	40.8	19.3	2.4
39	Ohio	86.4	184.3	582.5	320.4	43.6	28.6	8.9
55	Wisconsin	86.0	100.9	117.8	167.0	1.3	0.1	0.9
	MRPO	**642.7**	**1,011.1**	**2,075.4**	**1,269.4**	**202.0**	**100.2**	**17.2**

		2009 July 12 Summer Daily Emissions (Tons/Day)						
FIPSST	**State**	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
17	Illinois	218.1	217.8	255.7	335.0	56.0	16.8	2.8
18	Indiana	137.2	175.2	888.8	216.2	60.7	36.5	2.3
26	Michigan	119.1	242.0	206.5	148.6	43.6	20.3	2.4
39	Ohio	87.1	166.3	540.7	288.0	43.0	27.6	8.3
55	Wisconsin	87.7	92.9	120.0	152.1	23.2	0.1	1.0
	MRPO	**649.2**	**894.2**	**2,011.7**	**1,139.9**	**226.5**	**101.3**	**16.8**

		ASIP 2009 July 12 Summer Daily Emissions (% of MRPO Total)						
FIPSST	**State**	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
17	Illinois	29.5%	25.1%	9.8%	32.3%	28.2%	17.3%	17.0%
18	Indiana	23.0%	19.2%	46.2%	17.6%	30.7%	35.4%	12.6%
26	Michigan	17.5%	25.0%	9.2%	11.9%	18.4%	18.2%	12.7%
39	Ohio	15.0%	19.8%	28.9%	25.1%	22.1%	28.9%	52.1%
55	Wisconsin	15.0%	10.9%	5.9%	13.1%	0.6%	0.1%	5.6%
	MRPO	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

		2009 July 12 Summer Daily Emissions (% of MRPO Total)						
FIPSST	**State**	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
17	Illinois	33.6%	24.4%	12.7%	29.4%	24.7%	16.6%	16.7%
18	Indiana	21.1%	19.6%	44.2%	19.0%	26.8%	36.0%	13.7%
26	Michigan	18.3%	27.1%	10.3%	13.0%	19.2%	20.0%	14.3%
39	Ohio	13.4%	18.6%	26.9%	25.3%	19.0%	27.2%	49.4%
55	Wisconsin	13.5%	10.4%	6.0%	13.3%	10.2%	0.1%	6.0%
	MRPO	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

APPENDIX H:

COMPARISON OF EGU CONTROLS FOR COAL AND OIL/GAS UNITS BASED ON IPM MODELING AND STATE-PROVIDED INFORMATION FOR THE BASE G/G2 INVENTORY

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
01033	TVA COLBERT	47	1	0010	010	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	2	0010	011	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	3	0010	012	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	4	0010	013	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	5	0010	014	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
01055	ALABAMA POWER COMPANY GADSDEN	7	1	0002	002	Coal Steam	None	None	None	None	None	None	None	None
01055	ALABAMA POWER COMPANY GADSDEN	7	2	0002	003	Coal Steam	None	None	None	None	None	None	None	None
01063	ALABAMA POWER COMPANY GREENE COUNTY	10	1	0001	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
01063	ALABAMA POWER COMPANY GREENE COUNTY	10	2	0001	003	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
01071	TVA - WIDOWS CREEK	50	1	0008	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	2	0008	003	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	3	0008	004	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	4	0008	005	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	5	0008	006	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	6	0008	007	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	7	0008	008	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
01071	TVA - WIDOWS CREEK	50	8	0008	009	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	4	010730011	001	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	3	010730011	002	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	2	010730011	004	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	1	010730011	005	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01097	ALABAMA POWER COMPANY BARRY	3	1	1001	002	Coal Steam	SNCR	None	SNCR	SCR	None	None	None	None
01097	ALABAMA POWER COMPANY BARRY	3	2	1001	003	Coal Steam	SNCR	None	SNCR	SCR	None	None	None	None
01097	ALABAMA POWER COMPANY BARRY	3	3	1001	004	Coal Steam	SNCR	None	SNCR	SCR	None	None	None	None
01097	ALABAMA POWER COMPANY BARRY	3	4	1001	005	Coal Steam	SNCR	None	SNCR	SCR	None	None	Scrubber	Scrubber
01097	ALABAMA POWER COMPANY BARRY	3	5	1001	006	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	1	0005	002	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	2	0005	003	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	3	0005	004	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	4	0005	005	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	5	0005	006	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
01127	ALABAMA POWER COMPANY GORGAS	8	6	0001	004	Coal Steam	None	None	None	None	None	None	None	None
01127	ALABAMA POWER COMPANY GORGAS	8	7	0001	005	Coal Steam	None	None	None	None	None	None	None	None
01127	ALABAMA POWER COMPANY GORGAS	8	8	0001	006	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
01127	ALABAMA POWER COMPANY GORGAS	8	9	0001	007	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
01127	ALABAMA POWER COMPANY GORGAS	8	10	0001	008	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber
01129	ALABAMA ELECTRIC COOP CHARLES R LOWMAN	56	1	0001	002	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
01129	ALABAMA ELECTRIC COOP CHARLES R LOWMAN	56	2	0001	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
01129	ALABAMA ELECTRIC COOP CHARLES R LOWMAN	56	3	0001	004	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12001	GAINESVILLE REGIONAL UTILITIES JOHN R KELLY	664	JRK6			O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12001	GAINESVILLE REGIONAL UTILITIES JOHN R KELLY	664	JRK7			O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12001	GAINESVILLE REGIONAL UTILITIES JOHN R KELLY	664	JRK8	0010005	7		O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12001	CITY OF GAINESVILLE, GRU DEERHAVEN	663	B1	0010006	3	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12001	CITY OF GAINESVILLE, GRU DEERHAVEN	663	B2	0010006	5	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
12005	GULF POWER COMPANY LANSING SMITH PLANT	643	1	0050014	1	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
12005	GULF POWER COMPANY LANSING SMITH PLANT	643	2	0050014	2	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
12009	FLORIDA POWER & LIGHT (PCC) CAPE CANAVERAL	609	PCC1	0090006	1	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12009	FLORIDA POWER & LIGHT (PCC) CAPE CANAVERAL	609	PCC2	0090006	2	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE1	0110036	1	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE2	0110036	2	O/G Steam	None	None	None	None	None	None	None	None
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE3	0110036	3	O/G Steam	None	None	None	None	None	None	None	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE4	0110036	4	O/G Steam	None	None	None	None	None	None	None	None
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	1	0170004	1	Coal Steam	None	None	None	None	None	None	None	None
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	2	0170004	2	Coal Steam	None	None	None	None	None	None	None	None
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	5	0170004	3	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	4	0170004	4	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	SAINT JOHNS RIVER	207	1	0310045-A	16		SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	SAINT JOHNS RIVER	207	2	0310045-A	17		SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	NORTHSIDE	667	2A	0310045-B	26	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	None	No Operation
12031	NORTHSIDE	667	1A	0310045-B	27	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	None	No Operation
12031	NORTHSIDE	667	3	0310045-B	3	O/G Steam	None	None	None	No Operation	None	None	None	None
12031	CEDAR BAY COGENERATION INC.	10672	GEN1	0310337	1	Coal Steam	None	SNCR	None	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	CEDAR BAY COGENERATION INC.			0310337	2									
12031	CEDAR BAY COGENERATION INC.			0310337	3									
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	1	0330045	1									
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	2	0330045	2	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	3	0330045	3	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	4	0330045	4	Coal Steam	None	None	None	None	None	None	Scrubber	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	5	0330045	5	Coal Steam	None	None	None	None	None	None	Scrubber	None
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	6	0330045	6	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	None
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	7	0330045	7	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
12053	Central Power and Lime Incorporated	10333	GEN1	0530021	18	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB01	0570039	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB02	0570039	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB03	0570039	3	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB04	0570039	4	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB01	0570040	1		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB02	0570040	2		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB03	0570040	3		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB04	0570040	4		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB05	0570040	5		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB06	0570040	6		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12061	CITY OF VERO BEACH	693		0610029	1	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12061	CITY OF VERO BEACH	693	3	0610029	3	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12061	CITY OF VERO BEACH	693	4	0610029	4	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12063	GULF POWER COMPANY SCHOLZ	642	1	0630014	1	Coal Steam	None	None	None	None	None	None	None	None
12063	GULF POWER COMPANY SCHOLZ	642	2	0630014	2	Coal Steam	None	None	None	None	None	None	None	None
12073	CITY OF TALLAHASSEE ARVAH B.HOPKINS	688	1	0730003	1	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12073	CITY OF TALLAHASSEE ARVAH B.HOPKINS	688	2	0730003	4	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12081	FLORIDA POWER & LIGHT (PMT) MANATEE POWER	6042	PMT1	0810010	1	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12081	FLORIDA POWER & LIGHT (PMT) MANATEE POWER	6042	PMT2	0810010	2	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12085	FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	6043	PMR1	0850001	1	O/G Steam	None	None	No Operation	No Operation	None	None	No Operation	No Operation
12085	FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	6043	PMR2	0850001	2	O/G Steam	None	None	No Operation	No Operation	None	None	No Operation	No Operation
12085	INDIANTOWN COGENERATION, L.P.	50976	GEN1	0850102	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12086	FLORIDA POWER & LIGHT (PCU) CUTLER POWER	610	PCU5	0250001	3	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12086	FLORIDA POWER & LIGHT (PCU) CUTLER POWER	610	PCU6	0250001	4	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12086	FLORIDA POWER & LIGHT (PTF) TURKEY POINT	621	PTP1	0250003	1	O/G Steam	None	None	No Operation	No Operation	None	None	No Operation	No Operation
12086	FLORIDA POWER & LIGHT (PTF) TURKEY POINT	621	PTP2	0250003	2	O/G Steam	None	None	No Operation	No Operation	None	None	No Operation	No Operation
12095	ORLANDO UTILITIES COMMISSION STANTON ENERGY	564	1	0950137	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12095	ORLANDO UTILITIES COMMISSION STANTON ENERGY	564	2	0950137	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12099	FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	619	PRV3	0990042	3	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12099	FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	619	PRV4	0990042	4	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12099	CITY OF LAKE WORTH UTILITIES TOM G. SMITH	673	S-1	0990045	7	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12099	CITY OF LAKE WORTH UTILITIES TOM G. SMITH	673	S-3	0990045	9	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12101	PROGRESS ENERGY FLORIDA ANCLOTE	8048	1	1010017	1	O/G Steam	None	None	No Operation	No Operation	None	None	No Operation	No Operation
12101	PROGRESS ENERGY FLORIDA ANCLOTE	8048	2	1010017	2	O/G Steam	None	None	No Operation	No Operation	None	None	No Operation	No Operation
12103	PROGRESS ENERGY FLORIDA BARTOW	634	1	1030011	1	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	No Operation	No Operation
12103	PROGRESS ENERGY FLORIDA BARTOW	634	2	1030011	2	O/G Steam	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12103	PROGRESS ENERGY FLORIDA BARTOW	634	3	1030011	3	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	No Operation	No Operation
12105	LAKELAND ELECTRIC CHARLES LARSEN	675	7	1050003	4	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12105	LAKELAND ELECTRIC C.D. MCINTOSH, JR.	676	3	1050004	6	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12107	SEMINOLE ELECTRIC COOPERATIVE, INC.	136	1	1070025	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12107	SEMINOLE ELECTRIC COOPERATIVE, INC.	136	2	1070025	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12111	FT PIERCE UTILITIES AUTHORITY FT PIERCE	658	7	1110003	7	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12111	FT PIERCE UTILITIES AUTHORITY FT PIERCE	658	8	1110003	8	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12121	PROGRESS ENERGY FLORIDA SUWANNEE RIVER	638	1	1210003	1	O/G Steam	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12121	PROGRESS ENERGY FLORIDA SUWANNEE RIVER	638	2	1210003	2	O/G Steam	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12121	PROGRESS ENERGY FLORIDA SUWANNEE RIVER	638	3	1210003	3	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	No Operation	No Operation
12127	FLORIDA POWER & LIGHT (PSN) SANFORD POWER	620	PSN3	1270009	1	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12127	FLORIDA POWER & LIGHT (PSN) SANFORD POWER	620	PSN4	1270009	2		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12129	TALLAHASSEE CITY PURDOM GENERATING STATION	689	7	1290001	7	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	1BLR	01500011	SG01	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	2BLR	01500011	SG02	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	3BLR	01500011	SG03	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	4BLR	01500011	SG04	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
13021	ARKWRIGHT	699	1	0002	1		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13021	ARKWRIGHT	699	2	0002	2		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13021	ARKWRIGHT	699	3	0002	3		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13021	ARKWRIGHT	699	4	0002	4		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	1	05100006	SG01	Coal Steam	None	None	None	None	None	None	None	None
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	2	05100006	SG02	Coal Steam	None	None	None	None	None	None	None	None
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	3	05100006	SG03	Coal Steam	None	None	None	SCR	None	None	None	None
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	4	05100006	SG04	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	11	05100018	11	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	12	05100018	12	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	4	05100018	4	O/G Steam	None	None	None	None	None	None	None	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
13051	RIVERSIDE	734	5	05100018	5	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	6	05100018	6	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13067	GEORGIA POWER COMPANY, MCDONOUGH STEAM	710	MB1	06700003	SGM1	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13067	GEORGIA POWER COMPANY, MCDONOUGH STEAM	710	MB2	06700003	SGM2	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y1BR	07700001	SG01	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y2BR	07700001	SG02	Coal Steam	None	None	None	None	None	None	None	None
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y3BR	07700001	SG03	Coal Steam	None	None	None	None	None	None	None	None
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y4BR	07700001	SG04	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y5BR	07700001	SG05	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y6BR	07700001	SG06	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y7BR	07700001	SG07	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13095	GEORGIA POWER COMPANY, MITCHELL STEAM-ELECTRIC	727		09500002	SG01		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13095	GEORGIA POWER COMPANY, MITCHELL STEAM-ELECTRIC	727		09500002	SG02		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13095	GEORGIA POWER COMPANY, MITCHELL STEAM-ELECTRIC	727	3	09500002	SG03	Coal Steam	None	None	None	None	None	None	None	None
13103	SAVANNAH ELECTRIC: MCINTOSH STEAM - ELECTRIC	6124	1	10300003	SG01	Coal Steam	None	None	None	SCR	None	None	None	None
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	1	11500003	SG01	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	2	11500003	SG02	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	3	11500003	SG03	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	4	11500003	SG04	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
13127	GEORGIA POWER COMPANY, MCMANUS STEAM-ELECTRIC	715	1	12700004	SG01	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13127	GEORGIA POWER COMPANY, MCMANUS STEAM-ELECTRIC	715	2	12700004	SG02	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13149	GEORGIA POWER COMPANY, WANSLEY STEAM-ELECTRIC	6052	1	14900001	SG01	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
13149	GEORGIA POWER COMPANY, WANSLEY STEAM-ELECTRIC	6052	2	14900001	SG02	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	1	20700008	SG01	Coal Steam	None	None	None	None	None	None	Scrubber	None
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	2	20700008	SG02	Coal Steam	None	None	None	None	None	None	Scrubber	None
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	3	20700008	SG03	Coal Steam	None	None	None	None	None	None	Scrubber	None
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	4	20700008	SG04	Coal Steam	None	None	None	None	None	None	Scrubber	None
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	1	23700008	SG01	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	2	23700008	SG02	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	3	23700008	SG03	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	4	23700008	SG04	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
21015	CINCINNATI GAS & ELECTRIC EAST BEND STAT	6018	2	2101500029	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	1	2104100010	001	Coal Steam	SCR	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	2	2104100010	002	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	3	2104100010	003	Coal Steam	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	4	2104100010	004	Coal Steam	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	1	2104900003	001	Coal Steam	None	None	None	None	None	None	None	None
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	2	2104900003	002	Coal Steam	None	None	None	None	None	None	None	None
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	3	2104900003	003	Coal Steam	None	None	None	None	None	None	None	None
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	4	2104900003	004	Coal Steam	None	None	None	None	None	None	None	None
21059	OWENSBORO MUNICIPAL UTIL ELMER SMITH STATION	1374	1	2105900027	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21059	OWENSBORO MUNICIPAL UTIL ELMER SMITH STATION	1374	2	2105900027	002	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21091	WESTERN KY ENERGY CORP COLEMAN STATION	1381	C1	2109100003	001	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21091	WESTERN KY ENERGY CORP COLEMAN STATION	1381	C2	2109100003	002	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21091	WESTERN KY ENERGY CORP COLEMAN STATION	1381	C3	2109100003	003	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21101	HENDERSON MUN POW & LIGHT	1372	6	2110100012	002	Coal Steam	None	None	None	None	None	None	None	None
21101	HENDERSON MUN POW & LIGHT	1372	5	2110100012	5	Coal Steam	None	None	None	None	None	None	None	None
21111	LOU GAS & ELEC, CANE RUN	1363	4	0126	04	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, CANE RUN	1363	5	0126	05	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, CANE RUN	1363	6	0126	06	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, MILL CREEK	1364	1	0127	01	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21111	LOU GAS & ELEC, MILL CREEK	1364	2	0127	02	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, MILL CREEK	1364	3	0127	03	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, MILL CREEK	1364	4	0127	04	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21127	KENTUCKY POWER CO BIG SANDY PLANT	1353	BSU1	2112700003	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21127	KENTUCKY POWER CO BIG SANDY PLANT	1353	BSU2	2112700003	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	1	2114500006	001	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	2	2114500006	002	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	3	2114500006	003	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	4	2114500006	004	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	5	2114500006	005	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	6	2114500006	006	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	7	2114500006	007	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	8	2114500006	008	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	9	2114500006	009	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	10	2114500006	016	Coal Steam	None	None	None	None	None	None	None	None
21161	EAST KY POWER COOP SPURLOCK ST. MAYSVILLE	6041	1	2116100009	001	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21161	EAST KY POWER COOP SPURLOCK ST. MAYSVILLE	6041	2	2116100009	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
21167	KENTUCKY UTILITIES CO BROWN FACILITY	1355	1	2116700001	001	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
21167	KENTUCKY UTILITIES CO BROWN FACILITY	1355	2	2116700001	002	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21167	KENTUCKY UTILITIES CO BROWN FACILITY	1355	3	2116700001	003	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21177	KENTUCKY UTILITIES CO GREEN RIVER STATION	1357	4	2117700001	003	Coal Steam	None	None	None	None	None	None	None	None
21177	KENTUCKY UTILITIES CO GREEN RIVER STATION	1357	5	2117700001	004	Coal Steam	None	None	None	None	None	None	None	None
21177	TVA PARADISE STEAM PLANT	1378	1	2117700006	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21177	TVA PARADISE STEAM PLANT	1378	2	2117700006	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21177	TVA PARADISE STEAM PLANT	1378	3	2117700006	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21183	WESTERN KY ENERGY CORP WILSON STATION	6823	W1	2118300069	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21199	EAST KY POWER COOP JOHN SHERMAN COOPER	1384	1	2119900005	001	Coal Steam	None	None	None	None	None	None	None	None
21199	EAST KY POWER COOP JOHN SHERMAN COOPER	1384	2	2119900005	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
21223	LOUISVILLE GAS & ELECTRIC TRIMBLE CO GEN	6071	1	2122300002	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21233	HENDERSON STATION 2	1382	H1	2123300001-A	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21233	HENDERSON STATION 2	1382	H2	2123300001-A	003	Coal Steam	SCR	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21233	WESTERN KY ENERGY CORP REID	1383	R1	2123300001-B	001	Coal Steam	None	None	None	None	None	None	None	None
21233	WESTERN KY ENERGY CORP GREEN STATION	6639	G1	2123300052	001	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21233	WESTERN KY ENERGY CORP GREEN STATION	6639	G2	2123300052	002	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21239	KENTUCKY UTILITIES TYRONE FACILITY	1361	5	2123900001	005	Coal Steam	None	None	None	None	None	None	None	None
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051	1	2801100031	001	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051		2801100031	002		O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051	2	2801100031	003	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051		2801100031	004		O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28019	CHOCTAW GENERATION LLP, RED HILLS GENERATING	55076	AA001	2801900011	001A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
28019	CHOCTAW GENERATION LLP, RED HILLS GENERATING	55076	AA002	2801900011	001B		None	None	None	None	None	None	None	None
28035	MISSISSIPPI POWER COMPANY, PLANT EATON	2046		2803500038	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28035	MISSISSIPPI POWER COMPANY, PLANT EATON	2046		2803500038	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28035	MISSISSIPPI POWER COMPANY, PLANT EATON	2046		2803500038	003	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	1	2804700055	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	2	2804700055	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	3	2804700055	003	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	4	2804700055	004	Coal Steam	None	SCR	SCR	SCR	None	None	None	Scrubber
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	5	2804700055	005	Coal Steam	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
28049	ENTERGY MISSISSIPPI INC, REX BROWN PLANT	2053	4	2804900112	001	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28049	ENTERGY MISSISSIPPI INC, REX BROWN PLANT	2053	3	2804900112	002	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28059	MISSISSIPPI POWER COMPANY, PLANT DANIEL	6073	1	2805900090	001	Coal Steam	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
28059	MISSISSIPPI POWER COMPANY, PLANT DANIEL	6073	2	2805900090	002	Coal Steam	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
28067	MOSELLE SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	2070	1	2806700035	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28067	MOSELLE SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	2070	2	2806700035	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28067	MOSELLE SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	2070	3	2806700035	003	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28073	RD MORROW SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	6061	1	2807300021	001	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
28073	RD MORROW SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	6061	2	2807300021	002	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
28075	MISSISSIPPI POWER COMPANY, PLANT SWEATT	2048	1	2807500032	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28075	MISSISSIPPI POWER COMPANY, PLANT SWEATT	2048	2	2807500032	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28083	GREENWOOD UTILITIES, HENDERSON STATION	2062	H1	2808300048	001	O/G Steam	None	None	None	None	No Operation	No Operation	No Operation	No Operation
28083	GREENWOOD UTILITIES, HENDERSON STATION	2062	H3	2808300048	003	O/G Steam	None	None	None	None	No Operation	No Operation	No Operation	No Operation
28149	ENTERGY MISSISSIPPI INC, BAXTER WILSON	2050	1	2814900027	001	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28149	ENTERGY MISSISSIPPI INC, BAXTER WILSON	2050	2	2814900027	002	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
28151	ENTERGY MISSISSIPPI INC, GERALD ANDRUS	8054	1	2815100048	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
28163	YAZOO CITY PUBLIC SERVICE COMMISSION	2067	3	2816300005	001	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
37017	ELIZABETHTOWN POWER, LLC	10380	UNIT1	3701700043	G-17A	Coal Steam	None	None	None	None	None	None	None	None
37017	ELIZABETHTOWN POWER, LLC	10380	UNIT2	3701700043	G-17B		None	None	None	None	None	None	None	None
37019	COGENTRIX OF NORTH CAROLINA INC - SOUTHPORT	10378	GEN1	3701900067	G-29	Coal Steam	None	None	None	None	None	None	None	None
37019	COGENTRIX OF NORTH CAROLINA INC - SOUTHPORT	10378	GEN2	3701900067	G-30	Coal Steam	None	None	None	None	None	None	None	None
37021	CAROLINA POWER & LIGHT ASHEVILLE STEAM	2706	1	628	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37021	CAROLINA POWER & LIGHT ASHEVILLE STEAM	2706	2	628	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37025	KANNAPOLIS ENERGY PARTNERS LLC			3702500113	G-2	Coal Steam	None	None	None	None	None	None	None	None
37025	KANNAPOLIS ENERGY PARTNERS LLC			3702500113	G-3	Coal Steam	None	None	None	None	None	None	None	None
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	3	3703500073	G-1	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	4	3703500073	G-2	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	1	3703500073	G-4	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	2	3703500073	G-5	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37037	PROGRESS ENERGY CAROLINAS CAPE FEAR	2708	5	3703700063	G-1	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	Scrubber
37037	PROGRESS ENERGY CAROLINAS CAPE FEAR	2708	6	3703700063	G-2	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	1	3707100039	G-14	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	2	3707100039	G-15	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	3	3707100039	G-16	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	4	3707100039	G-17	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	5	3707100039	G-18	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	7	3707100040	G-17	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	8	3707100040	G-18	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	9	3707100040	G-19	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	10	3707100040	G-20	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37083	ROANOKE VALLEY ENERGY FACILITY			3708300174	G-27	Coal Steam	None	None	None	None	None	None	None	None
37083	ROANOKE VALLEY ENERGY FACILITY			3708300174	G-7	Coal Steam	None	None	None	None	None	None	None	None
37129	L V SUTTON STEAM ELECTRIC PLANT	2713	1	3712900036	G-187	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37129	L V SUTTON STEAM ELECTRIC PLANT	2713	2	3712900036	G-188	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
37129	L V SUTTON STEAM ELECTRIC PLANT	2713	3	3712900036	G-189	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	1	3714500029	G-29	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	2	3714500029	G-30	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	3A	3714500029	G-35A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	3B	3714500029	G-35B	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	4A	3714500029	G-36A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	4B	3714500029	G-36B	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - MAYO FACILITY	6250	1A	3714500045	G-46A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - MAYO FACILITY	6250	1B	3714500045	G-46B	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37155	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	2716	1	3715500147	G-24	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37155	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	2716	2	3715500147	G-25	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37155	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	2716	3	3715500147	G-26	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37155	LUMBERTON POWER, LLC	10382	UNIT1	3715500166	G-17A	Coal Steam	None	None	None	None	None	None	None	None
37155	LUMBERTON POWER, LLC	10382	UNIT2	3715500166	G-17B		None	None	None	None	None	None	None	None
37157	DUKE ENERGY CORP DAN RIVER STEAM	2723	3	3715700015	G-21	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37157	DUKE ENERGY CORP DAN RIVER STEAM	2723	1	3715700015	G-22	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37157	DUKE ENERGY CORP DAN RIVER STEAM	2723	2	3715700015	G-23	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	5	3715900004	G-1	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	6	3715900004	G-2	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	7	3715900004	G-3	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	8	3715900004	G-4	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	9	3715900004	G-5	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	1	3716100028	G-82	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	2	3716100028	G-83	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	3	3716100028	G-84	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	4	3716100028	G-85	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	5	3716100028	G-86	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	6	3716100028	G-87		No Operation	Not in IPM	SCR	Not in IPM	No Operation	Not in IPM	Scrubber	Not in IPM
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	7	3716100028	G-88		No Operation	Not in IPM	SCR	Not in IPM	No Operation	Not in IPM	Scrubber	Not in IPM
37169	DUKE ENERGY CORP BELEWS CREEK STEAM	8042	1	3716900004	G-17	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37169	DUKE ENERGY CORP BELEWS CREEK STEAM	8042	2	3716900004	G-18	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37191	PROGRESS ENERGY F LEE PLANT	2709	1	3719100017	G-2	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37191	PROGRESS ENERGY F LEE PLANT	2709	2	3719100017	G-3	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37191	PROGRESS ENERGY F LEE PLANT	2709	3	3719100017	G-4	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	None	Scrubber
45003	SCE&G:URQUHART	3295	URQ3	0080-0011	003	Coal Steam	None	None	None	None	None	None	None	None
45003	SCE&G:SRS AREA D			0080-0044	001	Coal Steam	None	None	None	None	None	None	None	None
45003	SCE&G:SRS AREA D			0080-0044	002		None	None	None	None	None	None	None	None
45003	SCE&G:SRS AREA D			0080-0044	003		None	None	None	None	None	None	None	None
45003	SCE&G:SRS AREA D			0080-0044	004		None	None	None	None	None	None	None	None

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
45007	DUKE ENERGY:LEE	3264	1	0200-0004	001	Coal Steam	None	None	None	None	None	None	None	None
45007	DUKE ENERGY:LEE	3264	2	0200-0004	002	Coal Steam	None	None	None	None	None	None	None	None
45007	DUKE ENERGY:LEE	3264	3	0200-0004	003	Coal Steam	None	None	None	None	None	None	None	None
45015	SANTEE COOPER JEFFERIES	3319	1	0420-0003	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
45015	SANTEE COOPER JEFFERIES	3319	2	0420-0003	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
45015	SANTEE COOPER JEFFERIES	3319	3	0420-0003	003	Coal Steam	None	SCR	None	SCR	None	None	None	None
45015	SANTEE COOPER JEFFERIES	3319	4	0420-0003	004	Coal Steam	None	None	None	None	None	None	None	None
45015	SCE&G:WILLIAMS	3298	WIL1	0420-0006	001	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
45015	SANTEE COOPER CROSS	130	1	0420-0030	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45015	SANTEE COOPER CROSS	130	2	0420-0030	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45015	SANTEE COOPER CROSS	130	3	0420-0030	3	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
45015	SANTEE COOPER CROSS	130	4	0420-0030	4		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
45029	SCE&G:CANADYS	3280	CAN1	0740-0002	001	Coal Steam	None	None	None	None	None	None	None	None
45029	SCE&G:CANADYS	3280	CAN2	0740-0002	002	Coal Steam	None	None	None	None	None	None	None	None
45029	SCE&G:CANADYS	3280	CAN3	0740-0002	003	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
45031	PROGRESS ENERGY ROBINSON STATION	3251	1	0820-0002	001	Coal Steam	None	None	None	None	None	None	None	None
45043	SANTEE COOPER WINYAH	6249	1	1140-0005	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
45043	SANTEE COOPER WINYAH	6249	2	1140-0005	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
45043	SANTEE COOPER WINYAH	6249	3	1140-0005	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45043	SANTEE COOPER WINYAH	6249	4	1140-0005	004	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45051	SANTEE COOPER GRAINGER	3317	1	1340-0003	001	Coal Steam	None	None	None	None	None	None	None	None
45051	SANTEE COOPER GRAINGER	3317	2	1340-0003	002	Coal Steam	None	None	None	None	None	None	None	None
45063	SCE&G:MCMEEKIN	3287	MCM1	1560-0003	001	Coal Steam	None	None	None	None	None	None	None	None
45063	SCE&G:MCMEEKIN	3287	MCM2	1560-0003	002	Coal Steam	None	None	None	None	None	None	None	None
45075	SCE&G:COPE	7210	COP1	1860-0044	001	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
45079	SCE&G:WATEREE	3297	WAT1	1900-0013	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	None
45079	SCE&G:WATEREE	3297	WAT2	1900-0013	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber
47001	TVA BULL RUN FOSSIL PLANT	3396	1	0009	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	1	0007	001	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	2	0007	002	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	3	0007	003	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	4	0007	004	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	1	0011	001	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	2	0011	002	Coal Steam	None	SCR	SCR	SCR	None	None	None	None

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	3	0011	003	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	4	0011	004	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	5	0011	005	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	6	0011	006	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	7	0011	007	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	8	0011	008	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	9	0011	009	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	10	0011	010	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47145	TVA KINGSTON FOSSIL PLANT	3407	1	0013	001	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	2	0013	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	3	0013	003	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	4	0013	004	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	5	0013	005	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	6	0013	006	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	7	0013	007	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	8	0013	008	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	9	0013	009	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
47157	ALLEN FOSSIL PLANT	3393	1	00528	Boilr1	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
47157	ALLEN FOSSIL PLANT	3393	2	00528	Boilr2	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
47157	ALLEN FOSSIL PLANT	3393	3	00528	Boilr3	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
47161	TVA CUMBERLAND FOSSIL PLANT	3399	1	0011	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
47161	TVA CUMBERLAND FOSSIL PLANT	3399	2	0011	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	1	0025	001	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	2	0025	002	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	3	0025	003	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	4	0025	004	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
51031	DOMINION - ALTAVISTA POWER STATION	10773	1	00156	1	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
51031	DOMINION - ALTAVISTA POWER STATION	10773	2	00156	2		None	None	None	None	None	None	None	None
51041	DOMINION - CHESTERFIELD POWER STATION	3797	3	00002	3	Coal Steam	None	None	None	None	None	None	Scrubber	None
51041	DOMINION - CHESTERFIELD POWER STATION	3797	4	00002	4	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber
51041	DOMINION - CHESTERFIELD POWER STATION	3797	5	00002	6	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber
51041	DOMINION - CHESTERFIELD POWER STATION	3797	6	00002	8	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
51065	DOMINION - BREMO POWER STATION	3796	3	00001	1	Coal Steam	None	None	None	None	None	None	None	None
51065	DOMINION - BREMO POWER STATION	3796	4	00001	2	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
51071	AMERICAN ELECTRIC POWER GLEN LYN	3776	51	00002	1	Coal Steam	None	None	None	None	None	None	None	None
51071	AMERICAN ELECTRIC POWER GLEN LYN	3776	52	00002	2	Coal Steam	None	None	None	None	None	None	None	None
51071	AMERICAN ELECTRIC POWER GLEN LYN	3776	6	00002	3	Coal Steam	None	None	None	None	None	None	None	Scrubber
51083	DOMINION - CLOVER POWER STATION	7213	1	00046	1	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
51083	DOMINION - CLOVER POWER STATION	7213	2	00046	2	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
51099	BIRCHWOOD POWER PARTNERS, L.P.	54304	1	00012	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
51117	Mecklenburg Cogeneration Facility	52007	GEN1	00051	1	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
51117	Mecklenburg Cogeneration Facility	52007	GEN2	00051	2	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
51153	DOMINION - POSSUM POINT	3804	3	00002	3	Coal Steam	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle
51153	DOMINION - POSSUM POINT	3804	4	00002	4	Coal Steam	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle
51153	DOMINION - POSSUM POINT	3804	5	00002	5	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
51153	DOMINION - POSSUM POINT	3804	6	00002		Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle
51167	AMERICAN ELECTRIC POWER CLINCH RIVER PLANT	3775	1	00003	1	Coal Steam	None	None	None	SCR	None	None	None	Scrubber
51167	AMERICAN ELECTRIC POWER CLINCH RIVER PLANT	3775	2	00003	2	Coal Steam	None	None	None	SCR	None	None	None	Scrubber
51167	AMERICAN ELECTRIC POWER CLINCH RIVER PLANT	3775	3	00003	3	Coal Steam	None	None	None	SCR	None	None	None	Scrubber
51175	LG&E Westmoreland Southampton	10774	GEN1	00051	1	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
51175	LG&E Westmoreland Southampton			00051	2		None	None	None	None	None	None	None	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
51175	LG&E Westmoreland Southampton			00051	4		None	None	None	None	None	None	None	None
51199	DOMINION - YORKTOWN POWER STATION	3809	3	00001	3	O/G Steam	SNCR	No Operation	SNCR	No Operation	None	No Operation	Scrubber	No Operation
51199	DOMINION - YORKTOWN POWER STATION	3809	2	00001	5	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	None
51199	DOMINION - YORKTOWN POWER STATION	3809	1	00001	6	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	None
51510	POTOMAC RIVER GENERATING STATION	3788	1	00003	1	Coal Steam	SNCR	Coal Early Retirement	SNCR	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement
51510	POTOMAC RIVER GENERATING STATION	3788	2	00003	2	Coal Steam	SNCR	Coal Early Retirement	SNCR	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement
51510	POTOMAC RIVER GENERATING STATION	3788	3	00003	3	Coal Steam	SNCR	None	SNCR	None	None	None	None	None
51510	POTOMAC RIVER GENERATING STATION	3788	4	00003	4	Coal Steam	SNCR	None	SNCR	None	None	None	None	None
51510	POTOMAC RIVER GENERATING STATION	3788	5	00003	5	Coal Steam	SNCR	None	SNCR	None	None	None	None	None
51550	DOMINION - CHESAPEAKE	3803	1	00026	1	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	None
51550	DOMINION - CHESAPEAKE	3803	2	00026	2	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	None
51550	DOMINION - CHESAPEAKE	3803	3	00026	3	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber
51550	DOMINION - CHESAPEAKE	3803	4	00026	4	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber
54023	MOUNT STORM POWER PLANT	3954	1	0003	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54023	MOUNT STORM POWER PLANT	3954	2	0003	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54023	MOUNT STORM POWER PLANT	3954	3	0003	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54023	NORTH BRANCH POWER STATION	7537	1A	0014	001	Coal Steam	None	None	None	None	None	None	None	None

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
54023	NORTH BRANCH POWER STATION	7537	1B	0014	002	Coal Steam	None	None	None	None	None	None	None	None
54033	MONONGAHELA POWER CO HARRISON	3944	1	0015	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54033	MONONGAHELA POWER CO HARRISON	3944	2	0015	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54033	MONONGAHELA POWER CO HARRISON	3944	3	0015	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54039	APPALACHIAN POWER KANAWHA RIVER PLANT	3936	1	0006	001	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54039	APPALACHIAN POWER KANAWHA RIVER PLANT	3936	2	0006	002	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54049	MONONGAHELA POWER CO. RIVESVILLE POWER	3945	7	0009	001	Coal Steam	None	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54049	MONONGAHELA POWER CO. RIVESVILLE POWER	3945	8	0009	002	Coal Steam	None	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54049	AMERICAN BITUMINOUS POWER GRANT TOWN PLT	10151		0026	001		None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
54049	GRANT TOWN POWER PLANT	10151	GEN1	ORIS10151	GEN1	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
54051	OHIO POWER MITCHELL PLANT	3948	1	0005	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54051	OHIO POWER MITCHELL PLANT	3948	2	0005	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54051	OHIO POWER KAMMER PLANT	3947	1	0006	001	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54051	OHIO POWER KAMMER PLANT	3947	2	0006	002	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54051	OHIO POWER KAMMER PLANT	3947	3	0006	003	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	11	0001	001	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	21	0001	002	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	31	0001	003	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	41	0001	004	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	51	0001	005	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER MOUNTAINEER PLANT	6264	1	0009		Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54061	MONONGAHELA POWER CO. FORT MARTIN POWER	3943	1	0001	001	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	Scrubber
54061	MONONGAHELA POWER CO. FORT MARTIN POWER	3943	2	0001	002	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	Scrubber
54061	MORGANTOWN ENERGY ASSOCIATES			0027	043		None	None	None	None	None	None	None	None
54061	MORGANTOWN ENERGY FACILITY	10743	GEN1	ORIS10743	GEN1	Coal Steam	None	None	None	None	None	None	None	None
54073	MONONGAHELA POWER CO. WILLOW ISLAND	3946	1	0004	001	Coal Steam	None	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54073	MONONGAHELA POWER CO. WILLOW ISLAND	3946	2	0004	002	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54073	MONONGAHELA POWER CO PLEASANTS POWER STATION	6004	1	0005	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54073	MONONGAHELA POWER CO PLEASANTS POWER STATION	6004	2	0005	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber Upgrade	Scrubber
54077	MONONGAHELA POWER CO ALBRIGHT	3942	1	0001	001	Coal Steam	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54077	MONONGAHELA POWER CO ALBRIGHT	3942	2	0001	002	Coal Steam	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54077	MONONGAHELA POWER CO ALBRIGHT	3942	3	0001	003	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54079	APPALACHIAN POWER JOHN E AMOS PLANT	3935	1	0006	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54079	APPALACHIAN POWER JOHN E AMOS PLANT	3935	2	0006	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX H: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE BASE G/G2 INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
54079	APPALACHIAN POWER JOHN E AMOS PLANT	3935	3	0006	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX I:

COMPARISON OF EGU CONTROLS FOR COAL AND OIL/GAS UNITS BASED ON IPM MODELING AND STATE-PROVIDED INFORMATION FOR THE B&F INVENTORY

APPENDIX I: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE B&F INVENTORY

							Post-Combustion Controls							
FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
01033	TVA COLBERT	47	1	0010	010	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	2	0010	011	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	3	0010	012	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	4	0010	013	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01033	TVA COLBERT	47	5	0010	014	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
01055	ALABAMA POWER COMPANY GADSDEN	7	1	0002	002	Coal Steam	None	None	None	None	None	None	None	None
01055	ALABAMA POWER COMPANY GADSDEN	7	2	0002	003	Coal Steam	None	None	None	None	None	None	None	None
01063	ALABAMA POWER COMPANY GREENE COUNTY	10	1	0001	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
01063	ALABAMA POWER COMPANY GREENE COUNTY	10	2	0001	003	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
01071	TVA - WIDOWS CREEK	50	1	0008	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	2	0008	003	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	3	0008	004	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	4	0008	005	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	5	0008	006	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	6	0008	007	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
01071	TVA - WIDOWS CREEK	50	7	0008	008	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

APPENDIX I: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE B&F INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
01071	TVA - WIDOWS CREEK	50	8	0008	009	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	4	010730011	001	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	3	010730011	002	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	2	010730011	004	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01073	ALABAMA POWER COMPANY (MILLER POWER PLANT)	6002	1	010730011	005	Coal Steam	SCR All Year	SCR Summer	SCR All Year	SCR Summer	None	None	Scrubber	None
01097	ALABAMA POWER COMPANY BARRY	3	1	1001	002	Coal Steam	SNCR	None	SNCR	SCR	None	None	None	None
01097	ALABAMA POWER COMPANY BARRY	3	2	1001	003	Coal Steam	SNCR	None	SNCR	SCR	None	None	None	None
01097	ALABAMA POWER COMPANY BARRY	3	3	1001	004	Coal Steam	SNCR	None	SNCR	SCR	None	None	None	None
01097	ALABAMA POWER COMPANY BARRY	3	4	1001	005	Coal Steam	SNCR	None	SNCR	SCR	None	None	Scrubber	Scrubber
01097	ALABAMA POWER COMPANY BARRY	3	5	1001	006	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	1	0005	002	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	2	0005	003	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	3	0005	004	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	4	0005	005	Coal Steam	None	SCR	None	SCR	None	None	Scrubber	Scrubber
01117	ALABAMA POWER COMPANY E C GASTON	26	5	0005	006	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber

APPENDIX I: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE B&F INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
01127	ALABAMA POWER COMPANY GORGAS	8	6	0001	004	Coal Steam	None	None	None	None	None	None	None	None
01127	ALABAMA POWER COMPANY GORGAS	8	7	0001	005	Coal Steam	None	None	None	None	None	None	None	None
01127	ALABAMA POWER COMPANY GORGAS	8	8	0001	006	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
01127	ALABAMA POWER COMPANY GORGAS	8	9	0001	007	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
01127	ALABAMA POWER COMPANY GORGAS	8	10	0001	008	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber
01129	ALABAMA ELECTRIC COOP CHARLES R LOWMAN	56	1	0001	002	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
01129	ALABAMA ELECTRIC COOP CHARLES R LOWMAN	56	2	0001	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
01129	ALABAMA ELECTRIC COOP CHARLES R LOWMAN	56	3	0001	004	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12001	GAINESVILLE REGIONAL UTILITIES JOHN R KELLY	664	JRK6			O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12001	GAINESVILLE REGIONAL UTILITIES JOHN R KELLY	664	JRK7			O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12001	GAINESVILLE REGIONAL UTILITIES JOHN R KELLY	664	JRK8	0010005	7		O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12001	CITY OF GAINESVILLE, GRU DEERHAVEN	663	B1	0010006	3	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12001	CITY OF GAINESVILLE, GRU DEERHAVEN	663	B2	0010006	5	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
12005	GULF POWER COMPANY LANSING SMITH PLANT	643	1	0050014	1	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
12005	GULF POWER COMPANY LANSING SMITH PLANT	643	2	0050014	2	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
12009	FLORIDA POWER & LIGHT (PCC) CAPE CANAVERAL	609	PCC1	0090006	1	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation

APPENDIX I: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE B&F INVENTORY

							Post-Combustion Controls							
FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12009	FLORIDA POWER & LIGHT (PCC) CAPE CANAVERAL	609	PCC2	0090006	2	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE1	0110036	1	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE2	0110036	2	O/G Steam	None	None	None	None	None	None	None	None
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE3	0110036	3	O/G Steam	None	None	None	None	None	None	None	None
12011	FLORIDA POWER & LIGHT (PPE) PORT EVERGLADES	617	PPE4	0110036	4	O/G Steam	None	None	None	None	None	None	None	None
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	1	0170004	1	Coal Steam	None	None	None	None	None	None	None	None
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	2	0170004	2	Coal Steam	None	None	None	None	None	None	None	None
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	5	0170004	3	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
12017	PROGRESS ENERGY FLORIDA CRYSTAL RIVER	628	4	0170004	4	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	SAINT JOHNS RIVER	207	1	0310045-A	16		SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	SAINT JOHNS RIVER	207	2	0310045-A	17		SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	NORTHSIDE	667	2A	0310045-B	26	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12031	NORTHSIDE	667	1A	0310045-B	27	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12031	NORTHSIDE	667	3	0310045-B	3	O/G Steam	None	None	None	No Operation	None	None	None	None
12031	CEDAR BAY COGENERATION INC.	10672	GEN1	0310337	1	Coal Steam	None	SNCR	None	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
12031	CEDAR BAY COGENERATION INC.			0310337	2		None		None					

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12031	CEDAR BAY COGENERATION INC.			0310337	3		None		None					
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	1	0330045	1									
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	2	0330045	2	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	3	0330045	3	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	4	0330045	4	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	5	0330045	5	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	6	0330045	6	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	None	Scrubber	None
12033	GULF POWER COMPANY CRIST ELECTRIC GENERATION	641	7	0330045	7	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber
12053	Central Power and Lime Incorporated	10333	GEN1	0530021	18	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB01	0570039	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB02	0570039	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB03	0570039	3	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY BIG BEND STATION	645	BB04	0570039	4	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB01	0570040	1		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB02	0570040	2		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB03	0570040	3		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB04	0570040	4		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB05	0570040	5		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12057	TAMPA ELECTRIC COMPANY F.J. GANNON STATION	646	GB06	0570040	6		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12061	CITY OF VERO BEACH	693		0610029	1	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12061	CITY OF VERO BEACH	693	3	0610029	3	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12061	CITY OF VERO BEACH	693	4	0610029	4	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12063	GULF POWER COMPANY SCHOLZ	642	1	0630014	1	Coal Steam	None	None	Shut Down	None	None	None	Shut Down	None
12063	GULF POWER COMPANY SCHOLZ	642	2	0630014	2	Coal Steam	None	None	Shut Down	None	None	None	Shut Down	None
12073	CITY OF TALLAHASSEE ARVAH B.HOPKINS	688	1	0730003	1	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12073	CITY OF TALLAHASSEE ARVAH B.HOPKINS	688	2	0730003	4	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12081	FLORIDA POWER & LIGHT (PMT) MANATEE POWER	6042	PMT1	0810010	1	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12081	FLORIDA POWER & LIGHT (PMT) MANATEE POWER	6042	PMT2	0810010	2	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12085	FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	6043	PMR1	0850001	1	O/G Steam	None	None	None	No Operation	None	None	None	No Operation
12085	FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	6043	PMR2	0850001	2	O/G Steam	None	None	None	No Operation	None	None	None	No Operation
12085	INDIANTOWN COGENERATION, L.P.	50976	GEN1	0850102	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12086	FLORIDA POWER & LIGHT (PCU) CUTLER POWER	610	PCU5	0250001	3	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12086	FLORIDA POWER & LIGHT (PCU) CUTLER POWER	610	PCU6	0250001	4	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12086	FLORIDA POWER & LIGHT (PTF) TURKEY POINT	621	PTP1	0250003	1	O/G Steam	None	None	None	No Operation	None	None	None	No Operation
12086	FLORIDA POWER & LIGHT (PTF) TURKEY POINT	621	PTP2	0250003	2	O/G Steam	None	None	None	No Operation	None	None	None	No Operation
12095	ORLANDO UTILITIES COMMISSION STANTON ENERGY	564	1	0950137	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12095	ORLANDO UTILITIES COMMISSION STANTON ENERGY	564	2	0950137	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12099	FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	619	PRV3	0990042	3	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12099	FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	619	PRV4	0990042	4	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12099	CITY OF LAKE WORTH UTILITIES TOM G. SMITH	673	S-1	0990045	7	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12099	CITY OF LAKE WORTH UTILITIES TOM G. SMITH	673	S-3	0990045	9	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12101	PROGRESS ENERGY FLORIDA ANCLOTE	8048	1	1010017	1	O/G Steam	None	None	None	No Operation	None	None	None	No Operation
12101	PROGRESS ENERGY FLORIDA ANCLOTE	8048	2	1010017	2	O/G Steam	None	None	None	No Operation	None	None	None	No Operation
12103	PROGRESS ENERGY FLORIDA BARTOW	634	1	1030011	1	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	No Operation	No Operation
12103	PROGRESS ENERGY FLORIDA BARTOW	634	2	1030011	2	O/G Steam	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12103	PROGRESS ENERGY FLORIDA BARTOW	634	3	1030011	3	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	No Operation	No Operation
12105	LAKELAND ELECTRIC CHARLES LARSEN	675	7	1050003	4	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12105	LAKELAND ELECTRIC C.D. MCINTOSH, JR.	676	3	1050004	1	Coal Steam	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
12105	LAKELAND ELECTRIC C.D. MCINTOSH, JR.	676	3	1050004	5	Coal Steam	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle
12105	LAKELAND ELECTRIC C.D. MCINTOSH, JR.	676	3	1050004	6	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12107	SEMINOLE ELECTRIC COOPERATIVE, INC.	136	1	1070025	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12107	SEMINOLE ELECTRIC COOPERATIVE, INC.	136	2	1070025	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
12111	FT PIERCE UTILITIES AUTHORITY FT PIERCE	658	7	1110003	7	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12111	FT PIERCE UTILITIES AUTHORITY FT PIERCE	658	8	1110003	8	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12121	PROGRESS ENERGY FLORIDA SUWANNEE RIVER	638	1	1210003	1	O/G Steam	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement
12121	PROGRESS ENERGY FLORIDA SUWANNEE RIVER	638	2	1210003	2	O/G Steam	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	None	O/G Early Retirement
12121	PROGRESS ENERGY FLORIDA SUWANNEE RIVER	638	3	1210003	3	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
12127	FLORIDA POWER & LIGHT (PSN) SANFORD POWER	620	PSN3	1270009	1	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
12127	FLORIDA POWER & LIGHT (PSN) SANFORD POWER	620	PSN4	1270009	2		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
12129	TALLAHASSEE CITY PURDOM GENERATING STATION	689	7	1290001	7	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	1BLR	01500011	SG01	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	2BLR	01500011	SG02	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	3BLR	01500011	SG03	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
13015	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	703	4BLR	01500011	SG04	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
13021	ARKWRIGHT	699	1	0002	1		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13021	ARKWRIGHT	699	2	0002	2		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13021	ARKWRIGHT	699	3	0002	3		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13021	ARKWRIGHT	699	4	0002	4		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	1	05100006	SG01	Coal Steam	None	None	None	None	None	None	None	None
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	2	05100006	SG02	Coal Steam	None	None	None	None	None	None	None	None
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	3	05100006	SG03	Coal Steam	None	None	None	SCR	None	None	None	None
13051	SAVANNAH ELECTRIC: KRAFT STEAM	733	4	05100006	SG04	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	11	05100018	11	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	12	05100018	12	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	4	05100018	4	O/G Steam	None	None	None	None	None	None	None	None
13051	RIVERSIDE	734	5	05100018	5	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13051	RIVERSIDE	734	6	05100018	6	O/G Steam	None	No Operation	No Operation	No Operation	None	No Operation	No Operation	No Operation
13067	GEORGIA POWER COMPANY, MCDONOUGH STEAM	710	MB1	06700003	SGM1	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13067	GEORGIA POWER COMPANY, MCDONOUGH STEAM	710	MB2	06700003	SGM2	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y1BR	07700001	SG01	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y2BR	07700001	SG02	Coal Steam	None	None	None	None	None	None	None	None

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y3BR	07700001	SG03	Coal Steam	None	None	None	None	None	None	None	None
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y4BR	07700001	SG04	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y5BR	07700001	SG05	Coal Steam	None	None	SCR	SCR	None	None	None	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y6BR	07700001	SG06	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13077	GEORGIA POWER COMPANY, YATES STEAM-ELECTRIC	728	Y7BR	07700001	SG07	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13095	GEORGIA POWER COMPANY, MITCHELL STEAM-ELECTRIC	727		09500002	SG01		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13095	GEORGIA POWER COMPANY, MITCHELL STEAM-ELECTRIC	727		09500002	SG02		No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13095	GEORGIA POWER COMPANY, MITCHELL STEAM-ELECTRIC	727	3	09500002	SG03	Coal Steam	None	None	None	None	None	None	None	None
13103	SAVANNAH ELECTRIC: MCINTOSH STEAM - ELECTRIC	6124	1	10300003	SG01	Coal Steam	None	None	None	SCR	None	None	None	None
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	1	11500003	SG01	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	2	11500003	SG02	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	3	11500003	SG03	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
13115	GEORGIA POWER COMPANY, HAMMOND STEAM-ELECTRIC	708	4	11500003	SG04	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
13127	GEORGIA POWER COMPANY, MCMANUS STEAM-ELECTRIC	715	1	12700004	SG01	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13127	GEORGIA POWER COMPANY, MCMANUS STEAM-ELECTRIC	715	2	12700004	SG02	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
13149	GEORGIA POWER COMPANY, WANSLEY STEAM-ELECTRIC	6052	1	14900001	SG01	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
13149	GEORGIA POWER COMPANY, WANSLEY STEAM-ELECTRIC	6052	2	14900001	SG02	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	1	20700008	SG01	Coal Steam	None	None	None	None	None	None	Scrubber	None
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	2	20700008	SG02	Coal Steam	None	None	None	None	None	None	Scrubber	None
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	3	20700008	SG03	Coal Steam	None	None	None	None	None	None	Scrubber	None
13207	GEORGIA POWER COMPANY, SCHERER STEAM-ELECTRIC	6257	4	20700008	SG04	Coal Steam	None	None	None	None	None	None	Scrubber	None
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	1	23700008	SG01	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	2	23700008	SG02	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	3	23700008	SG03	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13237	GEORGIA POWER COMPANY, HARLLEE BRANCH	709	4	23700008	SG04	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
13297	GENERIC UNIT	900113	GSC13	ORIS900113	GSC13	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
21015	CINCINNATI GAS & ELECTRIC EAST BEND STAT	6018	2	2101500029	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	1	2104100010	001	Coal Steam	SCR	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	2	2104100010	002	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	3	2104100010	003	Coal Steam	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21041	KENTUCKY UTILITIES CO GHENT GENERATING STATION	1356	4	2104100010	004	Coal Steam	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	1	2104900003	001	Coal Steam	None	None	None	None	None	None	None	None

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							Post-Combustion Controls							
FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	2	2104900003	002	Coal Steam	None	None	None	None	None	None	None	None
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	3	2104900003	003	Coal Steam	None	None	None	None	None	None	None	None
21049	EAST KY POWER COOP WILLIAM C DALE PLANT	1385	4	2104900003	004	Coal Steam	None	None	None	None	None	None	None	None
21059	OWENSBORO MUNICIPAL UTIL ELMER SMITH STATION	1374	1	2105900027	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21059	OWENSBORO MUNICIPAL UTIL ELMER SMITH STATION	1374	2	2105900027	002	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21091	WESTERN KY ENERGY CORP COLEMAN STATION	1381	C1	2109100003	001	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21091	WESTERN KY ENERGY CORP COLEMAN STATION	1381	C2	2109100003	002	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21091	WESTERN KY ENERGY CORP COLEMAN STATION	1381	C3	2109100003	003	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21091	GENERIC UNIT	900121	GSC21	ORIS900121	GSC21	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21101	HENDERSON MUN POW & LIGHT	1372	6	2110100012	002	Coal Steam	None	None	None	None	None	None	None	None
21101	HENDERSON MUN POW & LIGHT	1372	5	2110100012	5	Coal Steam	None	None	None	None	None	None	None	None
21111	LOU GAS & ELEC, CANE RUN	1363	4	0126	04	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, CANE RUN	1363	5	0126	05	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, CANE RUN	1363	6	0126	06	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, MILL CREEK	1364	1	0127	01	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, MILL CREEK	1364	2	0127	02	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21111	LOU GAS & ELEC, MILL CREEK	1364	3	0127	03	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21111	LOU GAS & ELEC, MILL CREEK	1364	4	0127	04	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21127	KENTUCKY POWER CO BIG SANDY PLANT	1353	BSU1	2112700003	001	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
21127	KENTUCKY POWER CO BIG SANDY PLANT	1353	BSU2	2112700003	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	1	2114500006	001	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	2	2114500006	002	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	3	2114500006	003	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	4	2114500006	004	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	5	2114500006	005	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	6	2114500006	006	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	7	2114500006	007	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	8	2114500006	008	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	9	2114500006	009	Coal Steam	None	None	None	None	None	None	None	None
21145	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	1379	10	2114500006	016	Coal Steam	None	None	None	None	None	None	None	None
21161	EAST KY POWER COOP SPURLOCK ST. MAYSVILLE	6041	1	2116100009	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21161	EAST KY POWER COOP SPURLOCK ST. MAYSVILLE	6041	2	2116100009	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber

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							Post-Combustion Controls							
FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21167	KENTUCKY UTILITIES CO BROWN FACILITY	1355	1	2116700001	001	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
21167	KENTUCKY UTILITIES CO BROWN FACILITY	1355	2	2116700001	002	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21167	KENTUCKY UTILITIES CO BROWN FACILITY	1355	3	2116700001	003	Coal Steam	None	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
21177	KENTUCKY UTILITIES CO GREEN RIVER STATION	1357	4	2117700001	003	Coal Steam	None	None	None	None	None	None	None	None
21177	KENTUCKY UTILITIES CO GREEN RIVER STATION	1357	5	2117700001	004	Coal Steam	None	None	None	None	None	None	None	None
21177	TVA PARADISE STEAM PLANT	1378	1	2117700006	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21177	TVA PARADISE STEAM PLANT	1378	2	2117700006	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21177	TVA PARADISE STEAM PLANT	1378	3	2117700006	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21183	WESTERN KY ENERGY CORP WILSON STATION	6823	W1	2118300069	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21199	EAST KY POWER COOP JOHN SHERMAN COOPER	1384	1	2119900005	001	Coal Steam	None	None	None	None	None	None	Scrubber	None
21199	EAST KY POWER COOP JOHN SHERMAN COOPER	1384	2	2119900005	002	Coal Steam	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
21223	LOUISVILLE GAS & ELECTRIC TRIMBLE CO GEN	6071	1	2122300002	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21233	HENDERSON STATION 2	1382	H1	2123300001 -A	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21233	HENDERSON STATION 2	1382	H2	2123300001 -A	003	Coal Steam	SCR	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21233	WESTERN KY ENERGY CORP REID	1383	R1	2123300001 -B	001	Coal Steam	None	None	None	None	None	None	None	None
21233	WESTERN KY ENERGY CORP GREEN STATION	6639	G1	2123300052	001	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
21233	WESTERN KY ENERGY CORP GREEN STATION	6639	G2	2123300052	002	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
21239	KENTUCKY UTILITIES TYRONE FACILITY	1361	5	2123900001	005	Coal Steam	None	None	None	None	None	None	None	None
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051	1	2801100031	001	O/G Steam	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051		2801100031	002		None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051	2	2801100031	003	O/G Steam	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement
28011	ENTERGY MISSISSIPPI INC, DELTA PLANT	2051		2801100031	004		None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement
28019	CHOCTAW GENERATION LLP, RED HILLS GENERATING	55076	AA001	2801900011	001A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
28019	CHOCTAW GENERATION LLP, RED HILLS GENERATING	55076	AA002	2801900011	001B									
28035	MISSISSIPPI POWER COMPANY, PLANT EATON	2046		2803500038	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28035	MISSISSIPPI POWER COMPANY, PLANT EATON	2046		2803500038	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28035	MISSISSIPPI POWER COMPANY, PLANT EATON	2046		2803500038	003	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	1	2804700055	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	2	2804700055	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	3	2804700055	003	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	4	2804700055	004	Coal Steam	None	SCR	SCR	SCR	None	None	None	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
28047	MISSISSIPPI POWER COMPANY, PLANT JACK WATSON	2049	5	2804700055	005	Coal Steam	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
28049	ENTERGY MISSISSIPPI INC, REX BROWN PLANT	2053	4	2804900112	001	O/G Steam	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement
28049	ENTERGY MISSISSIPPI INC, REX BROWN PLANT	2053	3	2804900112	002	O/G Steam	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement
28059	MISSISSIPPI POWER COMPANY, PLANT DANIEL	6073	1	2805900090	001	Coal Steam	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
28059	MISSISSIPPI POWER COMPANY, PLANT DANIEL	6073	2	2805900090	002	Coal Steam	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
28067	MOSELLE SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	2070	1	2806700035	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28067	MOSELLE SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	2070	2	2806700035	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28067	MOSELLE SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	2070	3	2806700035	003	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28073	RD MORROW SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	6061	1	2807300021	001	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
28073	RD MORROW SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	6061	2	2807300021	002	Coal Steam	None	None	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
28075	MISSISSIPPI POWER COMPANY, PLANT SWEATT	2048	1	2807500032	001	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28075	MISSISSIPPI POWER COMPANY, PLANT SWEATT	2048	2	2807500032	002	O/G Steam	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation	No Operation
28083	GREENWOOD UTILITIES, HENDERSON STATION	2062	H1	2808300048	001	O/G Steam	None	None	None	None	No Operation	No Operation	No Operation	No Operation
28083	GREENWOOD UTILITIES, HENDERSON STATION	2062	H3	2808300048	003	O/G Steam	None	None	None	None	No Operation	No Operation	No Operation	No Operation
28149	ENTERGY MISSISSIPPI INC, BAXTER WILSON	2050	1	2814900027	001	O/G Steam	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
28149	ENTERGY MISSISSIPPI INC, BAXTER WILSON	2050	2	2814900027	002	O/G Steam	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement	None	O/G Early Retirement
28151	ENTERGY MISSISSIPPI INC, GERALD ANDRUS	8054	1	2815100048	001	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
28163	YAZOO CITY PUBLIC SERVICE COMMISSION	2067	3	2816300005	001	O/G Steam	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement	O/G Early Retirement
37017	ELIZABETHTOWN POWER, LLC	10380	UNIT1	3701700043	G-17A	Coal Steam	None	None	None	None	None	None	None	None
37017	ELIZABETHTOWN POWER, LLC	10380	UNIT2	3701700043	G-17B		None	None	None	None	None	None	None	None
37019	COGENTRIX OF NORTH CAROLINA INC - SOUTHPORT	10378	GEN1	3701900067	G-29	Coal Steam	None	None	None	None	None	None	None	None
37019	COGENTRIX OF NORTH CAROLINA INC - SOUTHPORT	10378	GEN2	3701900067	G-30	Coal Steam	None	None	None	None	None	None	None	None
37021	CAROLINA POWER & LIGHT ASHEVILLE STEAM	2706	1	628	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37021	CAROLINA POWER & LIGHT ASHEVILLE STEAM	2706	2	628	2	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37025	KANNAPOLIS ENERGY PARTNERS LLC			3702500113	G-2	Coal Steam	None	None	None	None	None	None	None	None
37025	KANNAPOLIS ENERGY PARTNERS LLC			3702500113	G-3	Coal Steam	None	None	None	None	None	None	None	None
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	3	3703500073	G-1	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	4	3703500073	G-2	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	1	3703500073	G-4	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37035	DUKE ENERGY CORPORATION MARSHALL STEAM	2727	2	3703500073	G-5	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37037	PROGRESS ENERGY CAROLINAS CAPE FEAR	2708	5	3703700063	G-1	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Furnace Sorbent Injection	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
37037	PROGRESS ENERGY CAROLINAS CAPE FEAR	2708	6	3703700063	G-2	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Furnace Sorbent Injection	Scrubber
37045	GENERIC UNIT	900137	GSC37	ORIS900137	GSC37	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
37055	GENERIC UNIT	900237	GSC37	ORIS900237	GSC37	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
37055	GENERIC UNIT	900337	GSC37	ORIS900337	GSC37	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
37061	GENERIC UNIT	900437	GSC37	ORIS900437	GSC37	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
37083	GENERIC UNIT	900537	GSC37	ORIS900537	GSC37	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
37083	GENERIC UNIT	900637	GSC37	ORIS900637	GSC37	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	1	3707100039	G-14	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	2	3707100039	G-15	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	3	3707100039	G-16	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	4	3707100039	G-17	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION ALLEN STEAM	2718	5	3707100039	G-18	Coal Steam	SNCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	7	3707100040	G-17	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	8	3707100040	G-18	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	9	3707100040	G-19	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37071	DUKE ENERGY CORPORATION RIVERBEND STEAM	2732	10	3707100040	G-20	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
37083	ROANOKE VALLEY ENERGY FACILITY			3708300174	G-27	Coal Steam	None	None	None	None	None	None	None	None
37083	ROANOKE VALLEY ENERGY FACILITY			3708300174	G-7	Coal Steam	None	None	None	None	None	None	None	None
37129	L V SUTTON STEAM ELECTRIC PLANT	2713	1	3712900036	G-187	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37129	L V SUTTON STEAM ELECTRIC PLANT	2713	2	3712900036	G-188	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
37129	L V SUTTON STEAM ELECTRIC PLANT	2713	3	3712900036	G-189	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	1	3714500029	G-29	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	2	3714500029	G-30	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	3A	3714500029	G-35A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	3B	3714500029	G-35B	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	4A	3714500029	G-36A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - ROXBORO STEAM ELECTRIC PLANT	2712	4B	3714500029	G-36B	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - MAYO FACILITY	6250	1A	3714500045	G-46A	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37145	CP&L - MAYO FACILITY	6250	1B	3714500045	G-46B	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37155	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	2716	1	3715500147	G-24	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37155	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	2716	2	3715500147	G-25	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37155	PROGRESS ENERGY CAROLINAS, INC., W.H. WEATHERSPOON	2716	3	3715500147	G-26	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
37155	LUMBERTON POWER, LLC	10382	UNIT1	3715500166	G-17A	Coal Steam	None	None	None	None	None	None	None	None
37155	LUMBERTON POWER, LLC	10382	UNIT2	3715500166	G-17B		None	None	None	None	None	None	None	None
37157	DUKE ENERGY CORP DAN RIVER STEAM	2723	3	3715700015	G-21	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37157	DUKE ENERGY CORP DAN RIVER STEAM	2723	1	3715700015	G-22	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37157	DUKE ENERGY CORP DAN RIVER STEAM	2723	2	3715700015	G-23	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	5	3715900004	G-1	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	6	3715900004	G-2	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	7	3715900004	G-3	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	8	3715900004	G-4	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37159	DUKE ENERGY CORPORATION BUCK STEAM	2720	9	3715900004	G-5	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	1	3716100028	G-82	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	2	3716100028	G-83	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	3	3716100028	G-84	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	4	3716100028	G-85	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	5	3716100028	G-86	Coal Steam	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
37161	DUKE ENERGY CORPORATION	2721	6	3716100028	G-87	Coal Steam	No Operation	Not in IPM	SCR	Not in IPM	No Operation	Not in IPM	Scrubber	Not in IPM

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
	CLIFFSIDE STEAM													
37161	DUKE ENERGY CORPORATION CLIFFSIDE STEAM	2721	7	3716100028	G-88		No Operation	Not in IPM	No Operation	Not in IPM	No Operation	Not in IPM	No Operation	Not in IPM
37169	DUKE ENERGY CORP BELEWS CREEK STEAM	8042	1	3716900004	G-17	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37169	DUKE ENERGY CORP BELEWS CREEK STEAM	8042	2	3716900004	G-18	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
37191	PROGRESS ENERGY F LEE PLANT	2709	1	3719100017	G-2	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37191	PROGRESS ENERGY F LEE PLANT	2709	2	3719100017	G-3	Coal Steam	None	SNCR	SNCR	SNCR	None	None	None	None
37191	PROGRESS ENERGY F LEE PLANT	2709	3	3719100017	G-4	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	None	Scrubber
45003	SCE&G:URQUHART	3295	URQ3	0080-0011	003	Coal Steam	None	None	None	None	None	None	None	None
45003	SCE&G:SRS AREA D			0080-0044	001	Coal Steam	None	None	None	None	None	None	None	None
45003	SCE&G:SRS AREA D			0080-0044	002		None	None	None	None				
45003	SCE&G:SRS AREA D			0080-0044	003		None	None	None	None				
45003	SCE&G:SRS AREA D			0080-0044	004		None	None	None	None				
45007	DUKE ENERGY:LEE	3264	1	0200-0004	001	Coal Steam	None	None	None	None	None	None	None	None
45007	DUKE ENERGY:LEE	3264	2	0200-0004	002	Coal Steam	None	None	None	None	None	None	None	None
45007	DUKE ENERGY:LEE	3264	3	0200-0004	003	Coal Steam	None	None	None	None	None	None	None	None
45015	SANTEE COOPER JEFFERIES	3319	1	0420-0003	001	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	None	No Operation

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
45015	SANTEE COOPER JEFFERIES	3319	2	0420-0003	002	O/G Steam	No Operation	No Operation	None	No Operation	No Operation	No Operation	None	No Operation
45015	SANTEE COOPER JEFFERIES	3319	3	0420-0003	003	Coal Steam	None	SCR	None	SCR	None	None	None	None
45015	SANTEE COOPER JEFFERIES	3319	4	0420-0003	004	Coal Steam	None	None	None	None	None	None	None	None
45015	SCE&G:WILLIAMS	3298	WIL1	0420-0006	001	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
45015	SANTEE COOPER CROSS	130	1	0420-0030	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45015	SANTEE COOPER CROSS	130	2	0420-0030	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45015	SANTEE COOPER CROSS	130	3	0420-0030	3	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
45015	SANTEE COOPER CROSS	130	4	0420-0030	4	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
45029	SCE&G:CANADYS	3280	CAN1	0740-0002	001	Coal Steam	None	None	None	None	None	None	None	None
45029	SCE&G:CANADYS	3280	CAN2	0740-0002	002	Coal Steam	None	None	None	None	None	None	None	None
45029	SCE&G:CANADYS	3280	CAN3	0740-0002	003	Coal Steam	None	None	None	None	Scrubber	None	Scrubber	None
45031	PROGRESS ENERGY ROBINSON STATION	3251	1	0820-0002	001	Coal Steam	None	None	None	None	None	None	None	None
45043	SANTEE COOPER WINYAH	6249	1	1140-0005	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
45043	SANTEE COOPER WINYAH	6249	2	1140-0005	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
45043	SANTEE COOPER WINYAH	6249	3	1140-0005	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45043	SANTEE COOPER WINYAH	6249	4	1140-0005	004	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
45051	SANTEE COOPER GRAINGER	3317	1	1340-0003	001	Coal Steam	None	None	None	None	None	None	None	None

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
45051	SANTEE COOPER GRAINGER	3317	2	1340-0003	002	Coal Steam	None	None	None	None	None	None	None	None
45063	SCE&G:MCMEEKIN	3287	MCM1	1560-0003	001	Coal Steam	None	None	None	None	None	None	None	None
45063	SCE&G:MCMEEKIN	3287	MCM2	1560-0003	002	Coal Steam	None	None	None	None	None	None	None	None
45075	SCE&G:COPE	7210	COP1	1860-0044	001	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
45079	SCE&G:WATEREE	3297	WAT1	1900-0013	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	None
45079	SCE&G:WATEREE	3297	WAT2	1900-0013	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	Scrubber
45029	GENERIC UNIT	900145	GSC45	ORIS900145	GSC45	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
45031	GENERIC UNIT	900245	GSC45	ORIS900245	GSC45	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
45031	GENERIC UNIT	900345	GSC45	ORIS900345	GSC45	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
45039	GENERIC UNIT	900445	GSC45	ORIS900445	GSC45	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
45043	GENERIC UNIT	900545	GSC45	ORIS900545	GSC45	Coal Steam	No Operation	No Operation	Cross Unit 4	SCR	No Operation	No Operation	Cross Unit 4	Scrubber
47001	TVA BULL RUN FOSSIL PLANT	3396	1	0009	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	1	0007	001	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	2	0007	002	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	3	0007	003	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47073	TVA JOHN SEVIER FOSSIL PLANT	3405	4	0007	004	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	1	0011	001	Coal Steam	None	SCR	SCR	SCR	None	None	None	None

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	2	0011	002	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	3	0011	003	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	4	0011	004	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	5	0011	005	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	6	0011	006	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	7	0011	007	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	8	0011	008	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	9	0011	009	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47085	TVA JOHNSONVILLE FOSSIL PLANT	3406	10	0011	010	Coal Steam	None	SCR	SCR	SCR	None	None	None	None
47145	TVA KINGSTON FOSSIL PLANT	3407	1	0013	001	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	2	0013	002	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	3	0013	003	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	4	0013	004	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	5	0013	005	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	6	0013	006	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	7	0013	007	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
47145	TVA KINGSTON FOSSIL PLANT	3407	8	0013	008	Coal Steam	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber

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							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
47145	TVA KINGSTON FOSSIL PLANT	3407	9	0013	009	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber
47157	ALLEN FOSSIL PLANT	3393	1	00528	Boilr1	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
47157	ALLEN FOSSIL PLANT	3393	2	00528	Boilr2	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
47157	ALLEN FOSSIL PLANT	3393	3	00528	Boilr3	Coal Steam	SCR	SCR	SCR	SCR	None	None	None	None
47161	TVA CUMBERLAND FOSSIL PLANT	3399	1	0011	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
47161	TVA CUMBERLAND FOSSIL PLANT	3399	2	0011	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	1	0025	001	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	2	0025	002	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	3	0025	003	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
47165	TVA GALLATIN FOSSIL PLANT	3403	4	0025	004	Coal Steam	None	None	None	None	None	None	Scrubber	Scrubber
51031	DOMINION - ALTAVISTA POWER STATION	10773	1	00156	1	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
51031	DOMINION - ALTAVISTA POWER STATION	10773	2	00156	2		0	0	0	0	0	0	0	0
51041	DOMINION - CHESTERFIELD POWER STATION	3797	3	00002	3	Coal Steam	None	None	None	None	None	None	Scrubber	None
51041	DOMINION - CHESTERFIELD POWER STATION	3797	4	00002	4	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber
51041	DOMINION - CHESTERFIELD POWER STATION	3797	5	00002	6	Coal Steam	SCR	None	SCR	SCR	None	None	Scrubber	Scrubber
51041	DOMINION - CHESTERFIELD POWER STATION	3797	6	00002	8	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
51065	DOMINION - BREMO POWER STATION	3796	3	00001	1	Coal Steam	None	None	None	None	None	None	None	None

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							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
51065	DOMINION - BREMO POWER STATION	3796	4	00001	2	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	None	None
51071	AMERICAN ELECTRIC POWER GLEN LYN	3776	51	00002	1	Coal Steam	None	None	None	None	None	None	None	None
51071	AMERICAN ELECTRIC POWER GLEN LYN	3776	52	00002	2	Coal Steam	None	None	None	None	None	None	None	None
51071	AMERICAN ELECTRIC POWER GLEN LYN	3776	6	00002	3	Coal Steam	None	None	None	None	None	None	None	Scrubber
51083	DOMINION - CLOVER POWER STATION	7213	1	00046	1	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
51083	DOMINION - CLOVER POWER STATION	7213	2	00046	2	Coal Steam	SNCR	SNCR	SNCR	SNCR	Scrubber	Scrubber	Scrubber	Scrubber
51099	BIRCHWOOD POWER PARTNERS, L.P.	54304	1	00012	1	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
51117	Mecklenburg Cogeneration Facility	52007	GEN1	00051	1	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
51117	Mecklenburg Cogeneration Facility	52007	GEN2	00051	2	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
51153	DOMINION - POSSUM POINT	3804	3	00002	3	Coal Steam	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle
51153	DOMINION - POSSUM POINT	3804	4	00002	4	Coal Steam	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle	None	Combined Cycle
51153	DOMINION - POSSUM POINT	3804	5	00002	5	O/G Steam	None	No Operation	None	No Operation	None	No Operation	None	No Operation
51153	DOMINION - POSSUM POINT	3804	6	00002		Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle
51167	AMERICAN ELECTRIC POWER CLINCH RIVER PLANT	3775	1	00003	1	Coal Steam	None	None	SNCR	SCR	None	None	Emission Cap	Scrubber
51167	AMERICAN ELECTRIC POWER CLINCH RIVER PLANT	3775	2	00003	2	Coal Steam	None	None	SNCR	SCR	None	None	Emission Cap	Scrubber
51167	AMERICAN ELECTRIC POWER CLINCH RIVER PLANT	3775	3	00003	3	Coal Steam	None	None	SNCR	SCR	None	None	Emission Cap	Scrubber

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FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
51175	LG&E Westmoreland Southampton	10774	GEN1	00051	1	Coal Steam	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
51175	LG&E Westmoreland Southampton			00051	2		None	None	None	None	0	0	0	0
51175	LG&E Westmoreland Southampton			00051	4		None	None	None	None	0	0	0	0
51199	DOMINION - YORKTOWN POWER STATION	3809	3	00001	3	O/G Steam	SNCR	No Operation	SNCR	No Operation	None	No Operation	Scrubber	No Operation
51199	DOMINION - YORKTOWN POWER STATION	3809	2	00001	5	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	None
51199	DOMINION - YORKTOWN POWER STATION	3809	1	00001	6	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	None
51510	POTOMAC RIVER GENERATING STATION	3788	1	00003	1	Coal Steam	SNCR	Coal Early Retirement	SNCR	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement
51510	POTOMAC RIVER GENERATING STATION	3788	2	00003	2	Coal Steam	SNCR	Coal Early Retirement	SNCR	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement
51510	POTOMAC RIVER GENERATING STATION	3788	3	00003	3	Coal Steam	SNCR	None	SNCR	None	None	None	None	None
51510	POTOMAC RIVER GENERATING STATION	3788	4	00003	4	Coal Steam	SNCR	None	SNCR	None	None	None	None	None
51510	POTOMAC RIVER GENERATING STATION	3788	5	00003	5	Coal Steam	SNCR	None	SNCR	None	None	None	None	None
51550	DOMINION - CHESAPEAKE	3803	1	00026	1	Coal Steam	SNCR	SNCR	SNCR	SNCR	Low S Coal	None	Scrubber	None
51550	DOMINION - CHESAPEAKE	3803	2	00026	2	Coal Steam	SNCR	SNCR	SNCR	SNCR	Low S Coal	None	Scrubber	None
51550	DOMINION - CHESAPEAKE	3803	3	00026	3	Coal Steam	SCR	None	SCR	SCR	Low S Coal	None	Scrubber	Scrubber
51550	DOMINION - CHESAPEAKE	3803	4	00026	4	Coal Steam	SCR	None	SCR	SCR	Low S Coal	None	Scrubber	Scrubber
51159	GENERIC UNIT	900151	GSC51	ORIS900151	GSC51	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber

APPENDIX I: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE B&F INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
51167	GENERIC UNIT	900251	GSC51	ORIS900251	GSC51	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
51195	GENERIC UNIT	900251	GSC51	ORIS900251	GSC51	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
51175	GENERIC UNIT	900351	GSC51	ORIS900351	GSC51	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
51175	GENERIC UNIT	900451	GSC51	ORIS900451	GSC51	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
51181	GENERIC UNIT	900551	GSC51	ORIS900551	GSC51	Coal Steam	No Operation	No Operation	SCR	SCR	No Operation	No Operation	Scrubber	Scrubber
54023	MOUNT STORM POWER PLANT	3954	1	0003	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54023	MOUNT STORM POWER PLANT	3954	2	0003	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54023	MOUNT STORM POWER PLANT	3954	3	0003	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54023	NORTH BRANCH POWER STATION	7537	1A	0014	001	Coal Steam	None	None	None	None	None	None	None	None
54023	NORTH BRANCH POWER STATION	7537	1B	0014	002	Coal Steam	None	None	None	None	None	None	None	None
54025	WESTERN GREENBRIER			00066	GEN1	Coal Steam	No Operation	No Operation	SCR	No Operation	No Operation	No Operation	SCR	No Operation
54033	MONONGAHELA POWER CO HARRISON	3944	1	0015	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54033	MONONGAHELA POWER CO HARRISON	3944	2	0015	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54033	MONONGAHELA POWER CO HARRISON	3944	3	0015	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54039	APPALACHIAN POWER KANAWHA RIVER PLANT	3936	1	0006	001	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54039	APPALACHIAN POWER KANAWHA RIVER PLANT	3936	2	0006	002	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54049	MONONGAHELA POWER CO. RIVESVILLE POWER	3945	7	0009	001	Coal Steam	None	Coal Early	None	Coal Early	None	Coal Early	Coal Early	Coal Early

APPENDIX I: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE B&F INVENTORY

FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	Post-Combustion Controls							
							VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
								Retirement		Retirement		Retirement	Retirement	Retirement
54049	MONONGAHELA POWER CO. RIVESVILLE POWER	3945	8	0009	002	Coal Steam	None	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54049	AMERICAN BITUMINOUS POWER GRANT TOWN PLT	10151		0026	001		None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
54049	GRANT TOWN POWER PLANT	10151	GEN1	ORIS10151	GEN1	Coal Steam	SNCR	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
54051	OHIO POWER MITCHELL PLANT	3948	1	0005	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54051	OHIO POWER MITCHELL PLANT	3948	2	0005	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54051	OHIO POWER KAMMER PLANT	3947	1	0006	001	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54051	OHIO POWER KAMMER PLANT	3947	2	0006	002	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54051	OHIO POWER KAMMER PLANT	3947	3	0006	003	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	11	0001	001	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	21	0001	002	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	31	0001	003	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	41	0001	004	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER CO. PHILIP SPORN PLANT	3938	51	0001	005	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54053	APPALACHIAN POWER MOUNTAINEER PLANT	6264	1	0009		Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54061	MONONGAHELA POWER CO. FORT MARTIN POWER	3943	1	0001	001	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	Scrubber

APPENDIX I: EGU CONTROLS FOR COAL AND OIL/GAS UNITS FOR THE B&F INVENTORY

							Post-Combustion Controls							
FIPS	Facility Name	ORIS ID	BLR ID	SITE ID	UNIT ID	Plant Type	VISTAS NOx 2009 Controls	IPM NOx 2009 Controls	VISTAS NOx 2018 Controls	IPM NOx 2018 Controls	VISTAS SO2 2009 Controls	IPM SO2 2009 Controls	VISTAS SO2 2018 Controls	IPM SO2 2018 Controls
54061	MONONGAHELA POWER CO. FORT MARTIN POWER	3943	2	0001	002	Coal Steam	SNCR	SNCR	SNCR	SNCR	None	None	Scrubber	Scrubber
54061	MORGANTOWN ENERGY ASSOCIATES			0027	043		None	None	None	None	None	None	None	None
54061	MORGANTOWN ENERGY FACILITY	10743	GEN1	ORIS10743	GEN1	Coal Steam	None	None	None	None	None	None	None	None
54061	LONGVIEW			00134	GEN1	Coal Steam	No Operation	No Operation	SCR	No Operation	No Operation	No Operation	Scrubber	No Operation
54061	GENERIC UNIT	900154	GSC54	ORIS900154	GSC54	Coal Steam	No Operation	No Operation	No Operation	SCR	No Operation	No Operation	No Operation	Scrubber
54073	MONONGAHELA POWER CO. WILLOW ISLAND	3946	1	0004	001	Coal Steam	None	Coal Early Retirement	None	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54073	MONONGAHELA POWER CO. WILLOW ISLAND	3946	2	0004	002	Coal Steam	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
54073	MONONGAHELA POWER CO PLEASANTS POWER STATION	6004	1	0005	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
54073	MONONGAHELA POWER CO PLEASANTS POWER STATION	6004	2	0005	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber Upgrade	Scrubber	Scrubber Upgrade	Scrubber
54077	MONONGAHELA POWER CO ALBRIGHT	3942	1	0001	001	Coal Steam	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54077	MONONGAHELA POWER CO ALBRIGHT	3942	2	0001	002	Coal Steam	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement	None	Coal Early Retirement	Coal Early Retirement	Coal Early Retirement
54077	MONONGAHELA POWER CO ALBRIGHT	3942	3	0001	003	Coal Steam	None	None	SCR	SCR	None	None	Scrubber	Scrubber
54079	APPALACHIAN POWER JOHN E AMOS PLANT	3935	1	0006	001	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54079	APPALACHIAN POWER JOHN E AMOS PLANT	3935	2	0006	002	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
54079	APPALACHIAN POWER JOHN E AMOS PLANT	3935	3	0006	003	Coal Steam	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber

Weight of Evidence

E2: TSD Version IV 042508

"With CAIR"

Link to:

http://www.epa.ohio.gov/portals/27/SIP/Attain/E2_TSD_Version_IV_April_25_2008_FINAL.pdf

Regional Air Quality Analyses for Ozone, $PM_{2.5}$, and Regional Haze:

Final Technical Support Document

April 25, 2008

States of Illinois, Indiana, Michigan, Ohio, and Wisconsin

Table of Contents

EXECUTIVE SUMMARY

States in the upper Midwest face a number of air quality challenges. More than 50 counties are currently classified as nonattainment for the 8-hour ozone standard and 60 for the fine particle ($PM_{2.5}$) standard (1997 versions). A map of these nonattainment areas is provided in the figure below. In addition, visibility impairment due to regional haze is a problem in the larger national parks and wilderness areas (i.e., Class I areas). There are 156 Class I areas in the U.S., including two in northern Michigan.

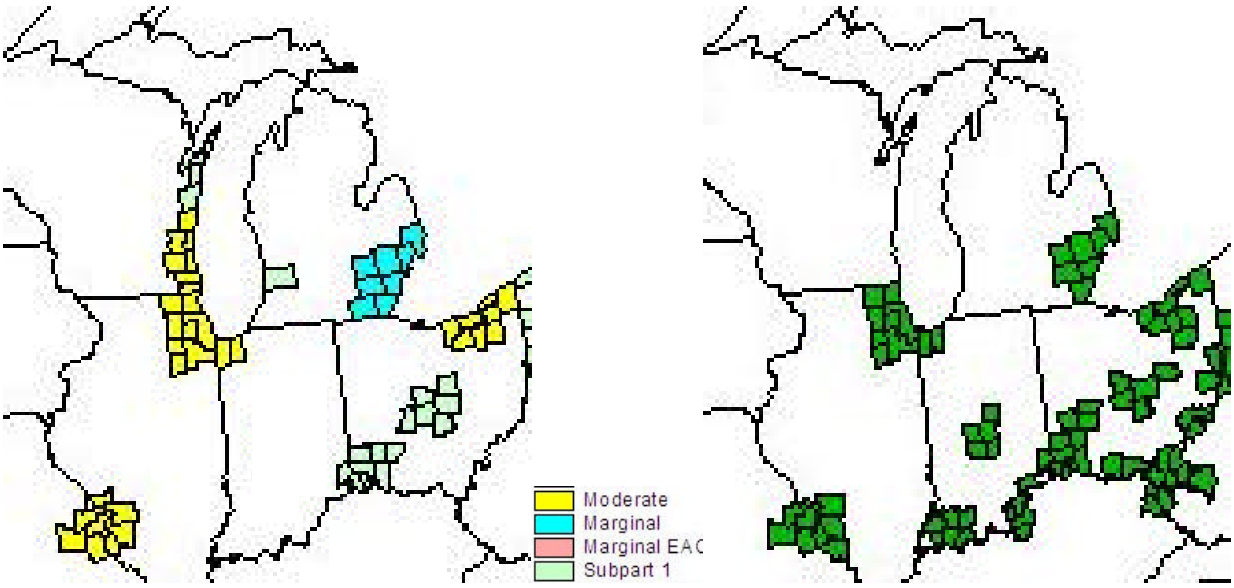


Figure i. Current nonattainment counties for ozone (left) and $PM_{2.5}$ (right)

To support the development of State Implementation Plans (SIPs) for ozone, $PM_{2.5}$, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin, technical analyses were conducted by the Lake Michigan Air Directors Consortium (LADCO), its member states, and various contractors. The analyses include preparation of regional emissions inventories and meteorological data, evaluation and application of regional chemical transport models, and collection and analysis of ambient monitoring data.

Monitoring data were analyzed to produce a conceptual understanding of the air quality problems. Key findings of the analyses include:

Ozone

- Current monitoring data (2005-2007) show about 20 sites in violation of the 8-hour ozone standard of 85 parts per billion (ppb). Historical ozone data show a steady downward trend over the past 15 years, especially since 2001-2003, due likely to federal and state emission control programs.

- Ozone concentrations are strongly influenced by meteorological conditions, with more high ozone days and higher ozone levels during summers with above normal temperatures.

- Inter- and intra-regional transport of ozone and ozone precursors affects many portions of the five states, and is the principal cause of nonattainment in some areas far from population or industrial centers.

$PM_{2.5}$

- Current monitoring data (2005-2007) show 30 sites in violation of the annual $PM_{2.5}$ standard of 15 ug/m^3. Nonattainment sites are characterized by an elevated regional background (about 12 – 14 ug/m^3) and a significant local (urban) increment (about 2 – 3 ug/m^3). Historical $PM_{2.5}$ data show a slight downward trend since deployment of the $PM_{2.5}$ monitoring network in 1999.

- $PM_{2.5}$ concentrations are also influenced by meteorology, but the relationship is more complex and less well understood compared to ozone.

- On an annual average basis, $PM_{2.5}$ chemical composition consists mostly of sulfate, nitrate, and organic carbon in similar proportions.

Haze

- Current monitoring data (2000-2004) show visibility levels in the Class I areas in northern Michigan are on the order of 22 – 24 deciviews. The goal of EPA's visibility program is to achieve natural conditions, which is about 12 deciviews for these Class I areas, by the year 2064.

- Visibility impairment is dominated by sulfate and nitrate.

Air quality models were applied to support the regional planning efforts. Two base years were used in the modeling analyses: 2002 and 2005. Basecase modeling was conducted to evaluate model performance (i.e., assess the model's ability to reproduce observed concentrations). This exercise was intended to build confidence in the model prior to its use in examining control strategies. Model performance for ozone and $PM_{2.5}$ was found to be generally acceptable.

Future year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Based on the modeling and other supplemental analyses, the following general conclusions can be made:

- Existing controls are expected to produce significant improvement in ozone and $PM_{2.5}$ concentrations and visibility levels.

- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).

- Modeling suggests that most sites are expected to meet the current 8-hour ozone standard by the applicable attainment date, except for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.

- Modeling suggests that most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.

  The regional modeling for $PM_{2.5}$ does not include air quality benefits expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$.

- These findings of residual nonattainment for ozone and $PM_{2.5}$ are supported by current (2005 – 2007) monitoring data which show significant nonattainment in the region (e.g., peak ozone design values on the order of 90 – 93 ppb, and peak $PM_{2.5}$ design values on the order of 16 - 17 ug/m^3). It is unlikely that sufficient emission reductions will occur in the next couple of years to provide for attainment at all sites.

- Attainment at most sites by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). If either of these conditions is not met, then attainment may be less likely.

- Modeling suggests that the new $PM_{2.5}$ 24-hour standard and the new lower ozone standard will not be met at several sites, even by 2018, with existing controls.

- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018 based on existing controls, including those in northern Michigan and some in the northeastern U.S. Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018. These results, along with information on the costs of compliance, time necessary for compliance, energy and non air quality environmental impacts of compliance, and remaining useful life of existing sources, should be considered by the states in setting reasonable progress goals for regional haze.

Section 1.0 Introduction

This Technical Support Document summarizes the final air quality analyses conducted by the Lake Michigan Directors Consortium (LADCO)[1] and its contractors to support the development of State Implementation Plans (SIPs) for ozone, fine particles ($PM_{2.5}$), and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin. The analyses include preparation of regional emissions inventories and meteorological modeling data for two base years (2002 and 2005), evaluation and application of regional chemical transport models, and analysis of ambient monitoring data.

Two aspects of the analyses should be emphasized. First, a regional, multi-pollutant approach was taken in addressing ozone, $PM_{2.5}$, and haze for technical reasons (e.g., commonality in precursors, emission sources, atmospheric processes, transport influences, and geographic areas of concern), and practical reasons (e.g., more efficient use of program resources). Furthermore, EPA has consistently encouraged multi-pollutant planning in its rule for the haze program (64 FR 35719), and its implementation guidance for ozone (70 FR 71663) and $PM_{2.5}$ (72 FR 20609). Second, a weight-of-evidence approach was taken in considering the results of the various analyses (i.e., two sets of modeling results -- one for a 2002 base year and one for a 2005 base year -- and ambient data analyses) in order to provide a more robust assessment of expected future year air quality.

The report is organized in the following sections. This Introduction provides an overview of regulatory requirements and background information on regional planning. Section 2 reviews the ambient monitoring data and presents a conceptual model of ozone, $PM_{2.5}$, and haze for the region. Section 3 discusses the air quality modeling analyses, including development of the key model inputs (emissions inventory and meteorological data), and basecase model performance evaluation. A modeled attainment demonstration for ozone and $PM_{2.5}$ is presented in Section 4, along with relevant data analyses considered as part of the weight-of-evidence determination. Section 5 documents the reasonable progress assessment for regional haze, along with relevant data analyses considered as part of the weight-of-evidence determination. Finally, key study findings are reviewed and summarized in Section 6.

1.1 SIP Requirements

For ozone, EPA promulgated designations on April 15, 2004 (69 FR 23858, April 30, 2004). In the 5-state region, more than 100 counties were designated as nonattainment.[2] The designations became effective on June 15, 2004. SIPs for ozone were due no later than three years from the effective date of the nonattainment designations (i.e., by June 2007). The attainment date for ozone varies as a function of nonattainment classification. For the region, the attainment dates are either June 2007 (marginal nonattainment areas), June 2009 (basic nonattainment areas), or June 2010 (moderate nonattainment areas).

[1] A sub-entity of LADCO, known as the Midwest Regional Planning Organization (MRPO), is responsible for the regional haze activities of the multi-state organization.

[2] Based on more recent air quality data, many counties in Indiana, Michigan, and Ohio were subsequently redesignated as attainment. As of December 31, 2007, there are 53 counties designated as nonattainment in the region.

For $PM_{2.5}$, EPA promulgated designations on December 17, 2004 (70 FR 944, January 5, 2005). In the 5-state region, 70 counties were designated as nonattainment.[3] The designations became effective on April 5, 2005. SIPs for $PM_{2.5}$ are due no later than three years from the effective date of the nonattainment designations (per section 172(b) of the Clean Air Act) (i.e., by April 2008) and for haze no later than three years after the date on which the Administrator promulgated the $PM_{2.5}$ designations (per the Omnibus Appropriations Act of 2004) (i.e., by December 2007). The applicable attainment date for $PM_{2.5}$ nonattainment areas is five years from the date of the nonattainment designation (i.e., by April 2010).

For haze, the Clean Air Act sets "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." There are 156 Class I areas, including two in northern Michigan: Isle Royale National Park and Seney National Wildlife Refuge[4]. EPA's visibility rule (64 FR 35714, July 1, 1999) requires reasonable progress in achieving "natural conditions" by the year 2064. As noted above, the first regional haze SIP was due in December 2007 and must address the initial 10-year implementation period (i.e., reasonable progress by the year 2018). SIP requirements (pursuant to 40 CFR 51.308(d)) include setting reasonable progress goals, determining baseline conditions, determining natural conditions, providing a long-term control strategy, providing a monitoring strategy (air quality and emissions), and establishing BART emissions limitations and associated compliance schedule.

1.2 Organization

LADCO was established by the States of Illinois, Indiana, Michigan, and Wisconsin in 1989. The four states and EPA signed a Memorandum of Agreement (MOA) that initiated the Lake Michigan Ozone Study (LMOS) and identified LADCO as the organization to oversee the study. Additional MOAs were signed by the States in 1991 (to establish the Lake Michigan Ozone Control Program), January 2000 (to broaden LADCO's responsibilities), and June 2004 (to update LADCO's mission and reaffirm the commitment to regional planning). In March 2004, Ohio joined LADCO. LADCO consists of a Board of Directors (i.e., the State Air Directors), a technical staff, and various workgroups. The main purposes of LADCO are to provide technical assessments for and assistance to its member states, and to provide a forum for its member states to discuss regional air quality issues.

MRPO is a similar entity led by the five LADCO States and involves the federally recognized tribes in Michigan and Wisconsin, EPA, and Federal Land Managers (i.e., National Park Service, U.S. Fish & Wildlife Agency, and U.S. Forest Service). In October 2000, the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin signed an MOA that established the MRPO. An operating principles document for MRPO, which describe the roles and responsibilities of states, tribes, federal agencies, and stakeholders, was issued in March 2001. MRPO has a similar purpose as LADCO, but is focused on visibility impairment due to regional haze in the Federal Class I areas located inside the borders of the five states, and the impact of emissions from the five states on visibility impairment due to regional haze in the Federal Class I areas located outside the borders of the five states. MRPO works cooperatively with the Regional Planning Organizations (RPOs) representing other parts of the country. The RPOs sponsored several

[3] USEPA subsequently adjusted the final designations, which resulted in 63 counties in the region being designated as nonattainment (70 FR 19844, April 15, 2005).

[4] Although Rainbow Lake in northern Wisconsin is also a Class I area, the visibility rule does not apply because the Federal Land Manager determined that visibility is not an air quality related value there.

joint projects and, with assistance by EPA, maintain regular contact on technical and policy matters.

1.3 Technical Work: Overview

To ensure the reliability and effectiveness of its planning process, LADCO has made data collection and analysis a priority. More than $7M in RPO grant funds were used for special purpose monitoring, preparing and improving emissions inventories, and conducting air quality analyses[5]. An overview of the technical work is provided below.

Monitoring: Numerous monitoring projects were conducted to supplement on-going state and local air pollution monitoring. These projects include rural monitoring (e.g., comprehensive sampling in the Seney National Wildlife Refuge and in Bondville, IL); urban monitoring (e.g., continuation of the St. Louis Supersite); aloft (aircraft) measurements; regional ammonia monitoring; and organic speciation sampling in Seney, Bondville, and five urban areas.

Emissions: Baseyear emissions inventories were prepared for 2002 and 2005. States provided point source and area source emissions data, and MOBILE6 input files and mobile source activity data. LADCO and its contractors developed the emissions data for other source categories (e.g., select nonroad sources, ammonia, fires, and biogenics) and processed the data for input into an air quality model. To support control strategy modeling, future year inventories were prepared. The future years of interest include 2008 (planning year to address the 2009 attainment year for basic ozone nonattainment ares), 2009 (planning year to address the 2010 attainment year for $PM_{2.5}$ and moderate ozone nonattainment areas), 2012 (planning to address a 2013 alternative attainment date), and 2018 (first milestone year for regional haze).

Air Quality Analyses: The weight-of-evidence approach relies on data analysis and modeling. Air quality data analyses were used to provide both a conceptual model (i.e., a qualitative description of the ozone, $PM_{2.5}$, and regional haze problems) and supplemental information for the attainment demonstration. Given uncertainties in emissions inventories and modeling, especially for $PM_{2.5}$, these data analyses are a necessary part of the overall technical support.

Modeling includes baseyear analyses for 2002 and 2005 to evaluate model performance and future year strategy analyses to assess candidate control strategies. The analyses were conducted in accordance with EPA's modeling guidelines (EPA, 2007a). The PM/haze modeling covers the full calendar year (2002 and 2005) for an eastern U.S. 36 km domain, while the ozone modeling focuses on the summer period (2002 and 2005) for a Midwest 12 km subdomain. The same model (CAMx) was used for ozone, $PM_{2.5}$, and regional haze.

[5] Since 1999, MRPO has received almost $10M in RPO grant funds from USEPA.

Section 2.0 Ambient Data Analyses

An extensive network of air quality monitors in the 5-state region provides data for ozone (and its precursors), $PM_{2.5}$ (both total mass and individual chemical species), and visibility. These data are used to determine attainment/nonattainment designations, support SIP development, and provide air quality information to public (see, for example, www.airnow.gov).

Analyses of the data were conducted to produce a conceptual model, which is a qualitative summary of the physical, chemical, and meteorological processes that control the formation and distribution of pollutants in a given region. This section reviews the relevant data analyses and describes our understanding of ozone, $PM_{2.5,}$ and regional haze with respect to current conditions, data variability (spatial, temporal, and chemical), influence of meteorology (including transport patterns), precursor sensitivity, and source culpability.

2.1 Ozone

In 1979, EPA adopted an ozone standard of 0.12 ppm, averaged over a 1-hour period. This standard is attained when the number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is equal to or less than 1.0, averaged over a 3-year period, which generally reflects a design value (i.e., the 4th highest daily 1-hour value over a 3-year period) less than 0.12 ppm.

In 1997, EPA tightened the ozone standard to 0.08 ppm, averaged over an 8-hour period[6]. The standard is attained if the 3-year average of the 4th-highest daily maximum 8-hour average ozone concentrations (i.e., the design value) measured at each monitor within an area is less than 0.08 ppm (or 85 ppb).

Current Conditions: A map of the 8-hour ozone design values at each monitoring site in the region for the 3-year period 2005-2007 is shown in Figure 1. The "hotter" colors represent higher concentrations, where yellow and orange dots represent sites with design values above the standard. Currently, there are 19 sites in violation of the 8-hour ozone NAAQS in the 5-state region, including sites in the Lake Michigan area, Detroit, Cleveland, Cincinnati, and Columbus.

Table 1 provides the 4th-highest daily 8-hour ozone values and the associated design values since 2001 for several high monitoring sites throughout the region.

[6] On March 12, 2008, USEPA further tightened the 8-hour ozone standard to increase public health protection and prevent environmental damage from ground-level ozone. USEPA set the primary (health) standard and secondary (welfare) standard at the same level: 0.075 ppm (75 ppb), averaged over an 8-hour period.

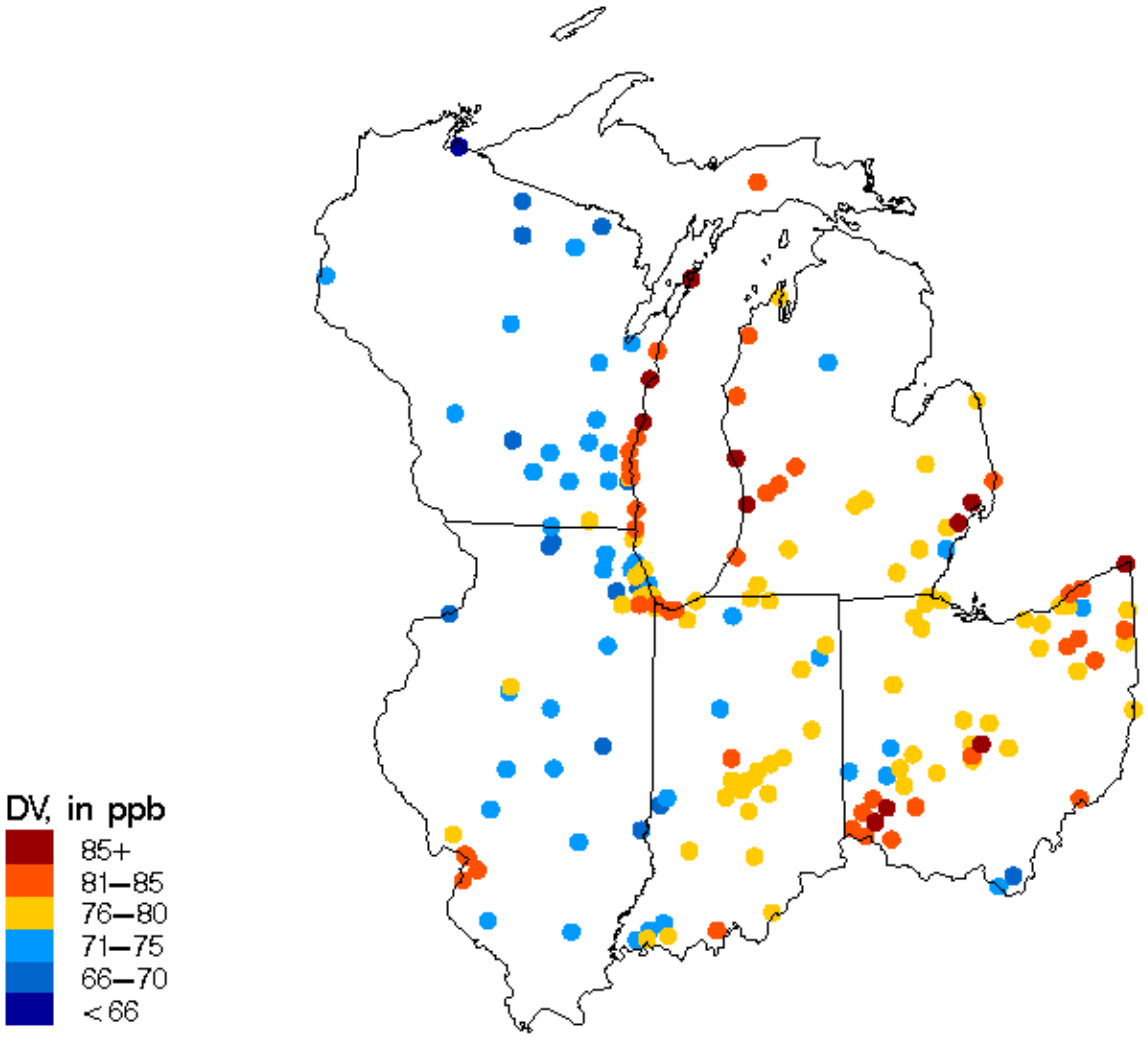


Figure 1. 8-hour ozone design values (2005-2007)

Table 1. Ozone Data for Select Sites in 5-State Region

Key Sites	4th High 8-hour Value								Design Values				
	'01	'02	'03	'04	'05	'06	'07		'01-'03	'02-'04	'03-'05	'04-'06	'05-'07
Lake Michigan Area													
Chiwaukee	99	116	88	78	93	79	85		**101**	**94**	**86**	83	**85**
Racine	92	111	82	69	95	71	77		**95**	**87**	82	78	81
Milwaukee-Bayside	93	99	92	73	93	73	83		**94**	**88**	**86**	79	83
Harrington Beach	102	93	99	72	94	72	84		**98**	**88**	**88**	79	83
Manitowoc	97	83	92	74	95	78	85		**90**	83	**87**	82	**86**
Sheboygan	102	105	93	78	97	83	88		**100**	**92**	**89**	**86**	**89**
Kewaunee	90	92	97	73	88	76	85		**93**	**87**	**86**	*79*	83
Door County	95	95	93	78	101	79	92		**94**	**88**	**90**	**86**	**90**
Hammond	90	101	81	67	87	75	77		**90**	83	78	76	79
Whiting				64	88	81	88					77	**85**
Michigan City	90	107	82	70	84	75	73		**93**	**86**	78	76	77
Ogden Dunes	85	101	77	69	90	70	84		**87**	82	78	76	81
Holland	92	105	96	79	94	91	94		**97**	**93**	**89**	**88**	**93**
Jenison	86	93	91	69	86	83	88		**90**	84	82	79	**85**
Muskegon	95	96	94	70	90	90	86		**95**	**86**	84	83	**88**
Indianapolis Area													
Noblesville	88	101	101	75	87	77	84		**96**	**92**	**87**	79	82
Fortville	89	101	92	72	80	75	81		**94**	**88**	81	75	78
Fort B. Harrison	87	100	91	73	80	76	83		**92**	**88**	81	76	79
Detroit Area													
New Haven	95	95	102	81	88	78	93		**97**	**92**	**90**	82	**86**
Warren	94	92	101	71	89	78	91		**95**	**88**	**87**	79	**86**
Port Huron	84	100	87	74	88	78	89		**90**	**87**	83	80	**85**
Cleveland Area													
Ashtabula (Conneaut)	97	103	99	81	93	86	92		**99**	**94**	**91**	**86**	**90**
Notre Dame (Geauga)	99	115	97	75	88	70	68		**103**	**95**	**86**	77	75
Eastlake (Lake)	89	104	92	79	97	83	74		**95**	**91**	**89**	**86**	84
Akron (Summit)	98	103	89	77	89	77	91		**96**	**89**	**85**	81	**85**
Cincinnati Area													
Wilmington (Clinton)	93	99	96	78	83	81	82		**96**	**91**	**85**	80	82
Sycamore (Hamilton)	88	100	93	76	89	81	90		**93**	**89**	**86**	82	**86**
Hamilton (Butler)	83	100	94	75	86	79	91		**92**	**89**	**85**	80	**85**
Middleton (Butler)	87	98	83	76	88	76	91		**89**	**85**	82	80	**85**
Lebanon (Warren)	85	98	95	81	92	86	88		**92**	**91**	**89**	**86**	**88**
Columbus Area													
London (Madison)	84	97	90	75	81	76	83		**90**	**87**	82	77	80
New Albany (Franklin)	90	103	94	78	92	82	87		**95**	**91**	**88**	84	**87**
Franklin (Franklin)	83	99	84	73	86	79	79		**88**	**85**	81	79	81
Ohio Other Areas													
Marietta (Washington)	85	95	80	77	88	81	86		**86**	84	81	82	**85**
St. Louis Area													
W. Alton (MO)	85	99	91	77	89	91	89		**91**	**89**	**85**	**85**	**89**
Orchard (MO)	88	98	90	76	92	92	83		**92**	**88**	**86**	**86**	**89**
Sunset Hills (MO)	88	98	88	70	89	80	89		**91**	**85**	82	79	**86**
Arnold (MO)	86	93	82	70	92	79	87		**87**	81	81	80	**86**
Margaretta (MO)	80	98	90	72	91	76	91		**89**	**86**	84	79	**86**
Maryland Heights (MO)					88	84	94						**88**

Meteorology and Transport: Most pollutants exhibit some dependence on meteorological factors, especially wind direction, because that governs which sources are upwind and thus most influential on a given sample. Ozone is even more dependent, since its production is driven by high temperatures and sunlight, as well as precursor concentrations (see, for example, Figure 2).

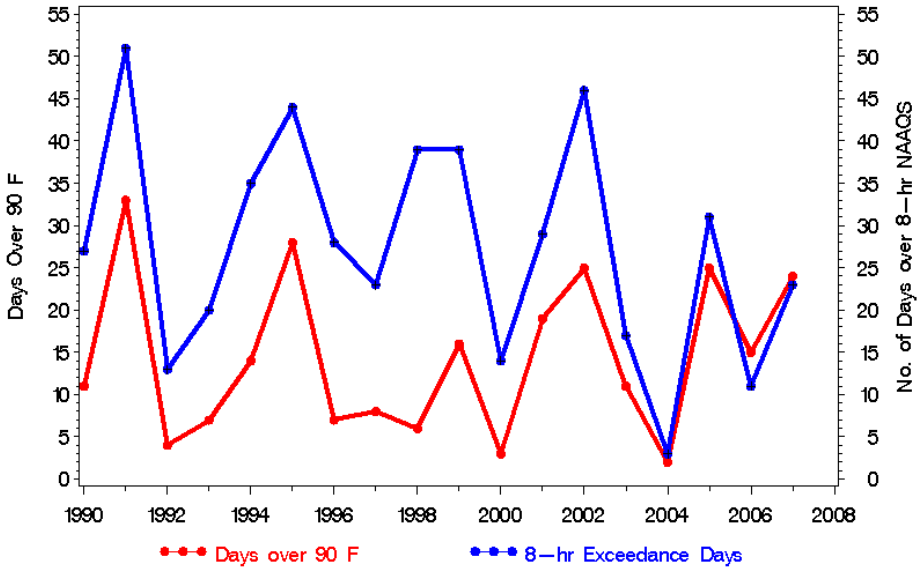


Figure 2. Number of hot days and 8-hour "exceedance" days in 5-state region

Qualitatively, ozone episodes in the region are associated with hot weather, clear skies (sometimes hazy), low wind speeds, high solar radiation, and southerly to southwesterly winds. These conditions are often a result of a slow-moving high pressure system to the east of the region. The relative importance of various meteorological factors is discussed later in this section.

Transport of ozone (and its precursors) is a significant factor and occurs on several spatial scales. Regionally, over a multi-day period, somewhat stagnant summertime conditions can lead to the build-up in ozone and ozone precursor concentrations over a large spatial area. This pollutant air mass can be advected long distances, resulting in elevated ozone levels in locations far downwind. An example of such an episode is shown in Figure 3.

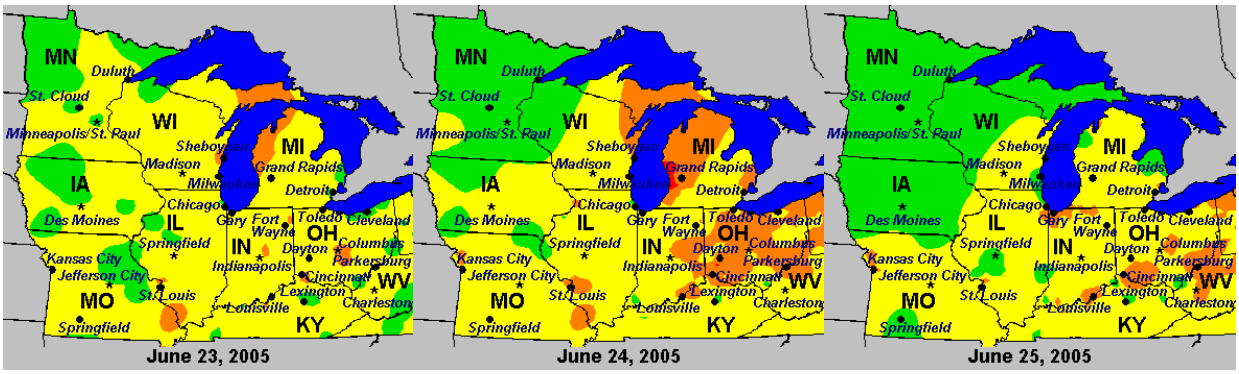


Figure 3. Example of elevated regional ozone concentrations (June 23 – 25, 2005)

Note: hotter colors represent higher concentrations, with orange representing concentrations above the 8-hour standard

Locally, emissions from urban areas add to the regional background leading to ozone concentration hot spots downwind. Depending on the synoptic wind patterns (and local land-lake breezes), different downwind areas are affected (see, for example, Figure 4).

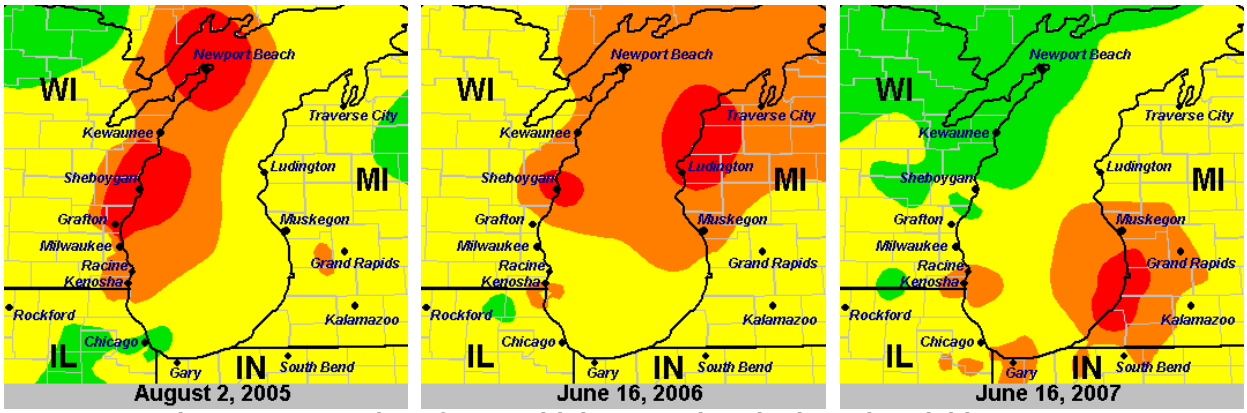


Figure 4. Examples of recent high ozone days in the Lake Michigan area

Note: hotter colors represent higher concentrations, with orange representing concentrations above the 8-hour standard

Aloft (aircraft) measurements in the Lake Michigan area also provide evidence of elevated regional background concentrations and "plumes" from urban areas. For one example summer day (August 20, 2003 – see Figure 5), the incoming background ozone levels were on the order of 80 – 100 ppb and the downwind ozone levels over Lake Michigan were on the order of 100 - 150 ppb (STI, 2004).

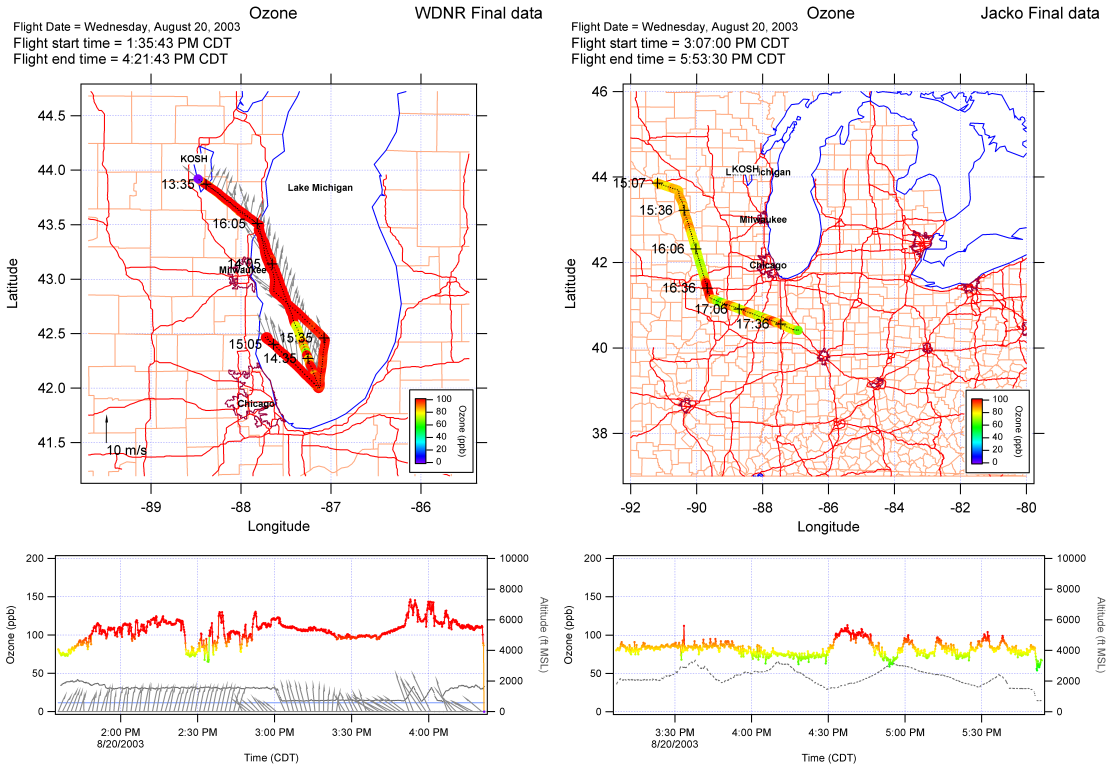


Figure 5. Aircraft ozone measurements over Lake Michigan (left) and along upwind boundary (right) – August 20, 2003 (Note: aircraft measurements reflect instantaneous values)

As discussed in Section 4, residual nonattainment is projected in at least one area in the 5-state region –i.e., western Michigan. To understand the source regions likely impacting high ozone concentrations in western Michigan and estimate the impact of these source regions, two simple transport-related analyses were performed.

First, back trajectories were constructed using the HYSPLIT model for high ozone days (8-hour peak > 80 ppb) during the period 2002-2006 in western Michigan to characterize general transport patterns. Composite trajectory plots for all high ozone days based on data from three sites (Cass County, Holland, and Muskegon) are provided in Figure 6. The plots point back to areas located to the south-southwest (especially, northeastern Illinois and northwestern Indiana) as being upwind on these high ozone days.

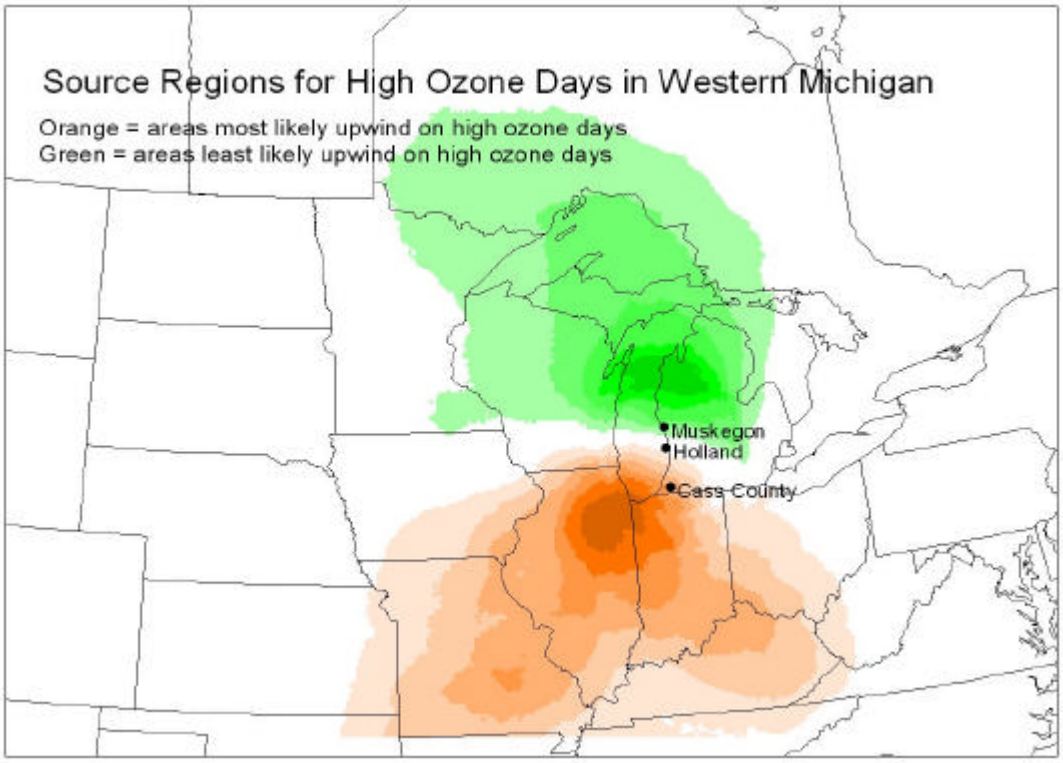


Figure 6 Back trajectory analysis showing upwind areas associated with high ozone concentrations

Second, to assess the impact from Chicago/NW Indiana, Blanchard (2005a) compared ozone concentrations upwind (Braidwood, IL), within Chicago (ten sites in the City), and downwind (Holland and Muskegon) for days in 1999 – 2002 with southwesterly winds - i.e., transport towards western Michigan. Figure 7 shows the distribution of daily peak 8-hour ozone concentrations by day-of-week, with a line connecting the mean values. The difference between day-of-week mean values at downwind and upwind sites indicates that Chicago/NW Indiana contributes about 10-15 ppb to downwind ozone levels.

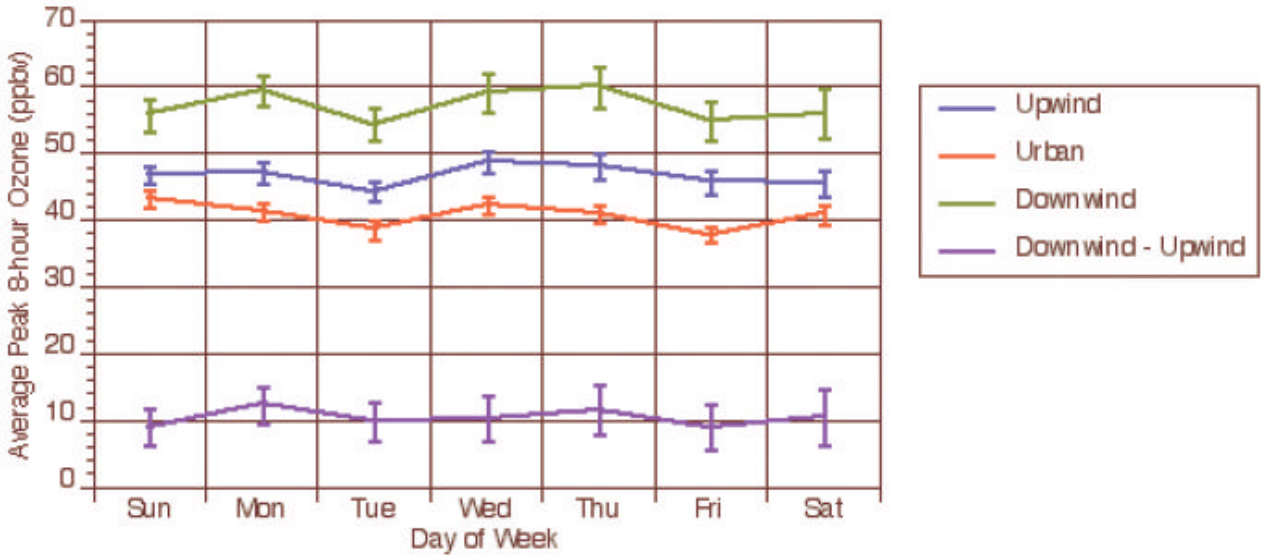


Figure 7. Mean day-of-week peak 8-hour ozone concentrations at sites upwind, within, and downwind of Chicago, 1999 – 2002 (southwesterly wind days)

Based on this information, the following key findings related to transport can be made:

- Ozone transport is a problem affecting many portions of the eastern U.S. The Lake Michigan area (and other areas in the LADCO region) both receive high levels of incoming (transported) ozone and ozone precursors from upwind source areas on many hot summer days, and contribute to the high levels of ozone and ozone precursors affecting downwind receptor areas.

- The presence of a large body of water (i.e., Lake Michigan) influences for the formation and transport of ozone in the Lake Michigan area. Depending on large-scale synoptic winds and local-scale lake breezes, different parts of the area experience high ozone concentrations. For example, under southerly flow, high ozone can occur in eastern Wisconsin, and under southwesterly flow, high ozone can occur in western Michigan.

- Downwind shoreline areas around Lake Michigan are affected by both regional transport of ozone and subregional transport from major cities in the Lake Michigan area. Counties along the western shore of Michigan (from Benton Harbor to Traverse City, and even as far north as the Upper Peninsula) are impacted by high levels of incoming (transported) ozone.

Data Variability: Since 1980, considerable progress has been made to meet the previous 1-hour ozone standard. Figure 8 shows the decline in both the 1-hour and 8-hour design values for the 5-state LADCO region over the last 25 years.

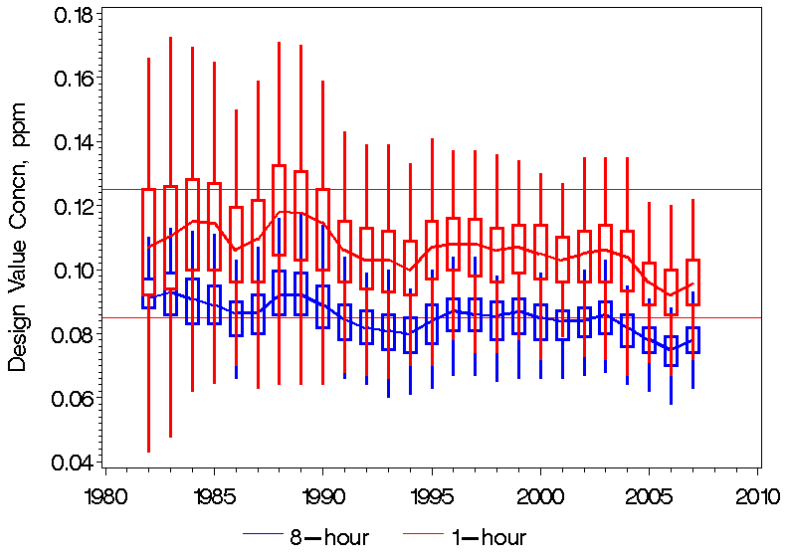


Figure 8 Ozone design value trends in 5-State region

The trend is more dramatic for the higher ozone sites in the 5-state region (see Figure 9). This plot shows a pronounced downward trend in the design value since the 2001-2003 period, due, in part, to the very low 4th high values in 2004.

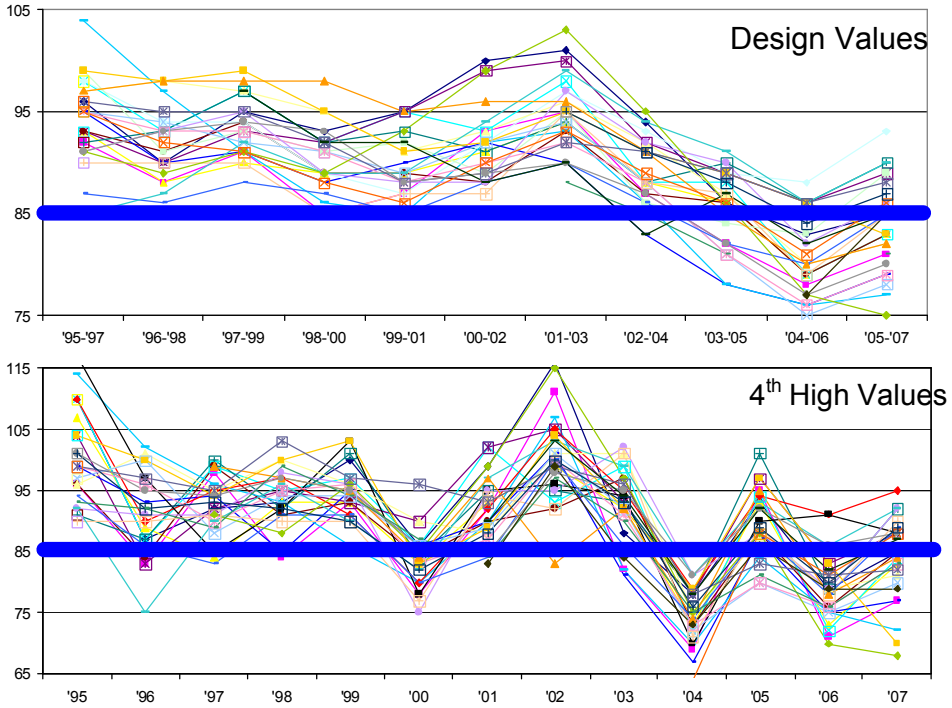


Figure 9. Trend in ozone design values and 4th high values for higher ozone sites in region

The improvement in ozone concentrations is also seen in the decrease in the number of sites measuring nonattainment over the past 15 years in the Lake Michigan area (see Figure 10).

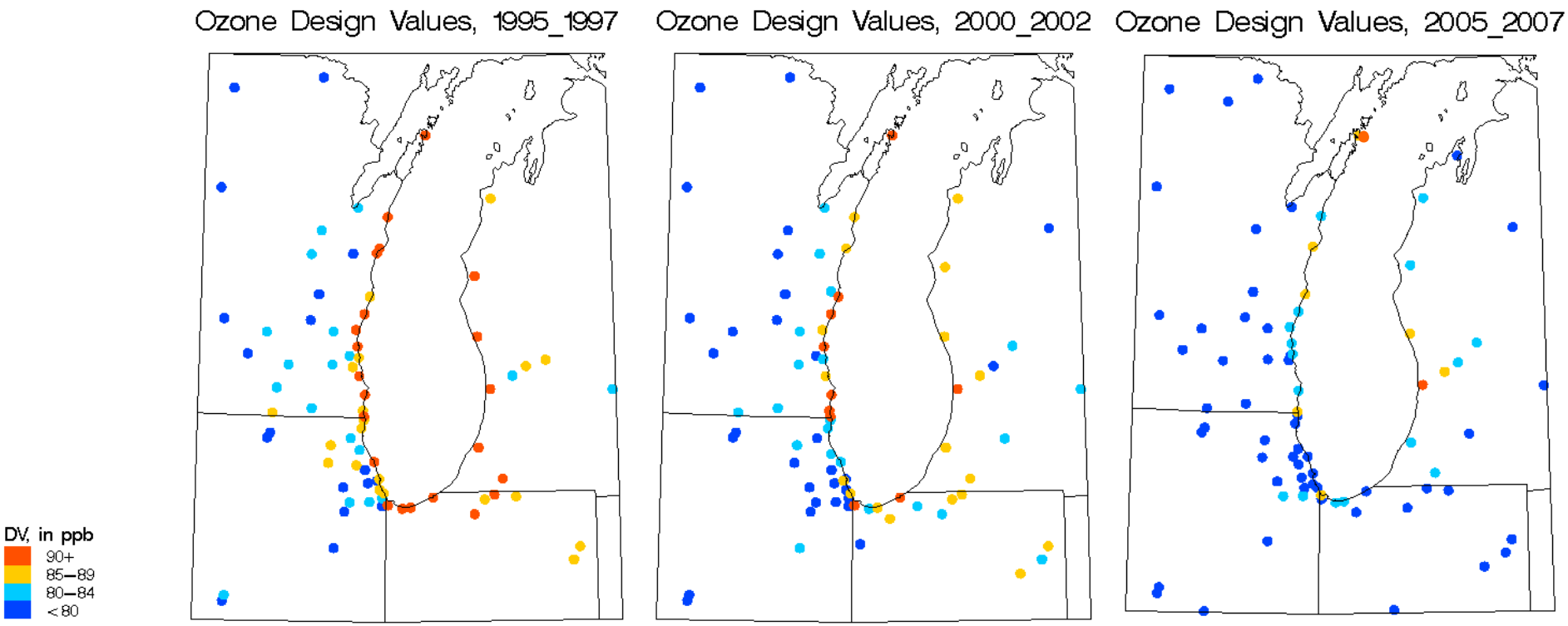


Figure 10. Ozone design value maps for 1995-1997, 2000-2002, and 2005-2007

Given the effect of meteorology on ambient ozone levels, year-to-year variations in meteorology can make it difficult to assess trends in ozone air quality. Two approaches were considered to adjust ozone trends for meteorological influences: an air quality-meteorology statistical model developed by EPA (i.e., Cox method), and statistical grouping of meteorological variables performed by LADCO (i.e., Classification and Regression Trees, or CART).

Cox Method: This method uses a statistical model to 'remove' the annual effect of meteorology on ozone (Cox and Chu, 1993). A regression model was fit to the 1997-2007 data to relate daily peak 8-hour ozone concentrations to six daily meteorological variables plus seasonal and annual factors (Kenski, 2008a). Meteorological variables included were daily maximum temperature, mid-day average relative humidity, morning and afternoon wind speed and wind direction. The model is then used to predict 4th high ozone values. By holding the meteorological effects constant, the long term trend can be examined independently of meteorology. Presumably, any trend reflects changes in emissions of ozone precursors.

Figure 11a shows the meteorologically-adjusted 4th high ozone concentrations for several monitors near major urban areas in the region. The plots indicate a general downward trend since the late 1990s for most cities, indicating that recent emission reductions have had a positive effect in improving ozone air quality.

A similar model was run to examine meteorologically adjusted trends in seasonal average ozone. This model incorporates more meteorological variables, including rain and long-distance transport (direction and distance). Model development was documented in Camalier et al., 2007. The seasonal average trends are shown in Figure 11b. Trends determined by seasonal model for the same set of sites examined above are consistent with those developed by the 4th high model.

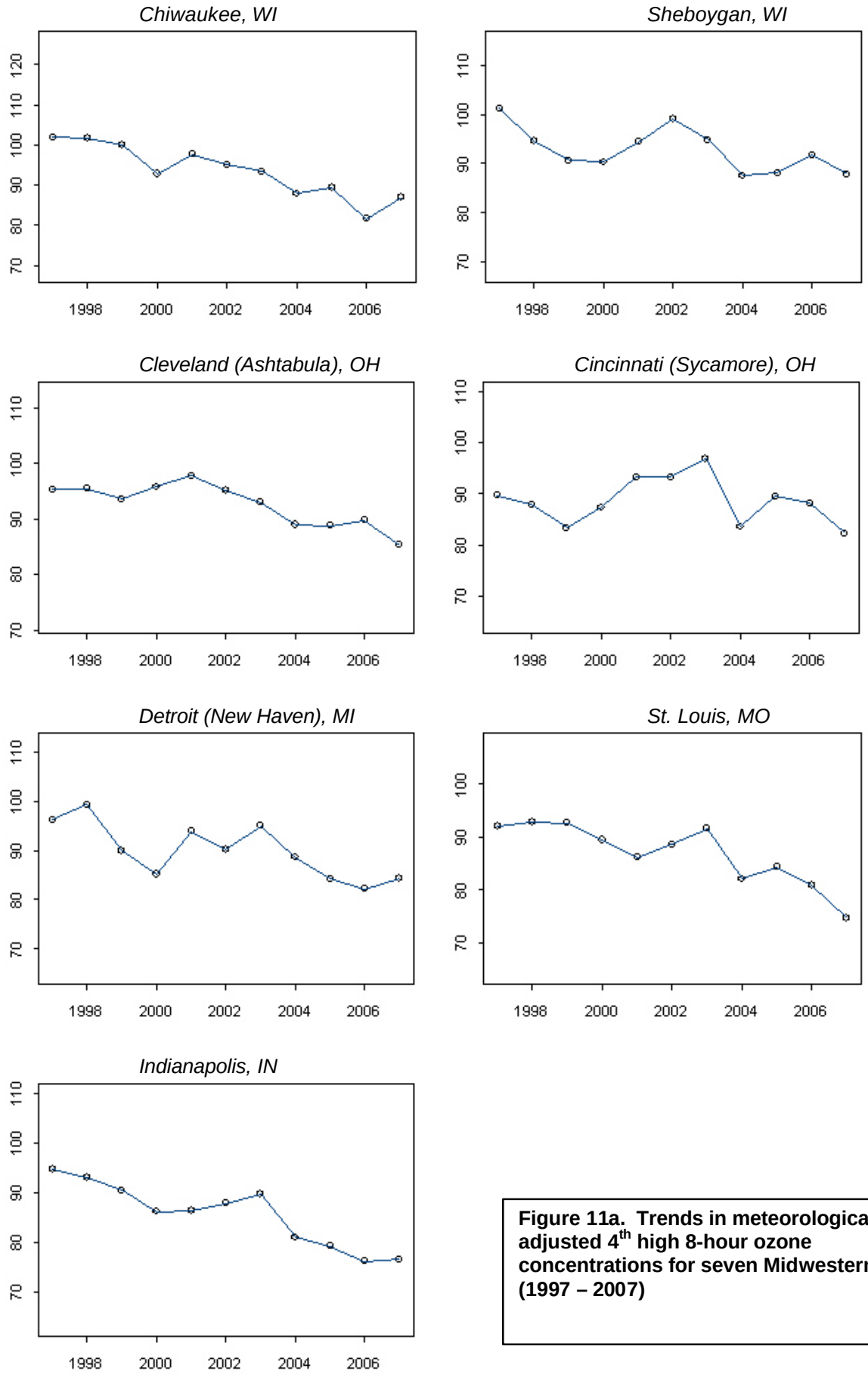


Figure 11a. Trends in meteorologically adjusted 4th high 8-hour ozone concentrations for seven Midwestern sites (1997 – 2007)

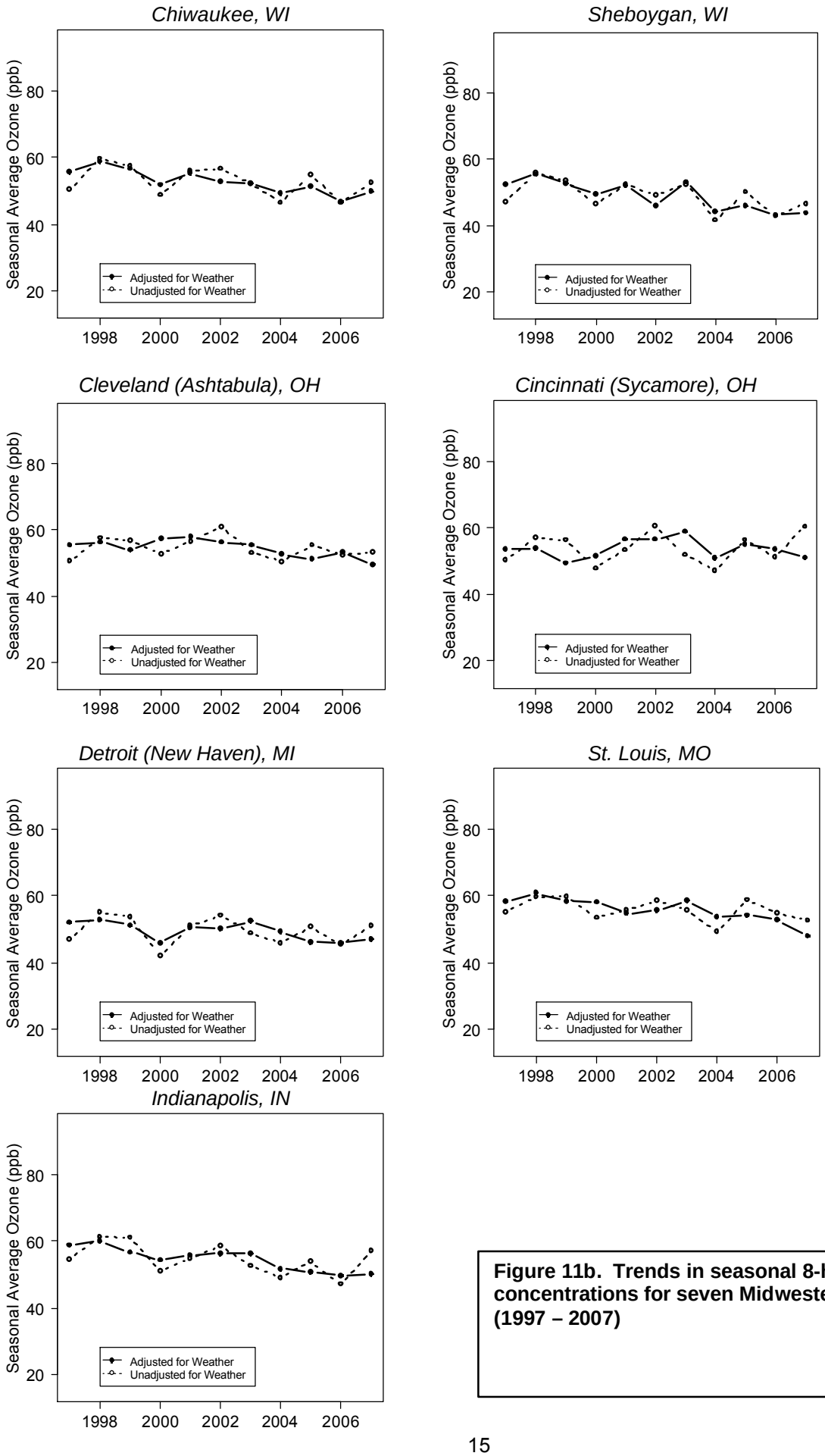


Figure 11b. Trends in seasonal 8-hour ozone concentrations for seven Midwestern sites (1997 – 2007)

CART: Classification and Regression Tree (CART) analysis is another statistical technique which partitions data sets into similar groups (Breiman et al., 1984). CART analysis was performed using data for the period 1995-2007 for 22 selected ozone monitors with current 8-hour design values close to or above the standard (Kenski, 2008b). The CART model searches through 60 meteorological variables to determine which are most efficient in predicting ozone. Although the exact selection of predictive variables changes from site to site, the most common predictors were temperature, wind direction, and relative humidity. Only occasionally were upper air variables, transport time or distance, lake breeze, or other variables significant. (Note, the ozone and meteorological data for the CART analysis are the same as used in the EPA/Cox analysis.)

For each monitor, regression trees were developed that classify each summer day (May-September) by its meteorological conditions. Similar days are assigned to nodes, which are equivalent to branches of the regression tree. Ozone time series for the higher concentration nodes are plotted for select sites in Figure 12. By grouping days with similar meteorology, the influence of meteorological variability on the trend in ozone concentrations is partially removed; the remaining trend is presumed to be due to trends in precursor emissions or other non-meteorological influences. Trends over the 13-year period at most sites were found to be declining, with the exception of Detroit which showed fairly flat trends. Comparison of the average of the high concentration node values for 2001-2003 v. 2005-2007 showed an improvement of about 5 ppb across all sites (even Detroit).

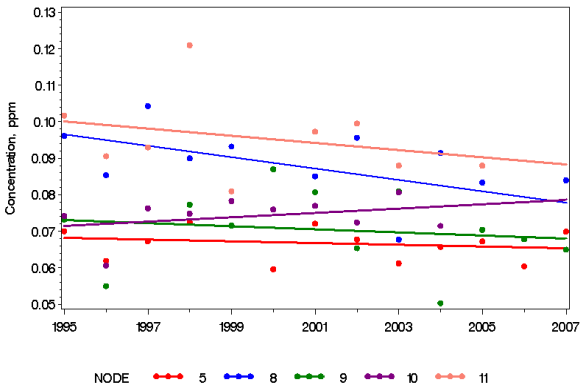
The effect of meteorology was further examined by using an ozone conduciveness index (Kenski, 2008b). This metric reflects the variability from the 13-year average in the number of days in the higher ozone concentration nodes (see Figure 13). Examination of these plots indicates:

- 2002 and 2005 were both above normal, with 2002 tending to be more severe; and
- 2001-2003 and 2005-2007 were both above normal, with no clear pattern in which period was more severe (i.e., ozone conduciveness values were similar at most sites, 2001-2003 values were higher at a few sites, and 2005-2007 values were higher at a few sites).

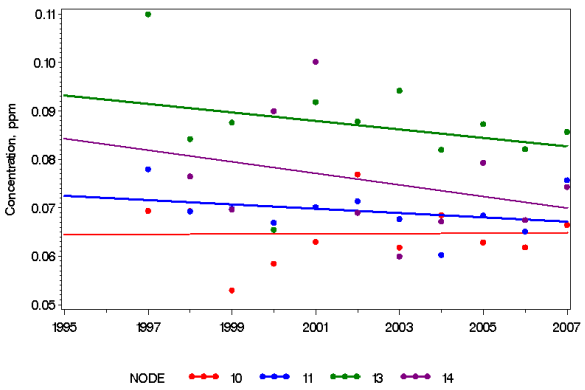
Given the similarity in ozone conduciveness between 2001-2003 and 2005-2007, the improvement in ozone levels noted above is presumed to be due to non-meteorological factors (i.e., emission reductions).

In conclusion, all three statistical approaches (CART and the two nonlinear regression models) show a similar result; ozone in the urban areas of the LADCO region has declined during the 1997-2007 period, even when meteorological variability is accounted for. The decreases are present whether seasonal average ozone, peak values (annual 4th highs), or a subset of high days with similar meteorology are considered. The consistency in results across models is a good indication that these trends reflect impacts of emission control programs.

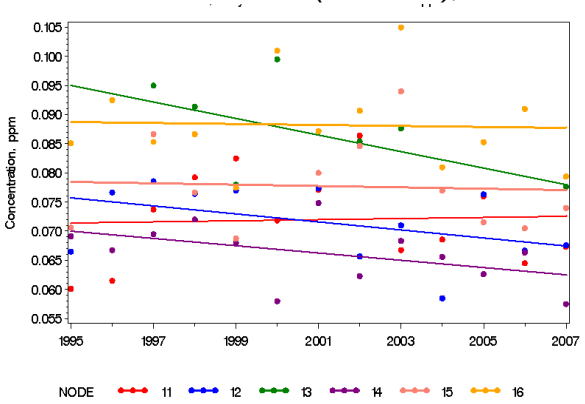
Chiwaukee, WI



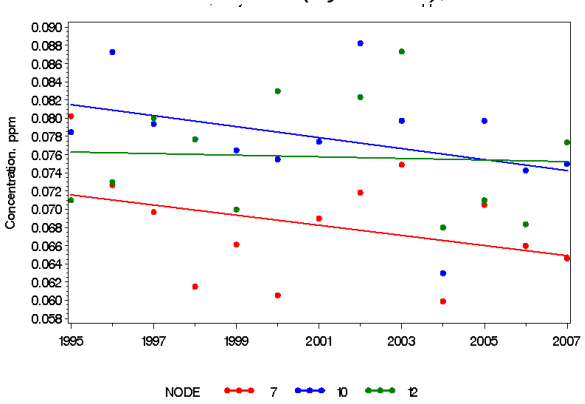
Sheboygan, WI



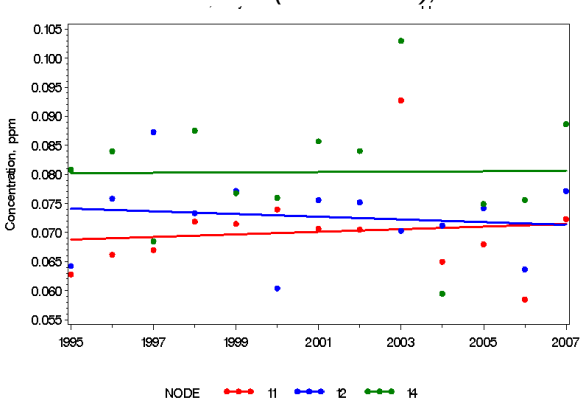
Cleveland (Ashtabula), OH



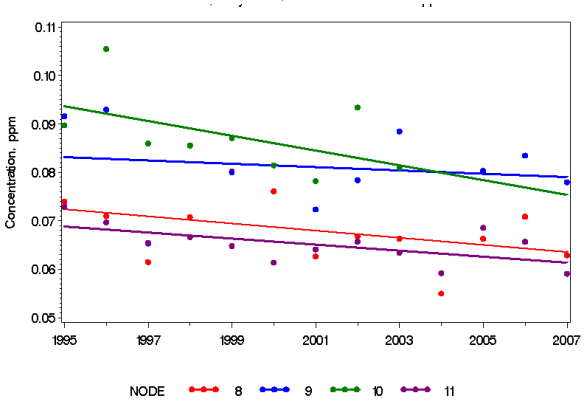
Cincinnati (Sycamore), OH



Detroit (New Haven), MI



St. Louis, MO



Indianapolis, IN

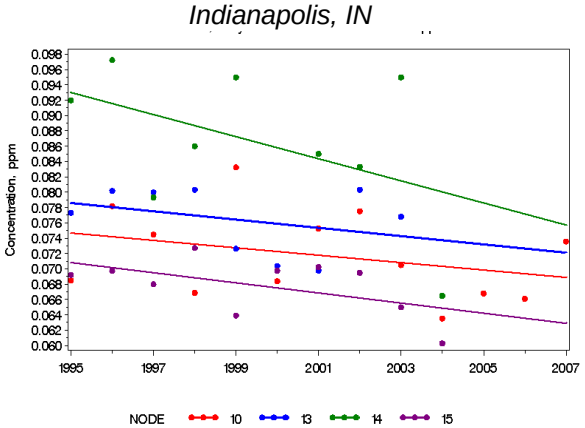


Figure 12. Trends for higher ozone CART groups (average ozone > 65 ppb) for seven Midwestern sites (1995 – 2007)

Note: line represents linear best fit

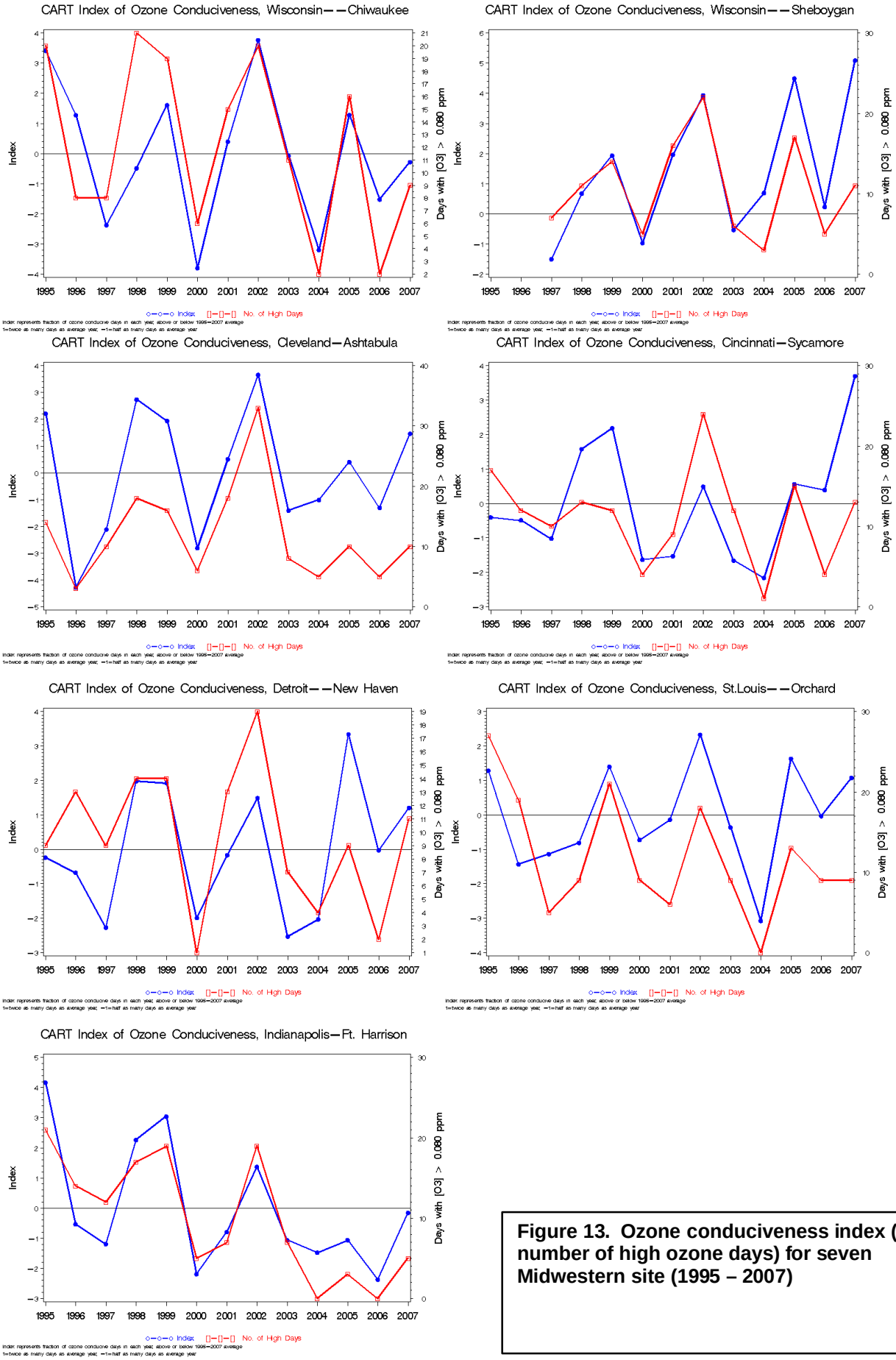


Figure 13. Ozone conduciveness index (and number of high ozone days) for seven Midwestern site (1995 – 2007)

Precursor Sensitivity: Ozone is formed from the reactions of hydrocarbons and nitrogen oxides under meteorological conditions that are conducive to such reactions (i.e., warm temperatures and strong sunlight). In areas with high VOC/NOx ratios, typical of rural environments (with low NOx), ozone tends to be more responsive to reductions in NOx. Conversely, in areas with low VOC/NOx ratios, typical of urban environments (with high NOx), ozone tends to be more responsive to VOC reductions.

An analysis of VOC and NO_x-limitation was conducted with the ozone MAPPER program, which is based on the Smog Production (SP) algorithm (Blanchard, et al., 2003). The "Extent of Reaction" parameter in the SP algorithm provides an indication of VOC and NOx sensitivity:

Extent Range	**Precursor Sensitivity**
< 0.6	VOC-sensitive
0.6 – 0.8	Transitional
> 0.8	NOx-sensitive

A map of the Extent of Reaction values for high ozone days is provided in Figure 14. As can be seen, ozone is usually VOC-limited in cities and NOx-limited in rural areas. (Data from aircraft measurements suggest that ozone is usually NO_x-limited over Lake Michigan and away from urban centers on days when ozone in the urban centers is VOC-limited.) The highest ozone days were found to be NO_x-limited. This analysis suggests that a NOx reduction strategy would be effective in reducing ozone levels. Examination of day-of-week concentrations, however, raises some question about the effectiveness of NOx reductions.

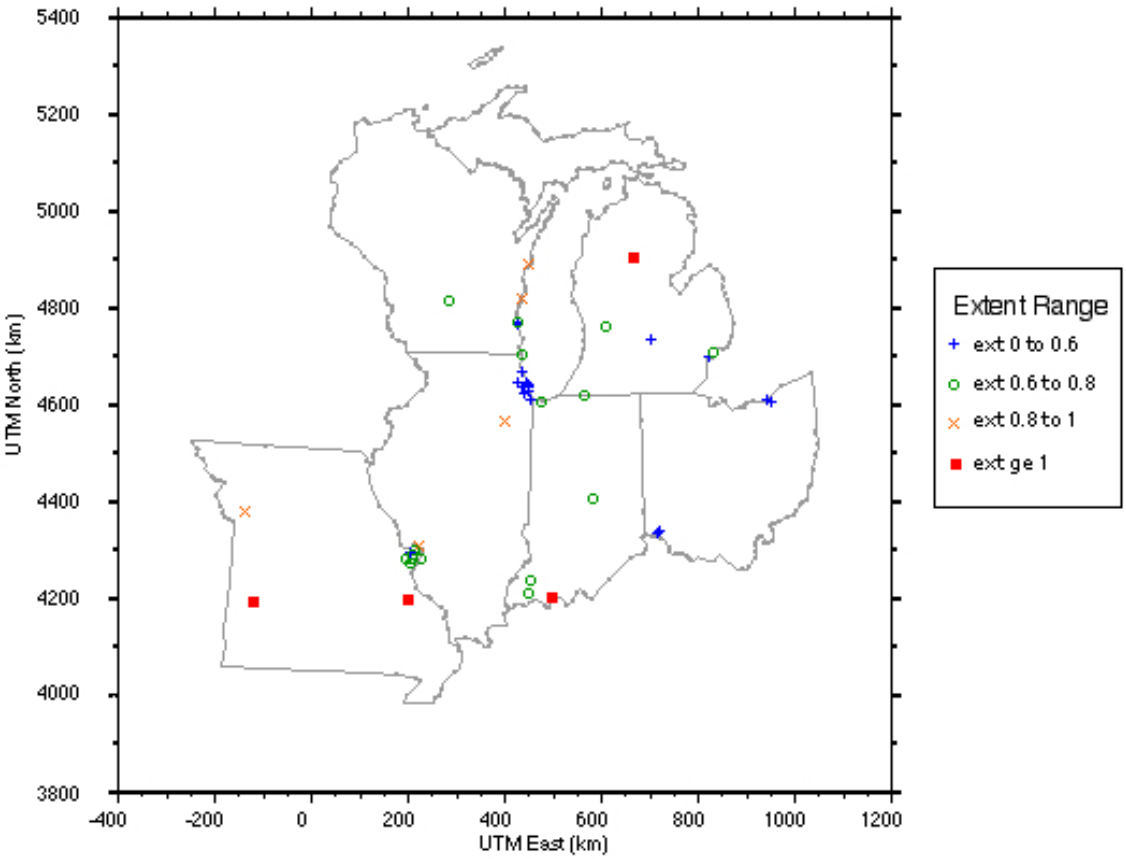


Figure 14. Mean afternoon extent of reaction (1998 – 2002)

Blanchard (2004 and 2005a) examined weekend-weekday differences in ozone and NO_x in the Midwest. All urban areas in these two studies exhibited substantially lower (40-60%) weekend concentrations of NO_x compared to weekday concentrations. Despite lower weekend NO_x concentrations, weekend ozone concentrations were not lower; in fact, most urban sites had higher concentrations of ozone, although the increase was generally not statistically significant (see Figure 15). This small but counterproductive change in **local** ozone concentrations suggests that **local** urban-scale NO_x reductions alone may not be very effective.

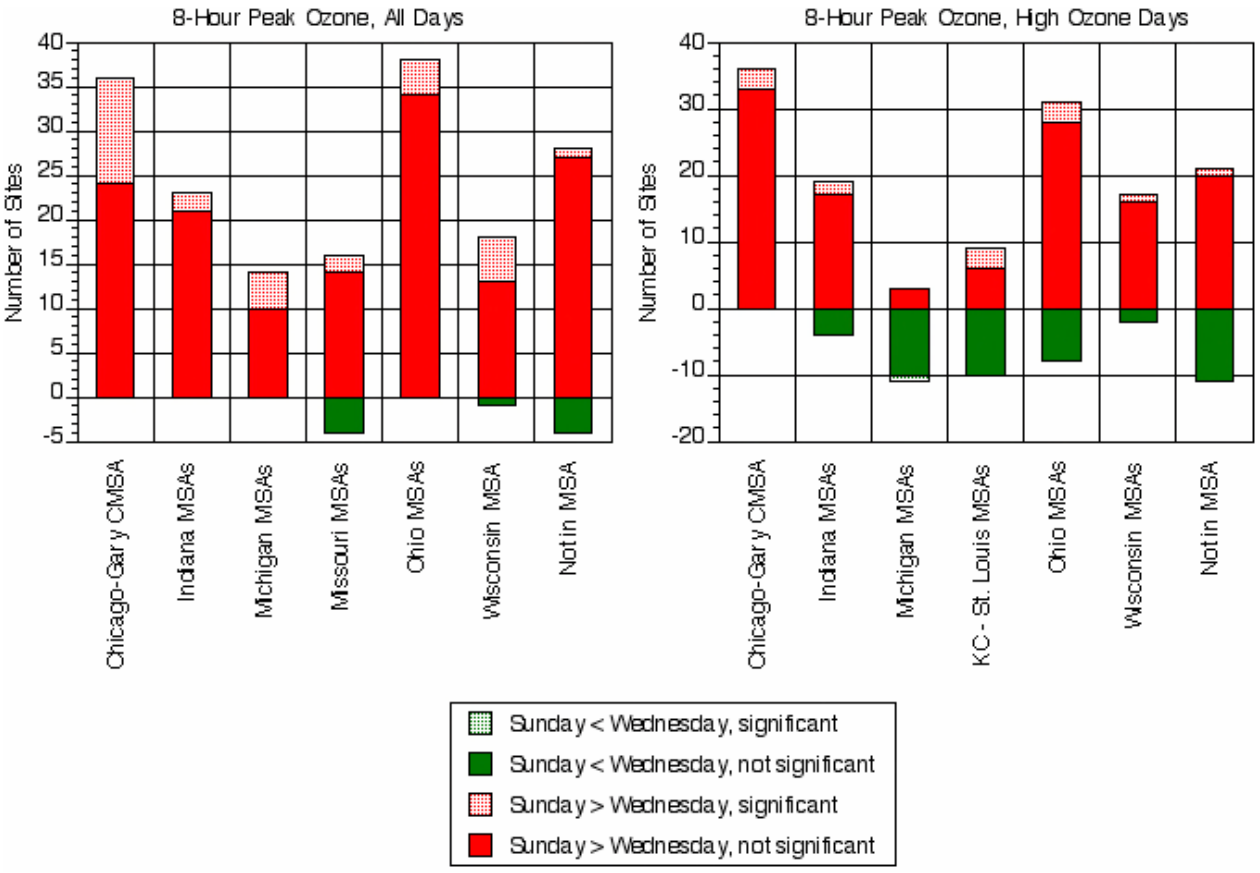


Figure 15. Weekday/weekend differences in 8-hour ozone – number of sites with weekend increase (positive values) v. number of sites with weekend decreases (negative values)

Two additional analyses, however, demonstrate the positive effect of NOx emission reductions on downwind ozone concentrations. First, Blanchard (2005a) looked at the effect of changes in precursor emissions in Chicago on downwind ozone levels in western Michigan. For the transport days of interest (i.e., southwesterly flow during the summers of 1999 – 2002), mean NOx concentrations in Chicago are about 50% lower and mean ozone concentrations at the (downwind) western Michigan sites are about 1.5 – 5.2 ppb (3 – 8 %) lower on Sunday compared to Wednesday. This degree of change in downwind ozone levels suggests a positive, albeit non-linear response to urban area emission reductions.

Second, Environ (2007a) examined the effect of differences in day-of-week emissions in southeastern Michigan on downwind ozone levels. This modeling study found that weekend changes in ozone precursor emissions cause both increases and decreases in Southeast Michigan ozone, depending upon location and time:

- Weekend increases in 8-hour maximum ozone occur in and immediately downwind of the Detroit urban area (i.e., in VOC-sensitive areas).
- Weekend decreases in 8-hour maximum ozone occur outside and downwind of the Detroit urban area (i.e., in NOx-sensitive areas).
- At the location of the peak 8-hour ozone downwind of Detroit, ozone was lower on weekends than weekdays.
- Ozone benefits (reductions) due to weekend emission changes in Southeast Michigan can be transported downwind for hundreds of miles.
- Southeast Michigan benefits from lower ozone transported into the region on Saturday through Monday because of weekend emission changes in upwind areas.

In summary, these analyses suggest that urban VOC reductions and regional (urban and rural) NOx reductions will be effective in lowering ozone concentrations. Local NOx reductions can lead to local ozone increases (i.e., NOx disbenefits), but this effect does not appear to pose a problem with respect to attainment of the standard. It should also be noted that urban VOC and regional NOx reductions are likely to have multi-pollutant benefits (e.g., both lower ozone and $PM_{2.5}$ impacts).

2.2 $PM_{2.5}$

In 1997, EPA adopted the $PM_{2.5}$ standards of 15 ug/m^3 (annual average) and 65 ug/m3 (24-hour average). The annual standard is attained if the 3-year average of the annual average $PM_{2.5}$ concentration is less than or equal to the level of the standard. The daily standard is attained if the 98th percentile of 24-hour $PM_{2.5}$ concentrations in a year, averaged over three years, is less than or equal to the level of the standard.

In 2006, EPA revised the $PM_{2.5}$ standards to 15 ug/m^3 (annual average) and 35 ug/m^3 (24-hour average).

Current Conditions: Maps of annual and 24-hour $PM_{2.5}$ design values for the 3-year period 2005-2007 are shown in Figure 16. The "hotter" colors represent higher concentrations, where red dots represent sites with design values above the annual standard. Currently, there are 30 sites in violation of the annual $PM_{2.5}$ standard.

Table 2 provides the annual $PM_{2.5}$ concentrations and associated design values since 2003 for several high monitoring sites throughout the region.

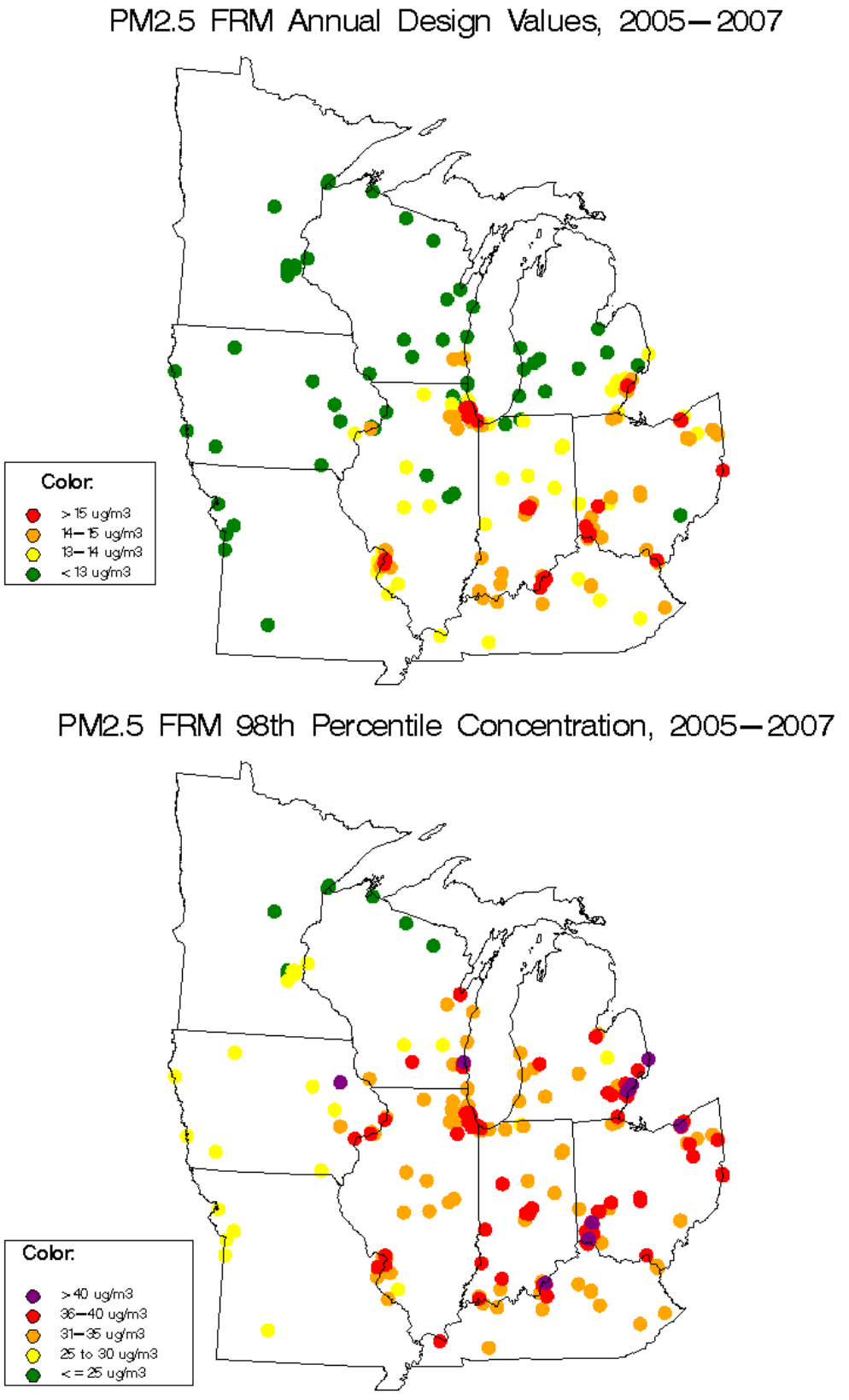


Figure 16. $PM_{2.5}$ design values - annual average (top) and 24-hour average (bottom) (2005-2007)

Table 2. PM2.5 Data for Select Sites in 5-State Region

			Annual Average Conc.					Design Values			2005 BY	2002 BY
Key Site	**County**	**Site ID**	**'03**	**'04**	**'05**	**'06**	**'07**	**'03 - '05**	**'04 - '06**	**'05 - '07**	**Average w/ 2007**	**Average**
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	**15.0**	**15.6**
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**	
Indy - Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**
Indy - W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**	
Indy - Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.0	15.3	17.0	16.2	16.2	**16.5**	**16.7**
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.4	13.6	14.7	15.4	14.9	14.9	**15.1**	**16.0**
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	15.9	**16.2**	**16.3**
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.4	**15.2**	**15.7**
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**

When EPA initially set the 24-hour standard at 65 µg/m^3, it also adopted the following concentration ranges for its Air Quality Index (AQI) scale:

Good	< 15 ug/m^3
Moderate	15-40 µg/m^3
Unhealthy for Sensitive Groups (USG)	40-65 µg/m^3
Unhealthy	65-150 µg/m^3

Figure 17 shows the frequency of these AQI categories for major metropolitan areas in the region. Daily average concentrations are often in the moderate range and occasionally in the USG range. Moderate and USG levels can occur any time of the year.

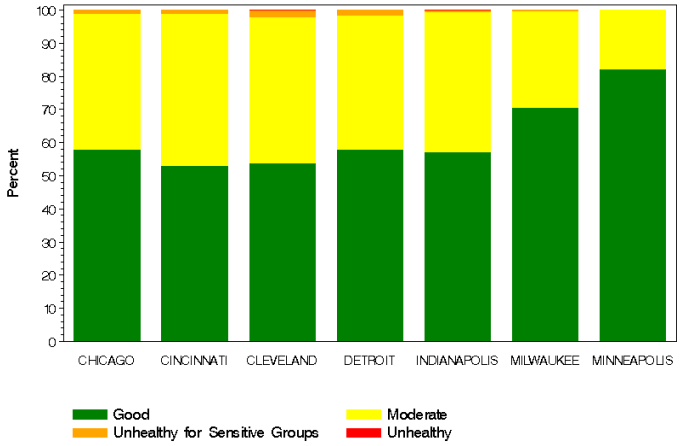


Figure 17. Percent of days in AQI categories for $PM_{2.5}$ (2002-2004)

Data Variability: $PM_{2.5}$ concentrations vary spatially, temporally, and chemically in the region. This variability is discussed further below.

On an annual basis, $PM_{2.5}$ exhibits a distinct and consistent spatial pattern. As seen in Figure 16, across the Midwest, annual concentrations follow a gradient from low values (5-6 µg/m^3) in northern and western areas (Minnesota and northern Wisconsin) to high values (17-18 µg/m^3) in Ohio and along the Ohio River. In addition, concentrations in urban areas are higher than in upwind rural areas, indicating that local urban sources add a significant increment of 2-3 µg/m^3 to the regional background of 12 - 14 µg/m^3 (see Figure 18).

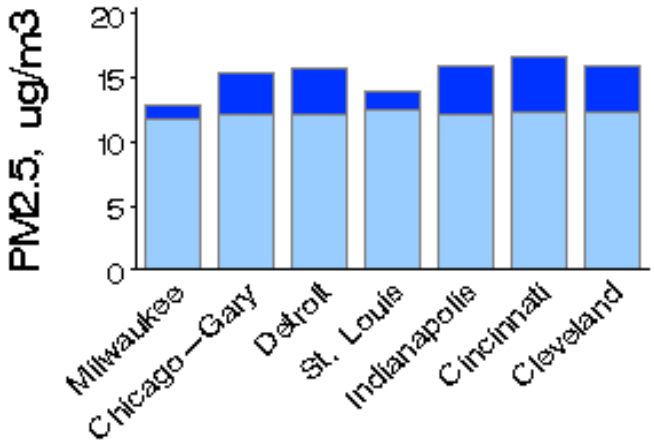


Figure 18. Regional (lighter shading) v. local components (darker shading) of annual average $PM_{2.5}$ concentrations

Because monitoring for $PM_{2.5}$ only began in earnest in 1999, after promulgation of the $PM_{2.5}$ standard, limited data are available to assess trends. Time series based on federal reference method (FRM) $PM_{2.5}$-mass data show a downward trend in each state (see Figure 19)[7].

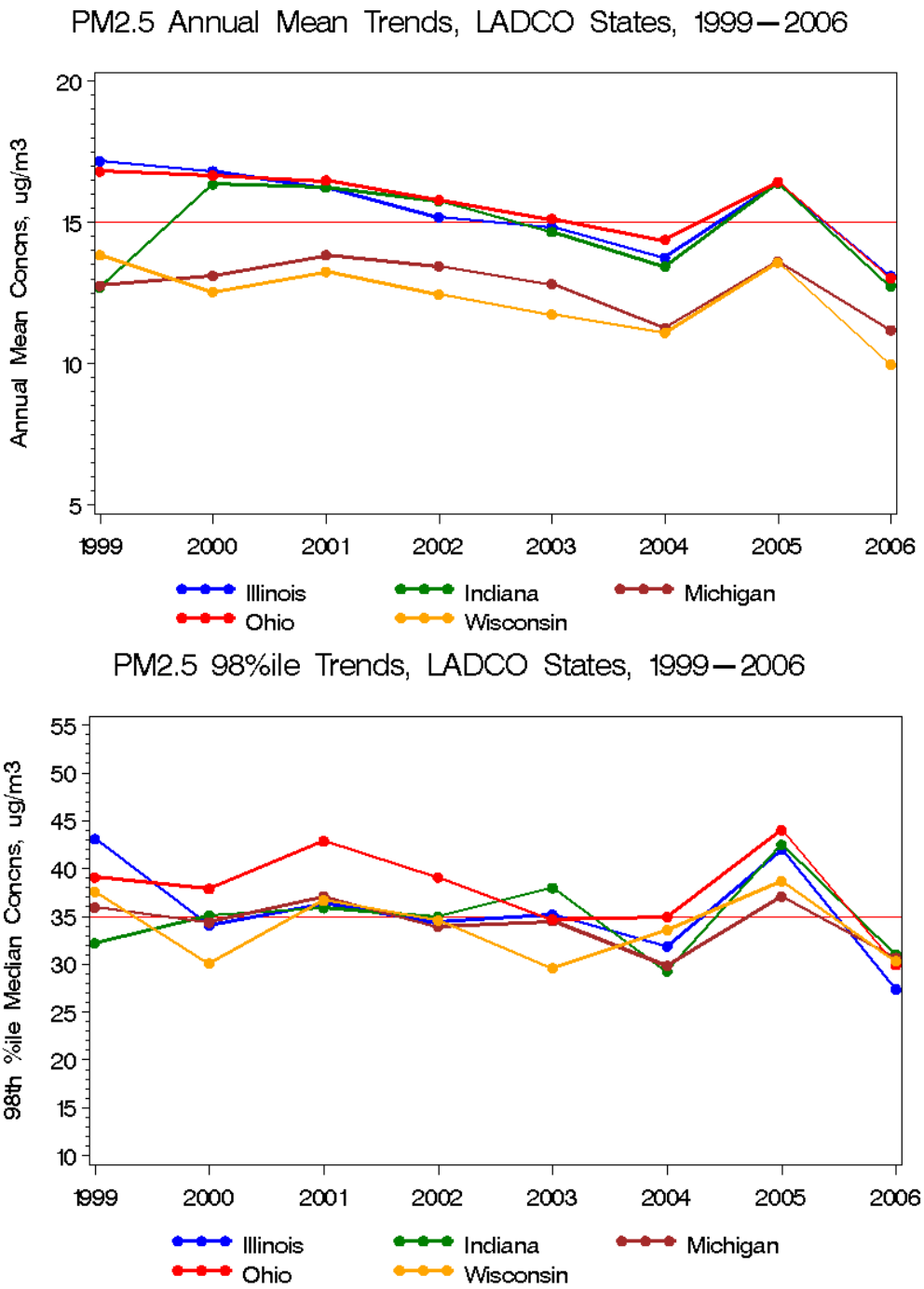


Figure 19. $PM_{2.5}$ trends in annual average (top) and daily concentrations (bottom)

[7] Despite the general downward trend since 1999, all states experienced an increase during 2005. Further analyses are underway to understand this increase (e.g., examination of meteorological and emissions effects).

A statistical analysis of $PM_{2.5}$ trends was performed using the nonparametric Theil test for slope (Hollander and Wolfe, 1973). Trends were generally consistent around the region, for both PM mass and for the individual components of mass. Figure 20 shows trends for $PM_{2.5}$ based on FRM data at sites with six or more years of data since 1999. The size and direction of each arrow shows the size and direction of the trend for each site; solid arrows show statistically significant trends and open arrows show trends that are not significant. Region-wide decreases are widespread and consistent; all sites had decreasing concentration trends (13 of the 38 were statistically significant). The average decrease for this set of sites is -0.24 ug/m^3/year.

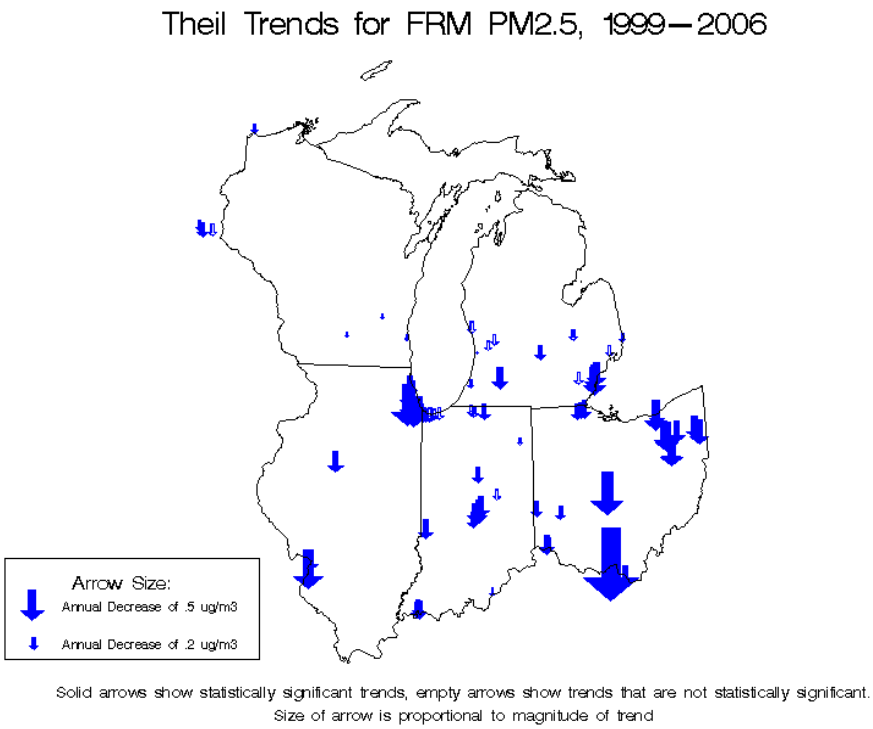


Figure 20. Annual trends in $PM_{2.5}$ mass (1999 – 2006)

Seasonal trends show mostly similar patterns (Figure 21). Trends were downward at most sites and seasons, with overall seasonal averages varying between -0.15 to -0.56 ug/m^3/year. The strongest and most significant decreases took place during the winter quarter (January - March). No statistically significant increasing trends were observed.

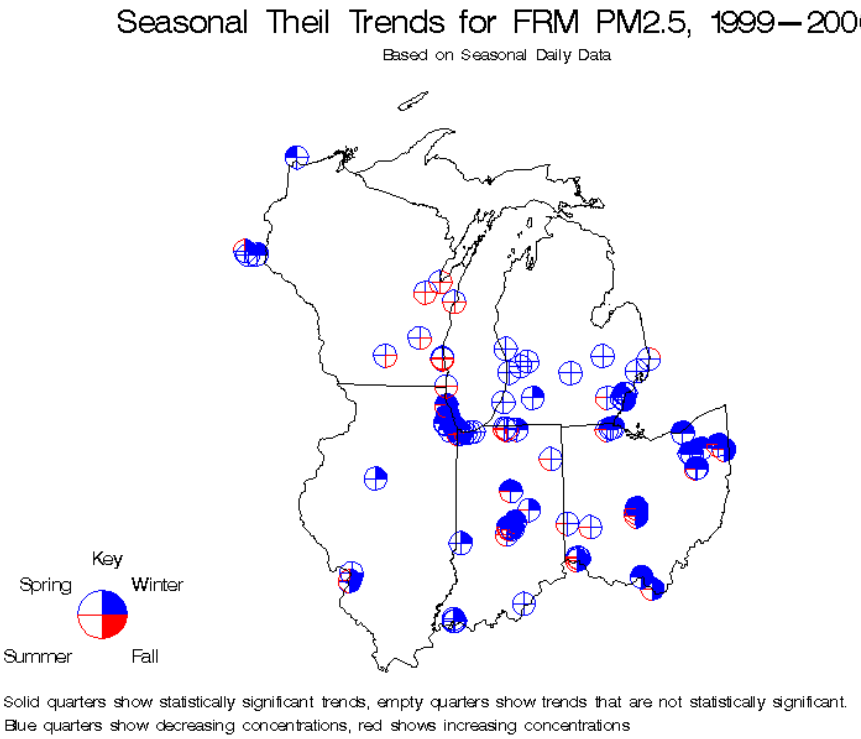


Figure 21. Seasonal trends in $PM_{2.5}$ mass (1999 – 2006)

$PM_{2.5}$ shows a slight variation from weekday to weekend, as seen in Figure 22. Although most cities have slightly lower concentrations on the weekend, the difference is usually less than 1 $\mu g/m^3$. There is a more pronounced weekday/weekend difference at monitoring sites that are strongly source-influenced. Rural monitors tend to show less of a weekday/weekend pattern than urban monitors.

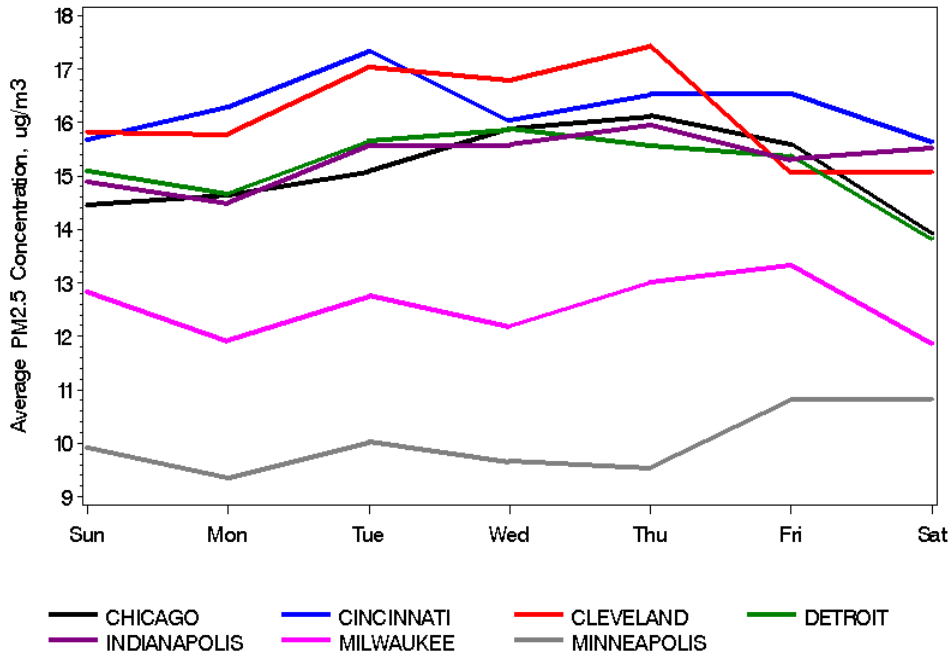


Figure 22 Day-of-week variability in $PM_{2.5}$ (2002-2004)

In the Midwest, $PM_{2.5}$ is made up of mostly ammonium sulfate, ammonium nitrate, and organic carbon in approximately equal proportions on an annual average basis. Elemental carbon and crustal matter (also referred to as soil) contribute less than 5% each.

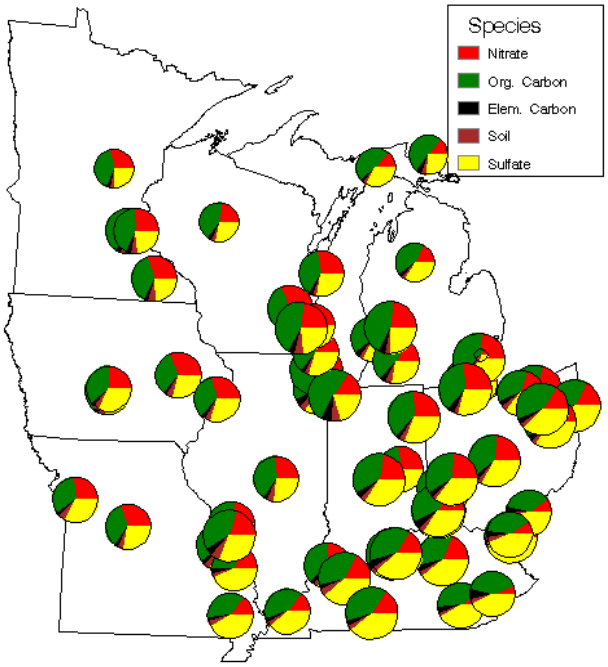


Figure 23. Spatial map of $PM_{2.5}$ chemical composition in the Midwest (2002-2003)

The three major components vary spatially (Figure 23), including notable urban and rural differences (Figure 24). The components also vary seasonally (Figure 25). These patterns account for much of the annual variability in $PM_{2.5}$ mass noted above.

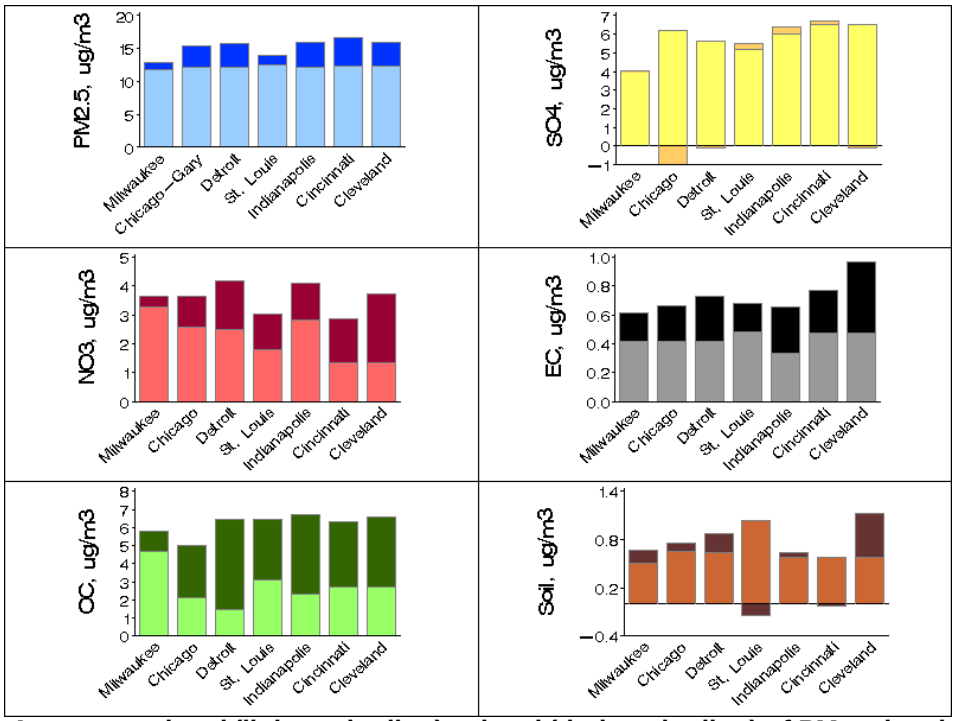


Figure 24. Average regional (lighter shading) v. local (darker shading) of $PM_{2.5}$ chemical species

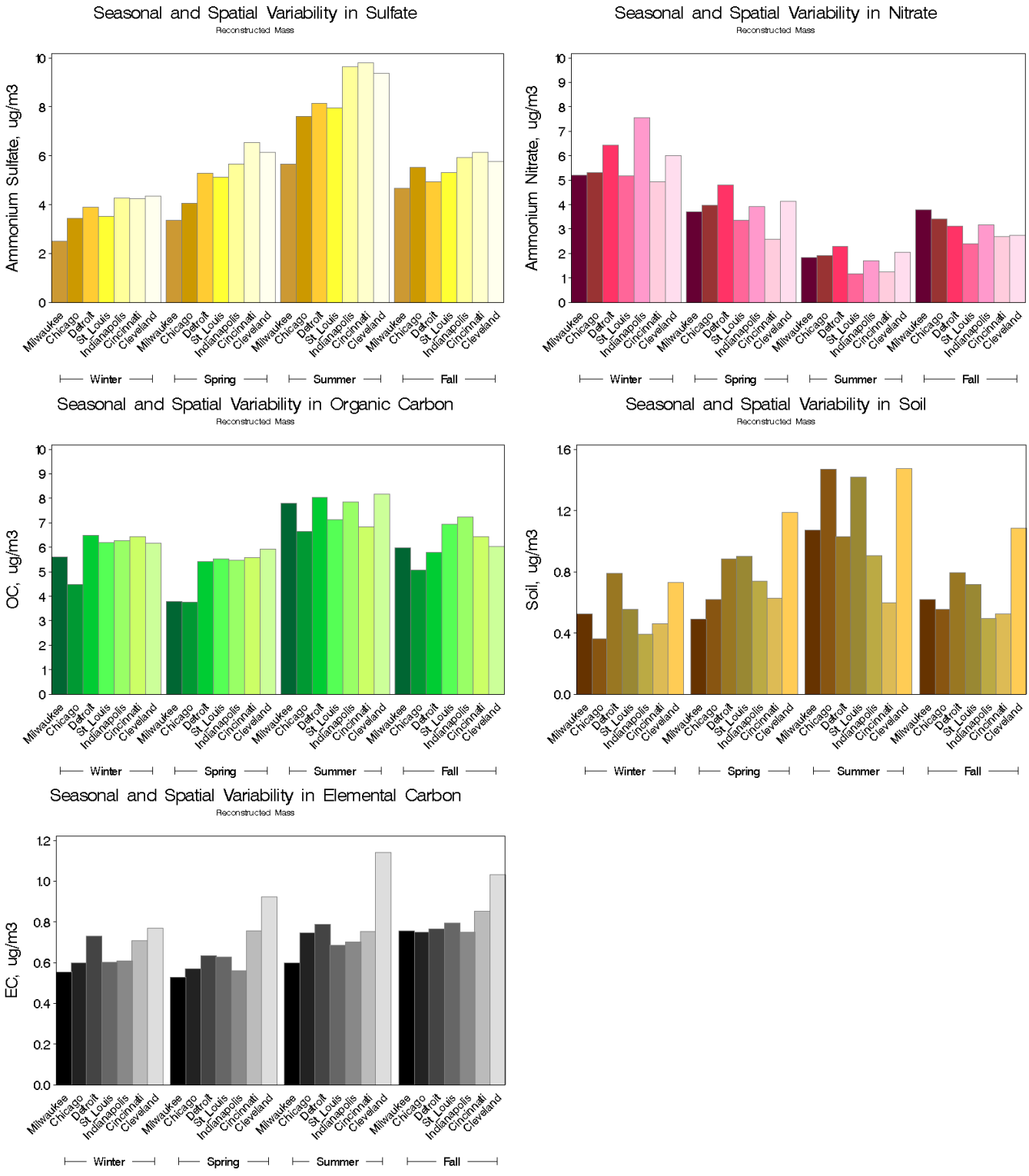


Figure 25 Seasonal and spatial variability in $PM_{2.5}$ components

Ammonium sulfate peaks in the summer and is highest in the southern and eastern parts of the Midwest, closest to the Ohio River Valley. Sulfate is primarily a regional pollutant; concentrations are similar in rural and urban areas and highly correlated over large distances. It is formed when sulfuric acid (an oxidation product of sulfur dioxide) and ammonia react in the atmosphere, especially in cloud droplets. Coal combustion is the primary source of sulfur dioxide; ammonia is emitted primarily from animal husbandry operations and fertilizer use.

Ammonium nitrate has almost the opposite spatial and seasonal pattern, with the highest concentrations occurring in the winter and in the northern parts of the region. Nitrate seems to have both regional and local sources, because urban concentrations are higher than rural upwind concentrations. Ammonium nitrate forms when nitric acid reacts with ammonia, a process that is enhanced when temperatures are low and humidity is high. Nitric acid is a product of the oxidation of nitric oxide, a pollutant that is emitted by combustion processes.

Organic carbon is more consistent from season to season and city to city, although concentrations are generally slightly higher in the summer. Like nitrate, organic carbon has both regional and local components. Particulate organic carbon can be emitted directly from cars and other fuel combustion sources or formed in a secondary process as volatile organic gases react and condense. In rural areas, summer organic carbon has significant contributions from biogenic sources.

Precursor Sensitivity: Data from the Midwest ammonia monitoring network were analyzed with thermodynamic equilibrium models to assess the effect of changes in precursor gas concentrations on $PM_{2.5}$ concentrations (Blanchard, 2005b). These analyses indicate that particle formation responds in varying degrees to reductions in sulfate, nitric acid, and ammonia. Based on Figure 26, which shows $PM_{2.5}$ concentrations as a function of sulfate, nitric acid (HNO3), and ammonia (NH3), several key findings should be noted:

- $PM_{2.5}$ mass is sensitive to reductions in sulfate at all times of the year and all parts of the region. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases.

- $PM_{2.5}$ mass is also sensitive to reductions in nitric acid and ammonia. The greatest $PM_{2.5}$ decrease in response to nitric acid reductions occurs during the winter, when nitrate is a significant fraction of $PM_{2.5}$.

- Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

- Ammonia becomes more limiting as one moves from west to east across the region.

Examination of weekend/weekday difference in PM-nitrate and NOx concentrations in the Midwest demonstrate that reductions in local (urban) NOx lead to reductions, albeit non-proportional reductions, in PM-nitrate (Blanchard, 2004). This result is consistent with analyses of continuous PM-nitrate from several US cities, including St. Louis (Millstein, et al, 2007).

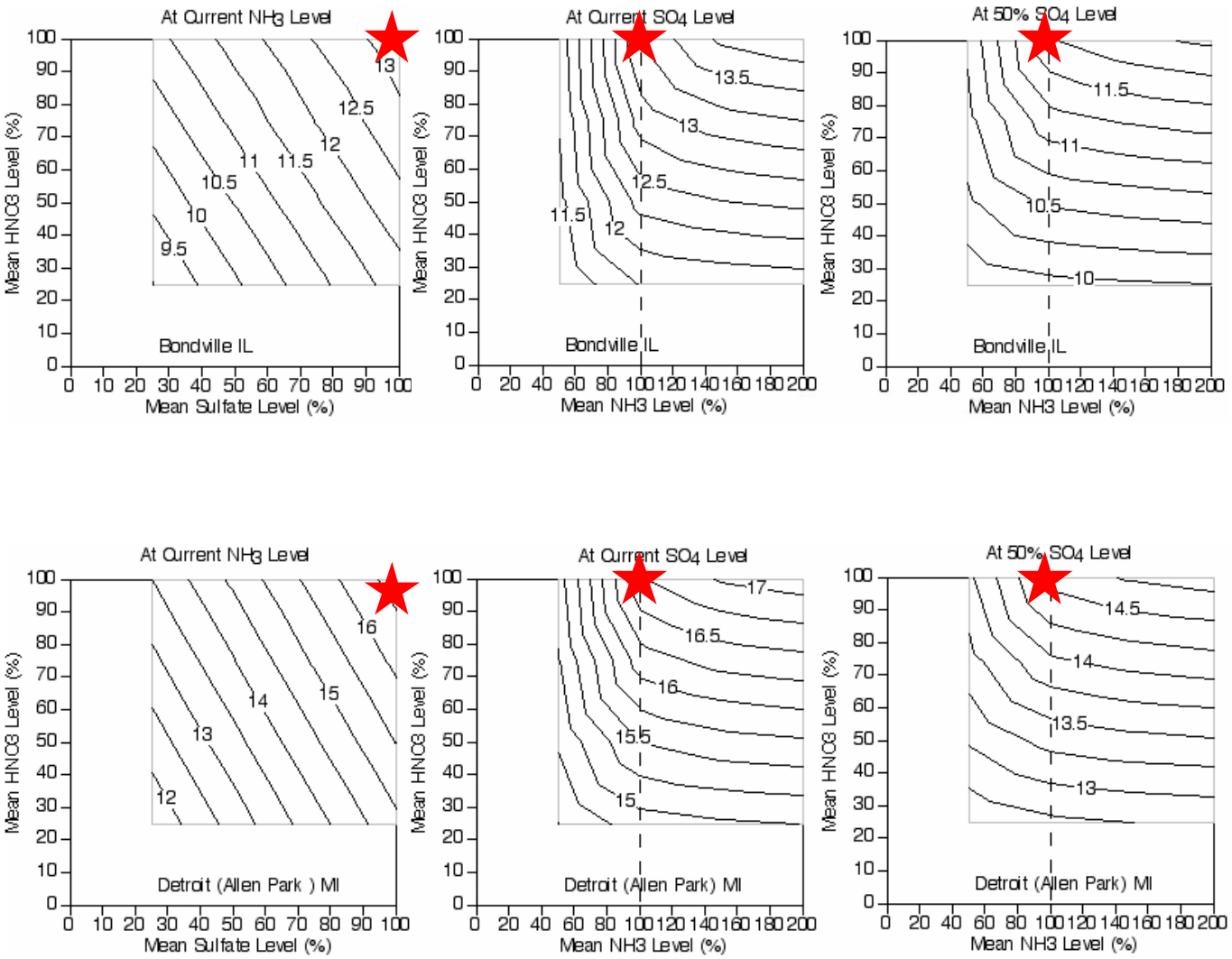


Figure 26. Predicted mean PM fine mass concentrations at Bondville, IL (top) and Detroit (Allen Park), MI (bottom) as functions of changes in sulfate, nitric acid (HNO3), and ammonia (NH3)

Note: starting at the baseline values (represented by the red star), either moving downward (reductions in nitric acid) or moving leftward (reductions in sulfate or ammonia) results in lower $PM_{2.5}$ values

Meteorology: $PM_{2.5}$ concentrations are not as strongly influenced by meteorology as ozone, but the two pollutants share some similar meteorological dependencies. In the summer, conditions that are conducive to ozone (hot temperatures, stagnant air masses, and low wind speeds due to stationary high pressure systems) also frequently give rise to high $PM_{2.5}$. In the case of PM, the reason is two-fold: (1) stagnation and limited mixing under these conditions cause $PM_{2.5}$ to build up, usually over several days, and (2) these conditions generally promote higher conversion of important precursors (SO_2 to SO_4) and higher emissions of some precursors, especially biogenic carbon. Wind direction is another strong determinant of $PM_{2.5}$; air transported from polluted source regions has higher concentrations.

Unlike ozone, $PM_{2.5}$ has occasional winter episodes. Conditions are similar to those for summer episodes, in that stationary high pressure and (seasonally) warm temperatures are usually factors. Winter episodes are also fueled by high humidity and low mixing heights.

$PM_{2.5}$ chemical species show noticeable transport influences. Trajectory analyses have demonstrated that high PM-sulfate is associated with air masses that traveled through the sulfate-rich Ohio River Valley (Poirot, et al, 2002 and Kenski, 2004). Likewise, high PM-nitrate is associated with air masses that traveled through the ammonia-rich Midwest. Figure 27 shows results from an ensemble trajectory analysis of 17 rural eastern IMPROVE sites.

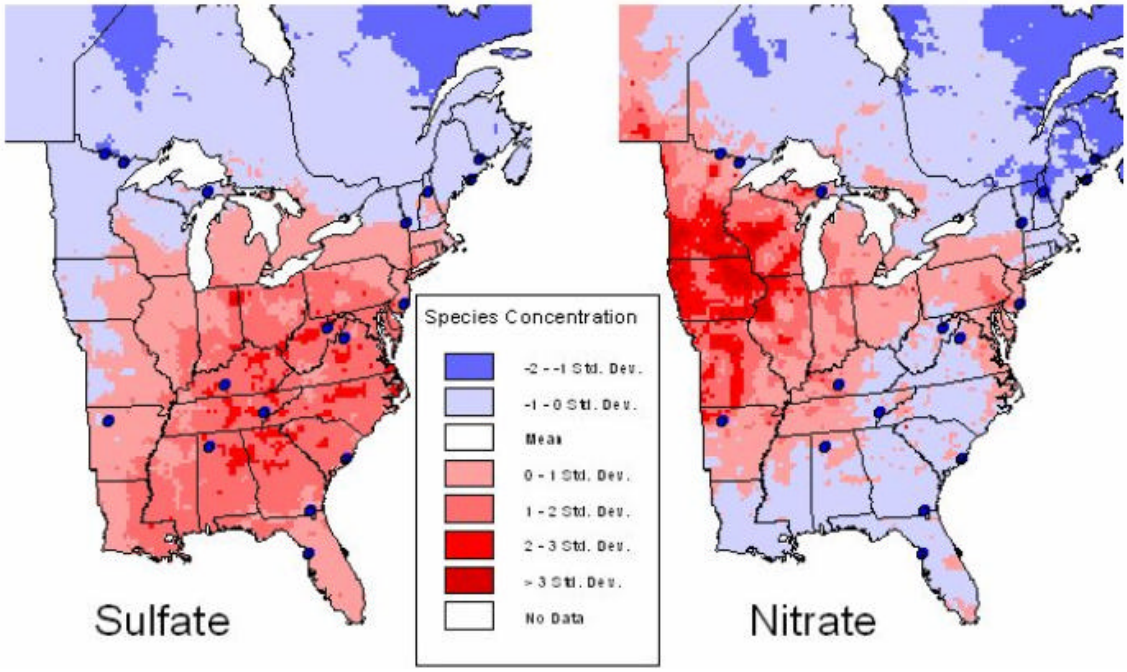


Figure 27. Sulfate and nitrate source regions based on ensemble trajectory analysis

When these results are considered together with analyses of precursor sensitivity (e.g., Figure 26), one possible conclusion is that ammonia control in the Midwest could be effective at reducing nitrate concentrations. The thermodynamic equilibrium modeling shows that ammonia reductions would reduce PM concentrations in the Midwest, but that nitric acid reductions are more effective when the probable reductions in future sulfate levels are considered.

Source Culpability: Three source apportionment studies were performed using speciated $PM_{2.5}$ monitoring data and statistical analysis methods (Hopke, 2005, STI, 2006, and STI, 2008). Figure 28 summarizes the source contributions from these studies. The studies show that a large portion of $PM_{2.5}$ mass consists of secondary, regional impacts, which cannot be attributed to individual facilities or sources (e.g., secondary sulfate, secondary nitrate, and secondary organic aerosols). Nevertheless, wind analyses (e.g., Figure 27) provide information on likely source regions. Regional- or national-scale control programs may be the most effective way to deal with these impacts. EPA's CAIR, for example, will provide for substantial reductions in SO2 emissions over the eastern half of the U.S., which will reduce sulfate (and $PM_{2.5}$) concentrations and improve visibility levels.

The studies also show that a smaller, yet significant portion of $PM_{2.5}$ mass is due to emissions from nearby (local) sources. Local (urban) excesses occur in many urban areas for organic and elemental carbon, crustal matter, and, in some cases, sulfate. The statistical analysis methods help to identify local sources and quantify their impact. This information is valuable to states wishing to develop control programs to address local impacts. A combination of national/regional-scale and local-scale emission reductions may be necessary to provide for attainment.

The carbon sources are not easily identified in complex urban environments. LADCO's Urban Organics Study (STI, 2006) identified four major sources of organic carbon: mobile sources, burning, industrial sources, and secondary organic aerosols. Additional sampling and analysis is underway in Cleveland and Detroit to provide further information on sources of organic carbon.

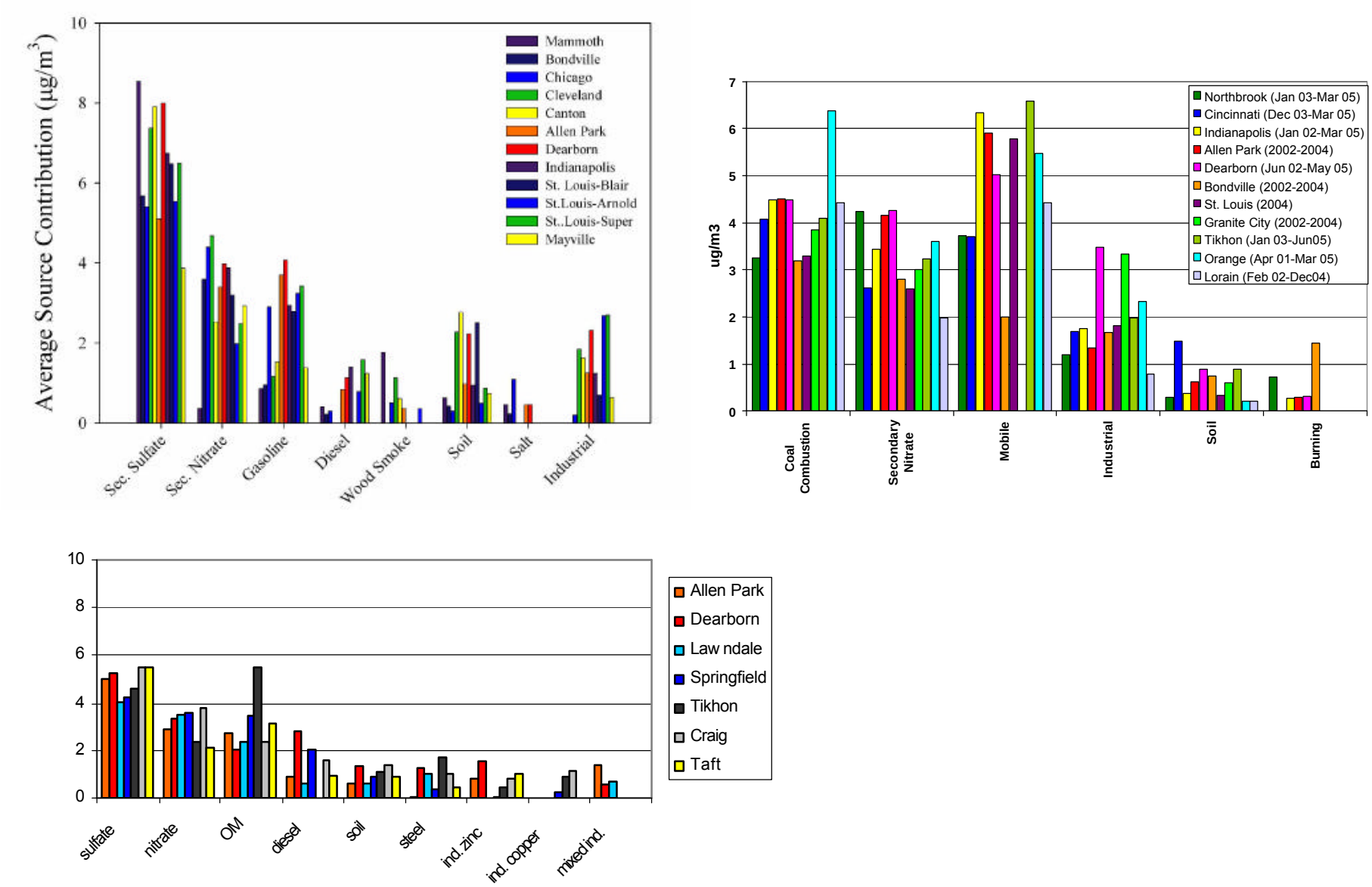


Figure 28. Major Source Contributions in the Midwest based on Hopke, 2005 (upper left), STI, 2006 (upper right), and STI, 2008 (lower left) (Note: the labeling of similar source types varies between studies – e.g., organic carbon/mobile sources are named gasoline and diesel by Hopke, mobile by STI 2006, and OM and diesel by STI 2008)

2.3 Haze

Section 169A of the Clean Air Act sets as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution". To implement this provision, in 1999, EPA adopted regulations to address regional haze visibility impairment (USEPA, 1999). EPA's rule requires states to "make reasonable progress toward meeting the national goal". Specifically, states must establish reasonable progress goals, which provide for improved visibility on the most impaired (20% worst) days sufficient to achieve natural conditions by the year 2064, and for no degradation on the least impaired (20% best) days.

The primary cause of impaired visibility in the Class I areas is pollution by fine particles that scatter light. The degree of impairment, which is expressed in terms of visual range, light extinction (1/Mm), or deciviews (dv), depends not just on the total $PM_{2.5}$ mass concentration, but also on the chemical composition of the particles and meteorological conditions.

Current Conditions: A map of the average light extinction values for the most impaired (20% worst) visibility days for the 5-year baseline period (2000-2004) is shown in Figure 29.

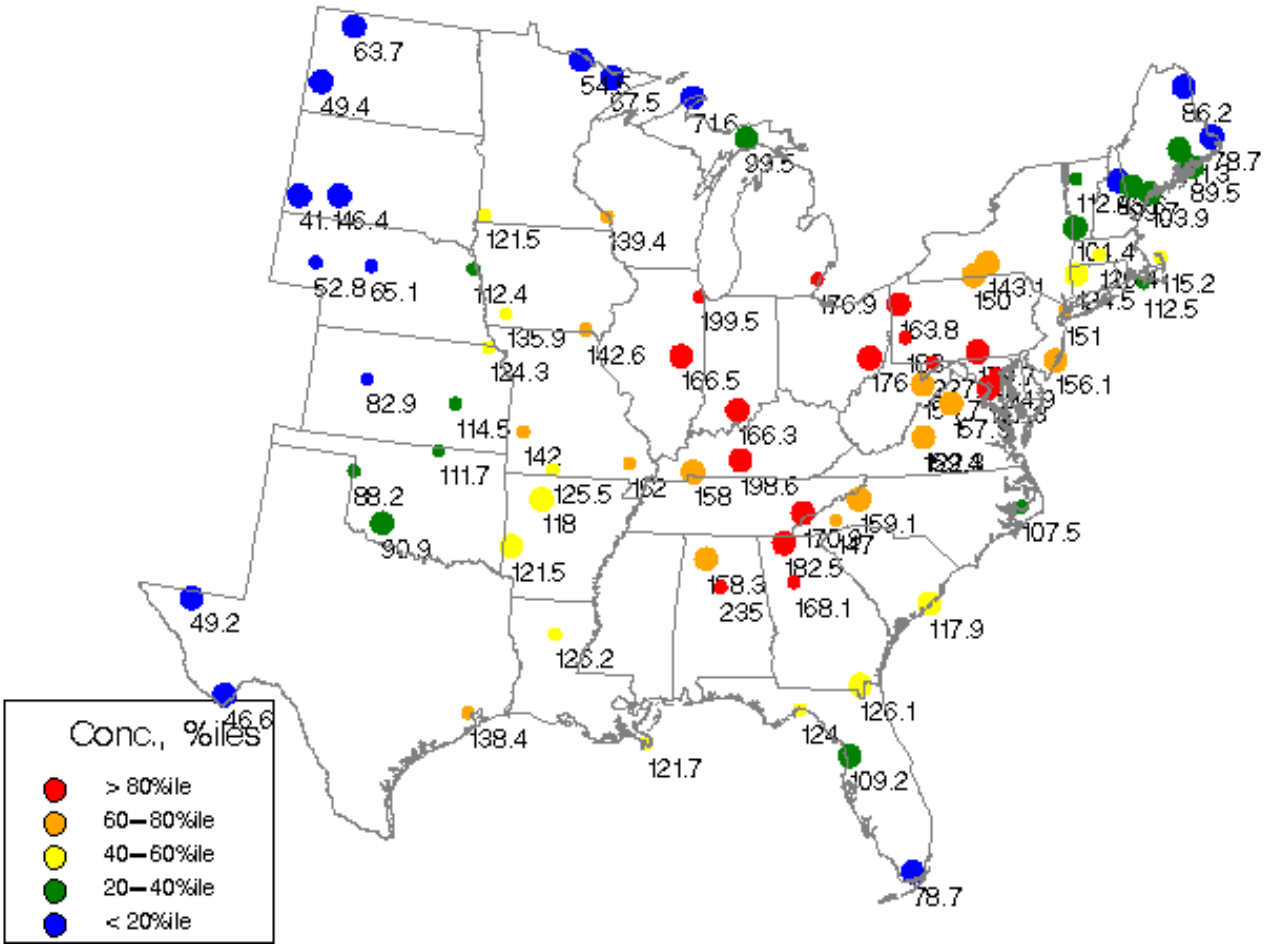


Figure 29. Baseline Visibility Levels for 20% Worst Days (2000 – 2004), units: Mm^{-1}

Initially, the baseline (2000 – 2004) visibility condition values were derived using the average for the 20% worst and 20% best days for each year, as reported on the VIEWS website: http://vista.cira.colostate.edu/views/Web/IMPROVE/SummaryData.aspx . These values were calculated using the original IMPROVE equation for reconstructed light extinction.

Three changes were made to the baseline calculations to produce a new set of values. First, the reconstructed light extinction equation was revised by the IMPROVE Steering Committee in 2005. The new IMPROVE equation was used to calculate updated baseline values.

Second, due to sampler problems, the 2002-2004 data for Boundary Waters were invalid for certain chemical species. (Note, sulfate and nitrate data were valid.) A "substituted" data set was developed by using values from Voyageurs for the invalid species.

Third, LADCO identified a number of days during 2000-2004 where data capture at the Class I monitors was incomplete (Kenski, 2007b). The missing data cause these days to be excluded from the baseline calculations. However, the light extinction due to the remaining measured species is significant (i.e., above the 80th percentile). It makes sense to include these days in the baseline calculations, because they are largely dominated by anthropogenic sources. (Only one of these days is driven by high organic carbon, which might indicate non-anthropogenic aerosol from wildfires.) As seen in Table 3, inclusion of these days in the baseline calculation results in a small, but measurable, effect on the baseline values (i.e., values increase from 0.2 to 0.8 dv).

Table 3. Average of 20% worst days, with and without missing data days

	Average Worst Day DV, per RHR	Average Worst Day DV, with Missing Data Days	Difference
BOWA	19.59	19.86	0.27
ISLE	20.74	21.59	0.85
SENE	24.16	24.38	0.22
VOYA	19.27	19.48	0.21

A summary of the initial and updated baseline values for the Class I areas in northern Michigan and northern Minnesota are presented in Table 4. The updated baseline values reflect the most current, complete understanding of visibility impairing effects and, as such, will be used for SIP planning purposes.

Table 4. Summary of visibility metrics (deciviews) for northern Class I areas

Old IMPROVE Equation (Cite: VIEWS, November 2005)									
		20% Worst Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**	**2018 URI Value**	**Natural Conditions**
Voyageurs		18.50	18.00	19.00	19.20	17.60	18.46	16.74	11.09
BWCA		19.85	19.99	19.68	19.73	17.65	19.38	17.47	11.21
Isle Royale		20.00	22.00	20.80	19.50	19.10	20.28	18.17	11.22
Seney		22.60	24.90	24.00	23.80	22.60	23.58	20.73	11.37
		20% Best Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**		**Natural Conditions**
Voyageurs		6.30	6.20	6.70	7.00	5.40	6.32		3.41
BWCA		5.90	6.52	6.93	6.67	5.61	6.33		3.53
Isle Royale		5.70	6.40	6.40	6.30	5.30	6.02		3.54
Seney		5.80	6.10	7.30	7.50	5.80	6.50		3.69
New IMPROVE Equation (Cite: VIEWS, March 2006)									
		20% Worst Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**	**2018 URI Value**	**Natural Conditions**
Voyageurs		19.55	18.57	20.14	20.25	18.87	19.48	17.74	12.05
BWCA		20.20	20.04	20.76	20.13	18.18	19.86	17.94	11.61
Isle Royale		20.53	23.07	21.97	22.35	20.02	21.59	19.43	12.36
Seney		22.94	25.91	25.38	24.48	23.15	24.37	21.64	12.65
		20% Best Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**		**Natural Conditions**
Voyageurs		7.01	7.12	7.53	7.68	6.37	7.14		4.26
BWCA		6.00	6.92	7.00	6.45	5.77	6.43		3.42
Isle Royale		6.49	7.16	7.07	6.99	6.12	6.77		3.72
Seney		6.50	6.78	7.82	8.01	6.58	7.14		3.73

Notes: (1) BWCA values for 2002 - 2004 reflect "substituted" data.
(2) New IMPROVE equation values include Kenski, 2007 adjustment for missing days

URI = uniform rate of improvement

As noted above, the goal of the visibility program is to achieve natural conditions. Initially, the natural conditions values for each Class I area were taken directly from EPA guidance (EPA, 2003). These values were calculated using the original IMPROVE equation. This equation was revised by the IMPROVE Steering Committee in 2005, and the new IMPROVE equation was used to calculate updated natural conditions values. The updated values are reported on the VIEWS website.

A summary of the initial and updated natural conditions values are presented in Table 4. The updated natural conditions values (based on the new IMPROVE equation) will be used for SIP planning purposes.

Data Variability: For the four northern Class I areas, the most important $PM_{2.5}$ chemical species are ammonium sulfate, ammonium nitrate, and organic carbon. The contribution of these species on the 20% best and 20% worst visibility days (based on 2000 – 2004 data) is provided in Figure 30. For the 20% worst visibility days, the contributions are: sulfate = 35-55%, nitrate = 25-30%, and organic carbon = 12-22%. Although the chemical composition is similar, sulfate increases in importance from west to east and concentrations are highest at Seney (the easternmost site). It should also be noted that sulfate and nitrate contribute more to light extinction than to $PM_{2.5}$ mass because of their hygroscopic properties.

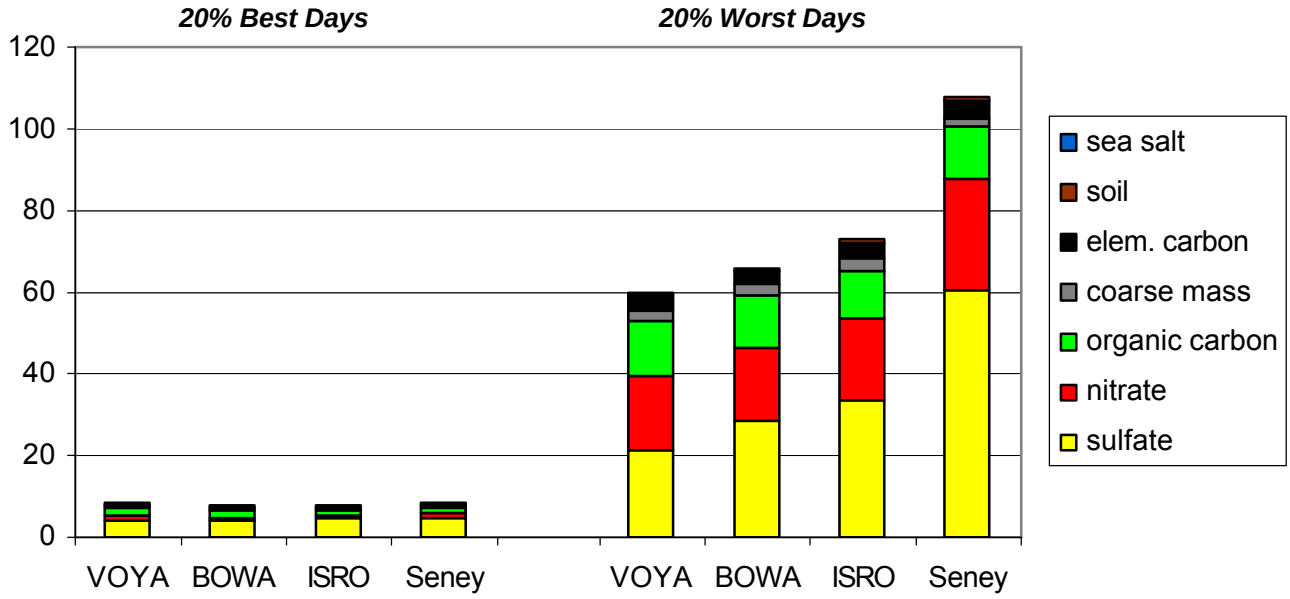


Figure 30. Chemical composition of light extinction for 20% best visibility days (left) and 20% worst visibility days (right) in terms of Mm^{-1}

Analysis of $PM_{2.5}$ mass and chemical species for rural IMPROVE (and IMPROVE-protocol) sites in the eastern U.S. showed a high degree of correlation between $PM_{2.5}$-mass, sulfate, and nitrate levels (see Figure 31). The Class I sites in northern Michigan and northern Minnesota, in particular, are highly correlated for $PM_{2.5}$ mass, sulfates, and organic carbon mass (AER, 2004).

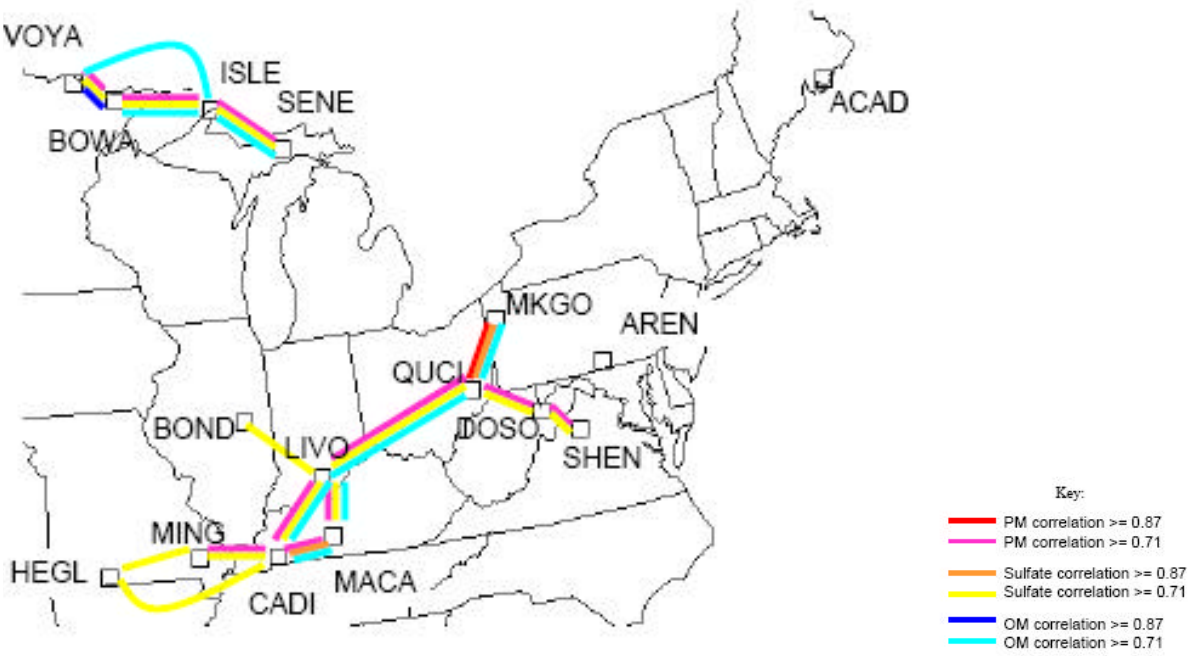


Figure 31. Correlations among IMPROVE (and IMPROVE-protocol) monitoring sites in Eastern U.S.

Long-term trends at Boundary Waters (the only regional site with a sufficient data record) show significant decreases in total $PM_{2.5}$ (-0.005 ug/year) and SO4 (-0.04 ug/year) and an increase in NO3 (+0.01 ug/year). These $PM_{2.5}$ and SO4 trends are generally consistent with long-term trends at other IMPROVE sites in the eastern U.S., which have shown widespread decreases in SO4 and $PM_{2.5}$ (DeBell, et al, 2006). Detecting changes in nitrate has been hampered by uncertainties in the IMPROVE data for particular years and, thus, this estimate should be considered tentative.

Haze in the Midwest Class I areas has no strong seasonal pattern. Poor visibility days occur throughout the year, as indicated in Figure 32. (Note, in contrast, other parts of the country, such as Shenandoah National Park in Virginia, show a strong tendency for the worst air quality days to occur in the summer months.) This figure and Figure 33 (which presents the monthly average light extinction values based on all sampling days) also show that sulfate and organic carbon concentrations are higher in the summer, and nitrate concentrations are higher in the winter, suggesting the importance of different sources and meteorological conditions at different times of the year.

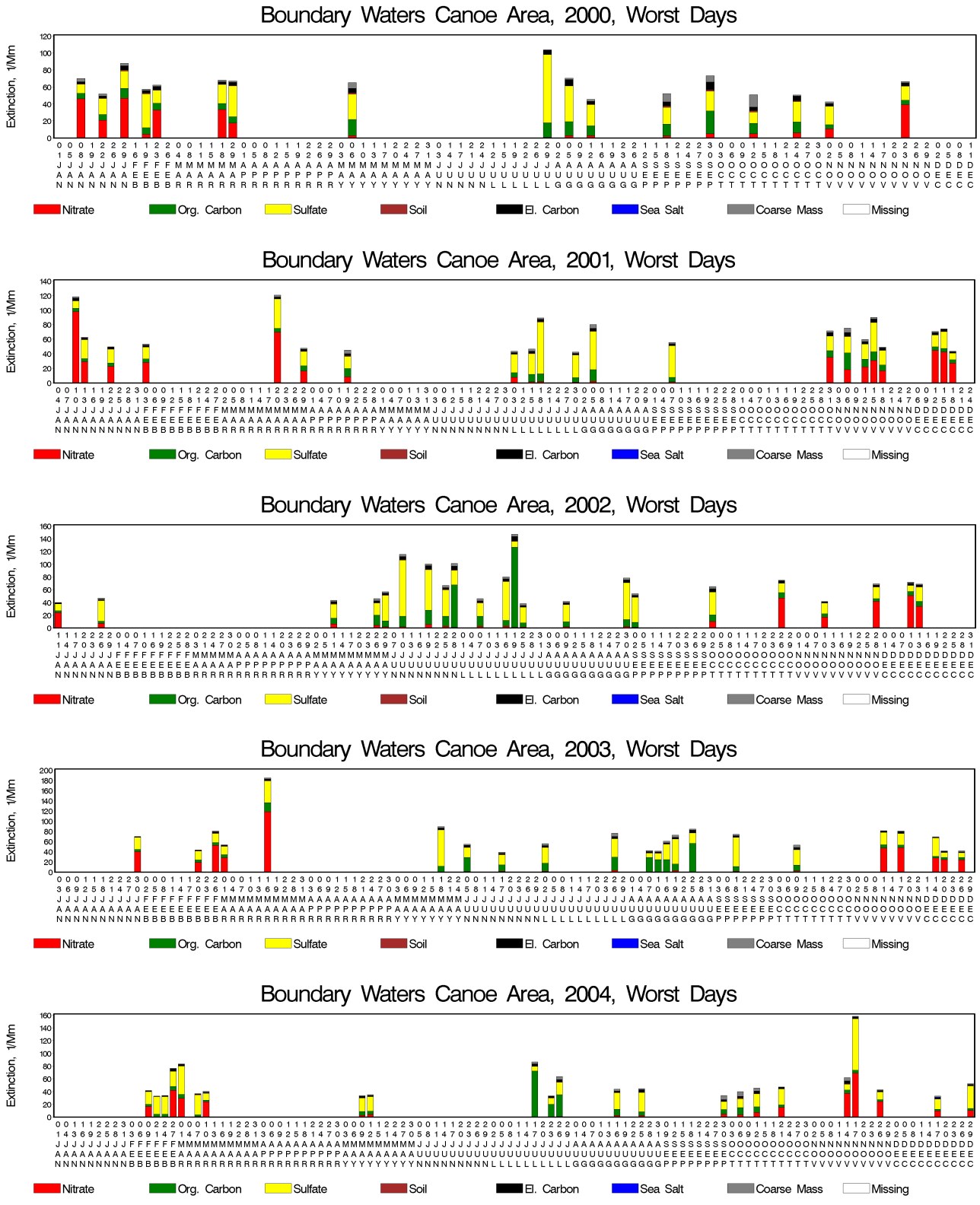


Figure 32. Daily light extinction values for 20% worst days at Boundary Waters (2000 – 2004)

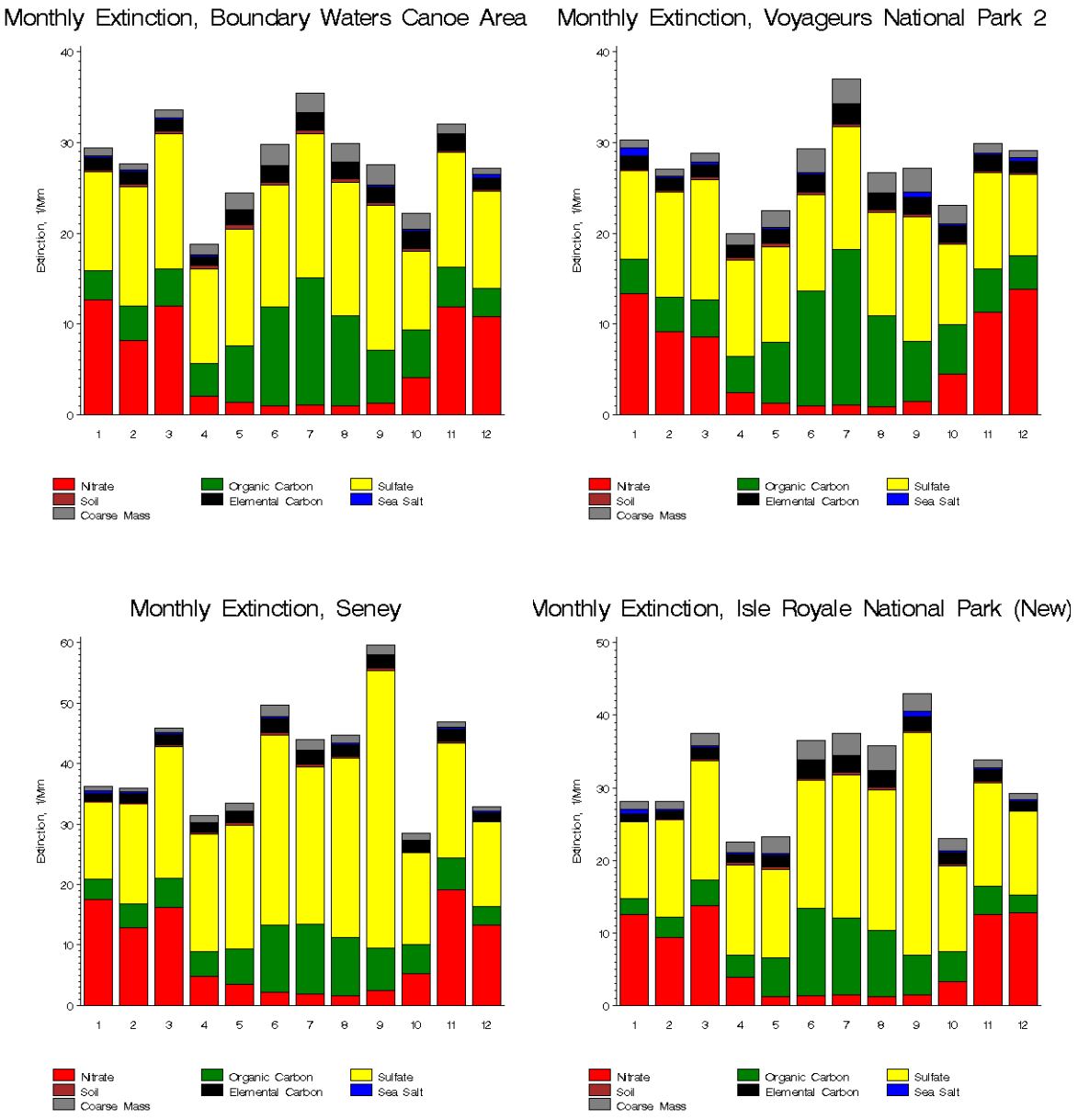


Figure 33. Monthly average light extinction values for northern Class I areas

Precursor Sensitivity: Results from two analyses using thermodynamic equilibrium models provide information on the effect of changes in precursor concentrations on $PM_{2.5}$ concentrations (and, in turn, visibility levels) in the northern Class I areas. First, a preliminary analysis using data collected at Seney indicated that $PM_{2.5}$ there is most sensitive to reductions in sulfate, but is also sensitive to reductions in nitric acid (Blanchard, 2004).

Second, an analysis was performed using data from the Midwest ammonia monitoring network for a site in Minnesota -- Great River Bluffs, which is the closest ammonia monitoring site to the northern Class I areas (Blanchard, 2005b). Figure 34 shows $PM_{2.5}$ concentrations as a function of sulfate, nitric acid (HNO3), and ammonia (NH3). Reductions in sulfate (i.e., movement to the left of baseline value [represented by the red star]), as well as reductions in nitric acid (i.e., movement downward) and NH3 (i.e., movement to the left), result in lower $PM_{2.5}$ concentrations. Thus, reductions in sulfate, nitric acid, and ammonia will lower $PM_{2.5}$ concentrations and improve visibility in the northern Class I areas.

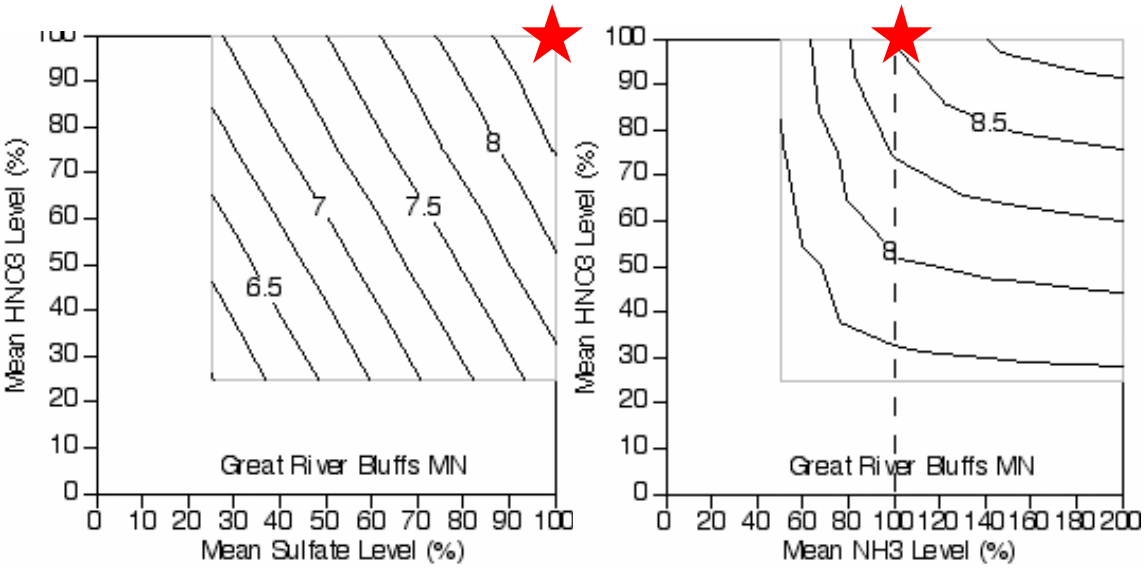


Figure 34. Predicted $PM_{2.5}$ mass concentrations at Great River Bluffs, MN as functions of changes in sulfate, nitric acid, and ammonia

Meteorology and Transport: The role of meteorology in haze is complex. Wind speed and wind direction govern the movement of air masses from polluted areas to the cleaner wilderness areas. As noted above, increasing humidity increases the efficiency with which sulfate and nitrate aerosols scatter light. Temperature and humidity together govern whether ammonium nitrate can form from its precursor gases, nitric acid and ammonia. Temperature and sunlight also play an indirect role in emissions of biogenic organic species that condense to form particulate organic matter; emissions increase in the summer daylight hours.

Trajectory analyses were performed to understand transport patterns for the 20% worst and 20% best visibility days. The composite results for the four northern Class I areas are provided in Figure 35. The orange areas are where the air is most likely to come from, and the green areas are where the air is least likely to come from. As can be seen, bad air days are generally associated with transport from regions located to the south, and good air days with transport from Canada.

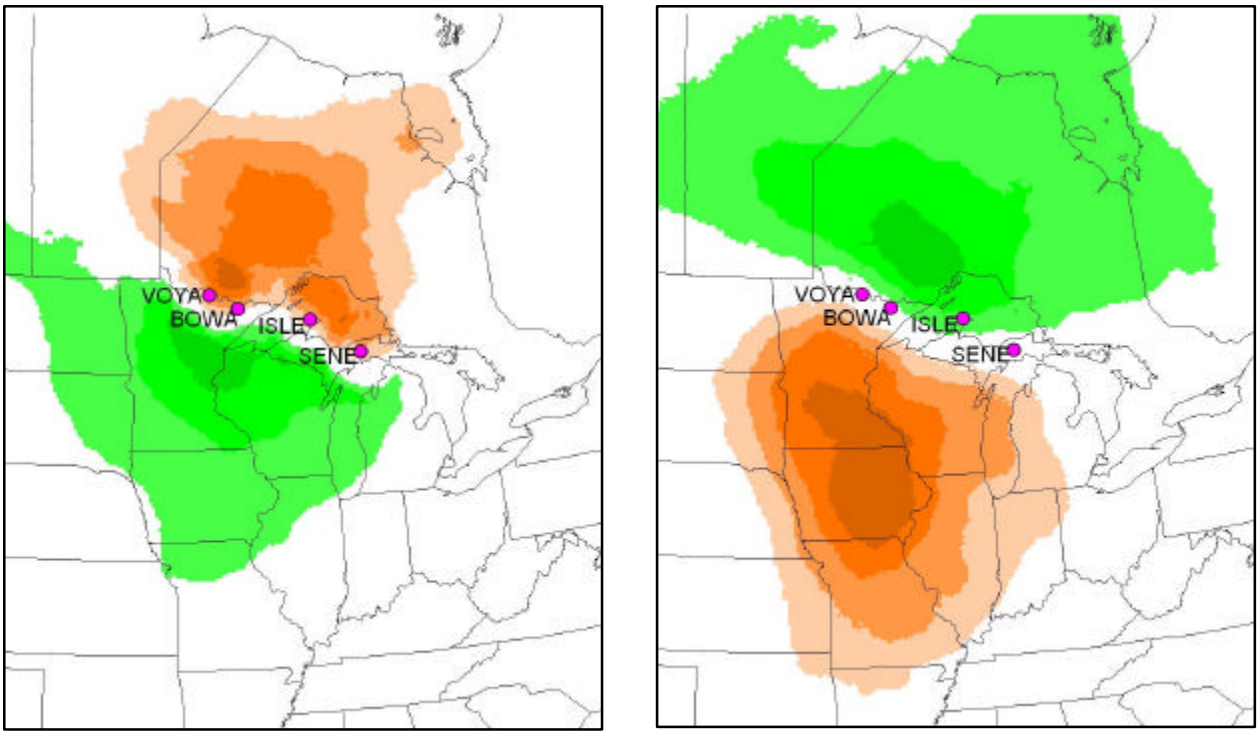


Figure 35. Composite back trajectories for light extinction- 20% best visibility days (left) and 20% worst visibility days (right) (2000 – 2005)

Source Culpability: Air quality data analyses (including the trajectory analyses above) and dispersion modeling were used to provide information on source region and source sector contributions to regional haze in the northern Class I areas (see MRPO, 2008). Based on this information, the most important contributing states are Michigan, Minnesota, and Wisconsin, as well as Missouri, North Dakota, Iowa, Indiana and Illinois (see, for example, Figure 35 above). The most important contributing pollutants and source sectors are SO2 emissions from electrical generating units (EGUs) and certain non-EGUs, which lead to sulfate formation, and NOx emissions from a variety of source types (e.g., motor vehicles), which lead to nitrate formation. Ammonia emissions from livestock waste and fertilizer applications are also important, especially for nitrate formation.

A source apportionment study was performed using monitoring data from Boundary Waters and statistical analysis methods (DRI, 2005). The study shows that a large portion of $PM_{2.5}$ mass consists of secondary, regional impacts, which cannot be attributed to individual facilities or sources (e.g., secondary sulfate, secondary nitrate, and secondary organic aerosols). Industrial sources contribute about 3-4% and mobile sources about 4-7% to $PM_{2.5}$ mass.

A special study was performed in Seney to identify sources of organic carbon (Sheesley, et al, 2004). As seen in Figure 36, the highest $PM_{2.5}$ concentrations occurred during the summer, with organic carbon being the dominant species. The higher summer organic carbon concentrations were attributed mostly to secondary organic aerosols of biogenic origin because of the lack of primary emission markers, and concentrations of know biogenic-related species (e.g., pinonic acid – see Figure 36) were also high during the summer.

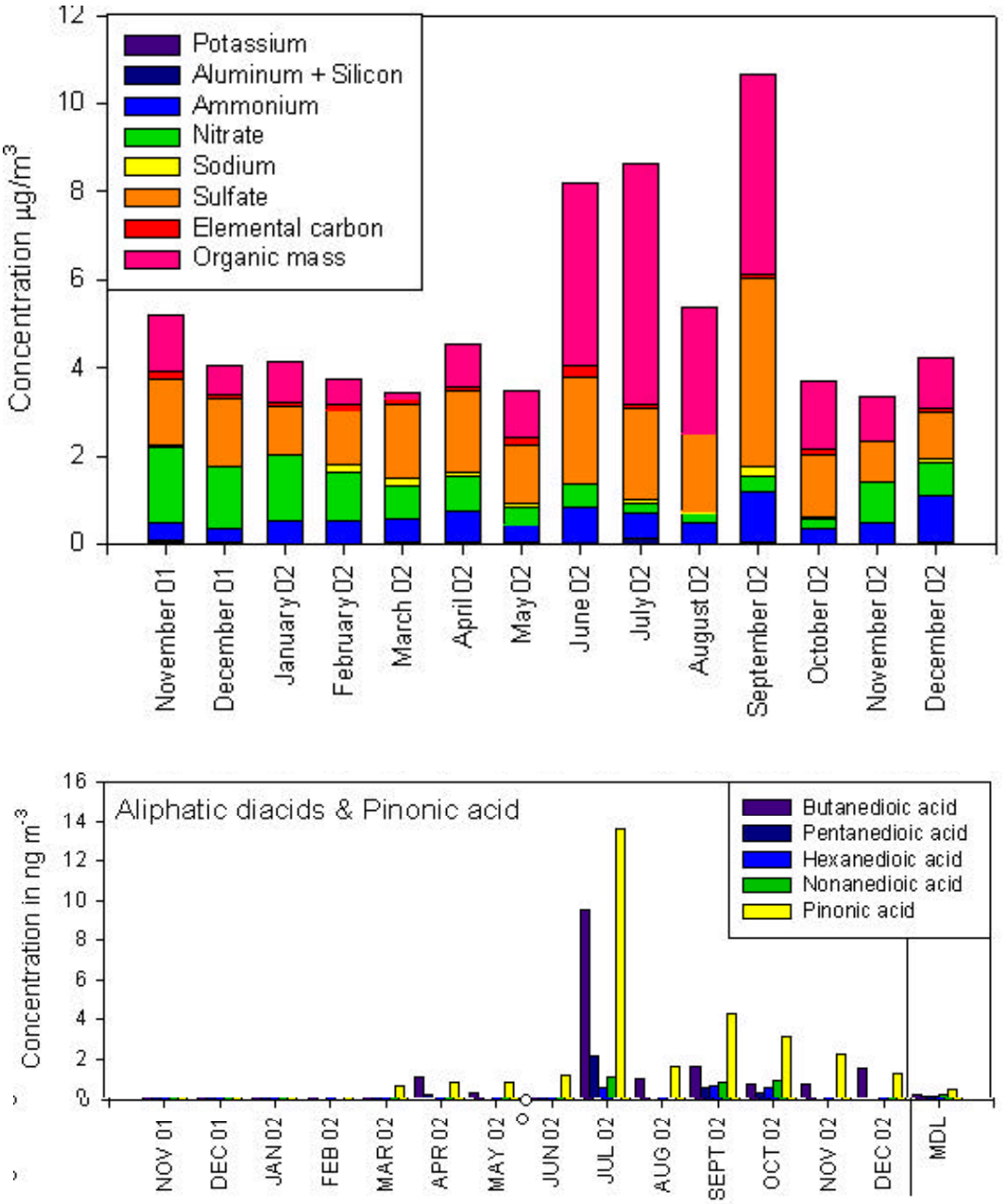


Figure 36. Monthly concentrations of $PM_{2.5}$ species (top), and secondary and biogenic-related organic carbon species in Seney (bottom)

Although the Seney study showed that biomass burning was a relatively small contributor to organic carbon on an annual average basis, episodic impacts are apparent (see, for example, high organic carbon days in Figure 32). To assess further whether burning is a significant contributor to visibility impairment in the northern Class I areas, the $PM_{2.5}$ chemical speciation data were examined for days with high organic carbon and elemental carbon concentrations, which are indicative of biomass burning impacts. Only a handful of such days were identified:

Table 5. Days with high OC and EC concentrations in northern Class I areas

Site	2000	2001	2002	2003	2004
Voyageurs	---	---	Jun 1	Aug 25	Jul 17
			Jun 28		
			Jul 19		
Boundary Waters	---	---	Jun 28	Aug 25	Jul 17
			Jul 19		
Isle Royale	---	---	Jun 1	Aug 25	---
			Jun 28		
Seney	---	---	Jun 28	---	---

Back trajectories on these days point mostly to wildfires in Canada. Elimination of these high organic carbon concentration days has a small effect in lowering the baseline visibility levels in the northern Class I areas (i.e., Minnesota Class I areas change by about 0.3 deciviews and Michigan Class I areas change by less than 0.2 deciviews). This suggests that fire activity, although significant on a few days, is on average a relatively small contributor to visibility impairment in the northern Class I areas.

In summary, these analyses show that organic carbon in the northern Class I is largely uncontrollable.

Section 3.0 Air Quality Modeling

Air quality models are relied on by federal and state regulatory agencies to support their planning efforts. Used properly, models can assist policy makers in deciding which control programs are most effective in improving air quality, and meeting specific goals and objectives. For example, models can be used to conduct "what if" analyses, which provide information for policy makers on the effectiveness of candidate control programs.

The modeling analyses were conducted in accordance with EPA's modeling guidelines (EPA, 2007a). Further details of the modeling are provided in two protocol documents: LADCO, 2007a and LADCO, 2007b.

This section reviews the development and evaluation of the modeling system used for the multi-pollutant analyses. Application of the modeling system (i.e., attainment demonstration for ozone and $PM_{2.5}$, and reasonable progress assessment for haze) is covered in the following sections.

3.1 Selection of Base Year

Two base years were used in the modeling analyses: 2002 and 2005. EPA's modeling guidance recommends using 2002 as the baseline inventory year, but also allows for use of an alternative baseline inventory year, especially a more recent year. Initially, LADCO conducted modeling with a 2002 base year (i.e., Base K/Round 4 modeling, which was completed in 2006). A decision was subsequently made to conduct modeling with a 2005 base year (i.e., Base M/Round 5, which was completed in 2007). As discussed in the previous section, 2002 and 2005 both had above normal ozone conducive conditions, although 2002 was more severe compared to 2005. Examination of multiple base years provides for a more complete technical assessment. Both sets of model runs are discussed in this document.

3.2 Future Years of Interest

To address the multiple attainment requirements for ozone and $PM_{2.5}$, and reasonable progress goals for regional haze, several future years are of interest:

- 2008 Planning year for ozone basic nonattainment areas (attainment date 2009)[8]
- 2009 Planning year for ozone moderate nonattainment areas and $PM_{2.5}$ nonattainment areas (attainment date 2010)
- 2012 Planning year for ozone moderate nonattainment areas and $PM_{2.5}$ nonattainment areas, with 3-year extension (attainment date 2013)
- 2018 First milestone year for regional haze planning

[8] According to USEPA's ozone implementation rule (USEPA, 2005), emission reductions needed for attainment must be implemented by the beginning of the ozone season immediately preceding the area's attainment date. The PM2.5 implementation rule contains similar provisions – i.e., emission reductions should be in place by the beginning of the year preceding the attainment date (USEPA, 2007c). The logic for requiring emissions reductions by the year (or season) immediately preceding the attainment year follows from language in the Clean Air Act, and the ability for an area to receive up to two 1-year extensions. Therefore, emissions in the year preceding the attainment year should be at a level that is consistent with attainment. It also follows that the year preceding the attainment year should be modeled for attainment planning purposes.

Detailed emissions inventories were developed for 2009 and 2018. To support modeling for other future years, less rigorous emissions processing was conducted (e.g., 2012 emissions were estimated for several source sectors by interpolating between 2009 and 2018 emissions).

3.3 Modeling System

The air quality analyses were conducted with the CAMx model, with emissions and meteorology generated using EMS (and CONCEPT) and MM5, respectively. The selection of CAMx as the primary model is based on several factors: performance, operator considerations (e.g., ease of application and resource requirements), technical support and documentation, model extensions (e.g., 2-way nested grids, process analysis, source apportionment, and plume-in-grid), and model science. CAMx model set-up for Base M and Base K is summarized below:

Base M (2005)	Base K (2002)
• CAMx v4.50	* CAMx 4.30
• CB05 gas phase chemistry	* CB-IV with updated gas-phase chemistry
• SOA chemistry updates	* No SOA chemistry updates
• AERMOD dry deposition scheme	* Wesley-based dry deposition
• ISORROPIA inorganic chemistry	• ISORROPIA inorganic chemistry
• SOAP organic chemistry	• SOAP organic chemistry
• RADM aqueous phase chemistry	• RADM aqueous phase chemistry
• PPM horizontal transport	• PPM horizontal transport

3.4 Domain/Grid Resolution

The National RPO grid projection was used for this modeling. A subset of the RPO domain was used for the LADCO modeling. For $PM_{2.5}$ and haze, the large eastern U.S. grid at 36 km (see box on right side of Figure 36) was used. A $PM_{2.5}$ sensitivity run was also performed for this domain at 12 km. For ozone, the smaller grid at 12 km (see shaded portion of the box on the right side of Figure 37) was used for most model runs. An ozone sensitivity run was also performed with a 4km sub-grid over the Lake Michigan area and Detroit/Cleveland.

The vertical resolution in the air quality model consists of 16 layers extending up to 15 km, with higher resolution in the boundary layer.

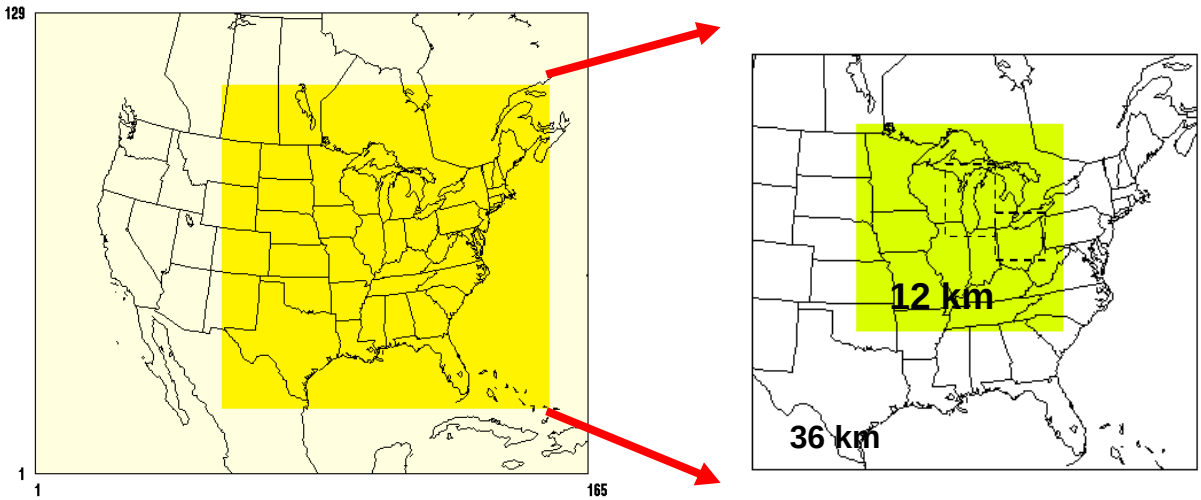


Figure 37. Modeling grids – RPO domain (left) and LADCO modeling domain (right)

3.5 Model Inputs: Meteorology

Meteorological inputs were derived using the Fifth-Generation NCAR/Penn State Meteorological Model (MM5) – version 3.6.3 for the years 2001–2003, and version 3.7 for the year 2005. The MM5 modeling domains are consistent with the National RPO grid projections (see Figure 38).

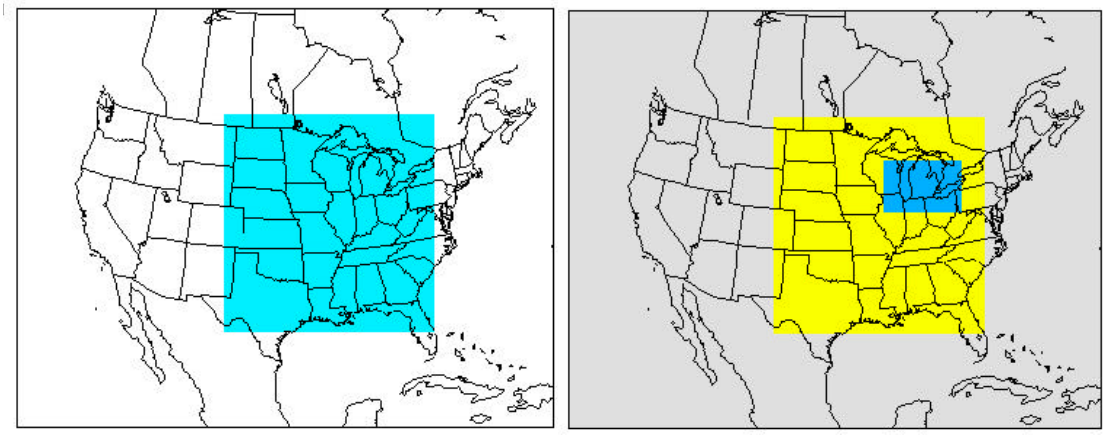


Figure 38. MM5 modeling domain for 2001-2003 (left) and 2005 (right)

The annual 2002 36 km MM5 simulation was completed by Iowa DNR. The 36/12 km 2-way nested simulation for the summers of 2001, 2002, and 2003 were conducted jointly by Illinois EPA and LADCO. The 36 km non-summer portion of the annual 2003 simulation was conducted by Wisconsin DNR. The annual 2005 36/12 km (and summer season 4 km) MM5 modeling was completed by Alpine Geophysics. Wisconsin DNR also completed 36/12 km MM5 runs for the summer season of 2005.

Model performance was assessed quantitatively with the METSTAT tool from Environ. The metrics used to quantify model performance include mean observation, mean prediction, bias, gross error, root mean square error, and index of agreement. Model performance metrics were calculated for several sub-regions of the modeling domain (Figure 39) and represent hourly spatial averages of multiple monitor locations. Additional analysis of rainfall is done on a monthly basis.

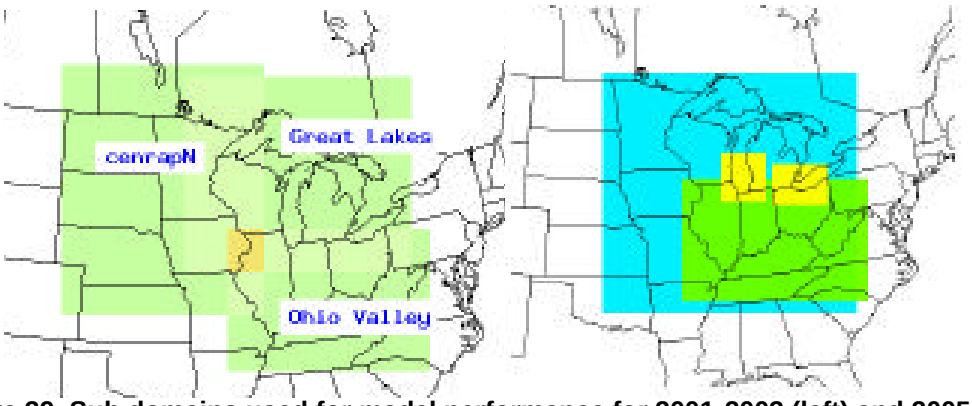


Figure 39. Sub-domains used for model performance for 2001-2003 (left) and 2005 (right)

A summary of the performance evaluation results for the meteorological modeling is provided below. Further details are provided in two summary reports (LADCO, 2005 and LADCO, 2007c).

Temperature: The biggest issue with the performance in the upper Midwest is the existence of a cool diurnal temperature bias in the winter and warm temperature bias over night during the summer (see Figure 40). These features are common to other annual MM5 simulations for the central United States and do not appear to adversely affect model performance.

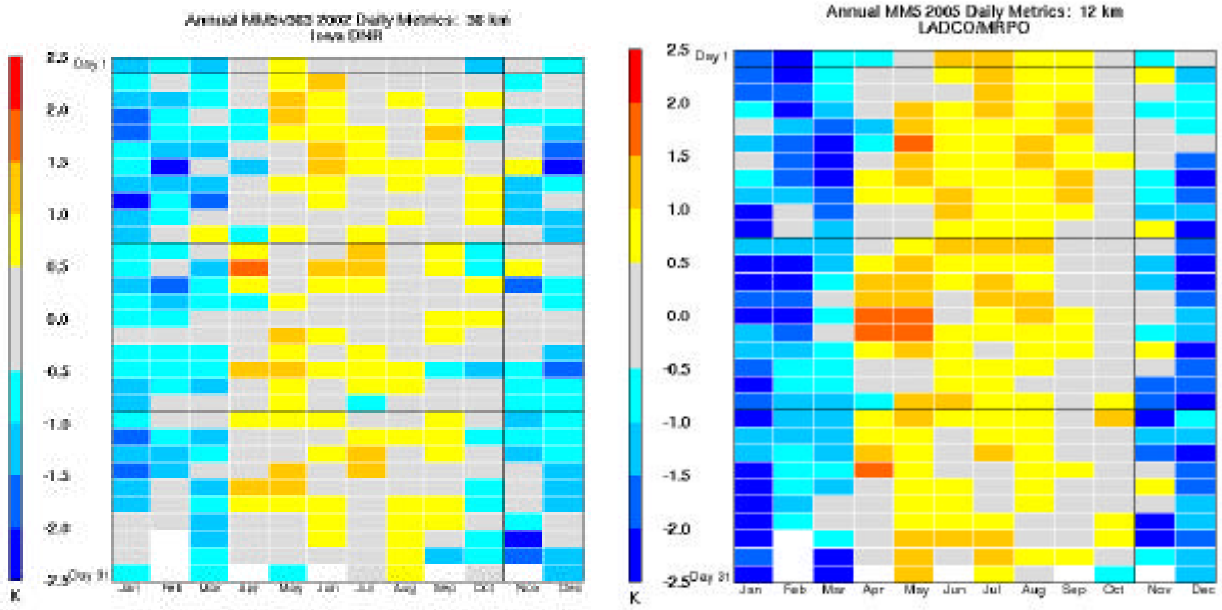


Figure 40. Daily temperature bias for 2002 (left) and 2005 (right) with hotter colors (yellow/orange/red) representing overestimates and cooler colors (blues) representing underestimates

Note: months are represented from left to right (January to December) and days are represented from top to bottom (1 to 30(31) – i.e., upper left hand corner is January 1 and lower right hand corner is December 31

Wind Fields: The wind fields are generally good. Wind speed bias is less than 0.5 m/sec and wind speed error is consistently between 1.0 and 1.5 m/sec. Wind direction error is generally within 15-30 degrees.

Mixing Ratio: The mixing ratio (a measure of humidity) is over-predicted in the late spring and summer months, and mixing ratio error is highest during this period. There is little bias and error during the cooler months when there is less moisture in the air.

Rainfall: The modeled and observed rainfall totals show good agreement spatially and in terms of magnitude in the winter, fall, and early spring months. There are, however, large over-predictions of rainfall in the late spring and summer months (see Figure 41). These over-predictions are seen spatially and in magnitude over the entire domain, particularly in the Southeast United States, and are likely due to excessive convective rainfall being predicted in MM5. This over-prediction of rainfall in MM5 does not necessarily translate into over-prediction of wet deposition in the photochemical model. CAMx does not explicitly use the convective and non-convective rainfall output by MM5, but estimates wet scavenging by hydrometeors using cloud, ice, snow, and rain water mixing ratios output by MM5. Nevertheless, this could have an effect on model performance for $PM_{2.5}$, as discussed in Section 3.7, and may warrant further attention.

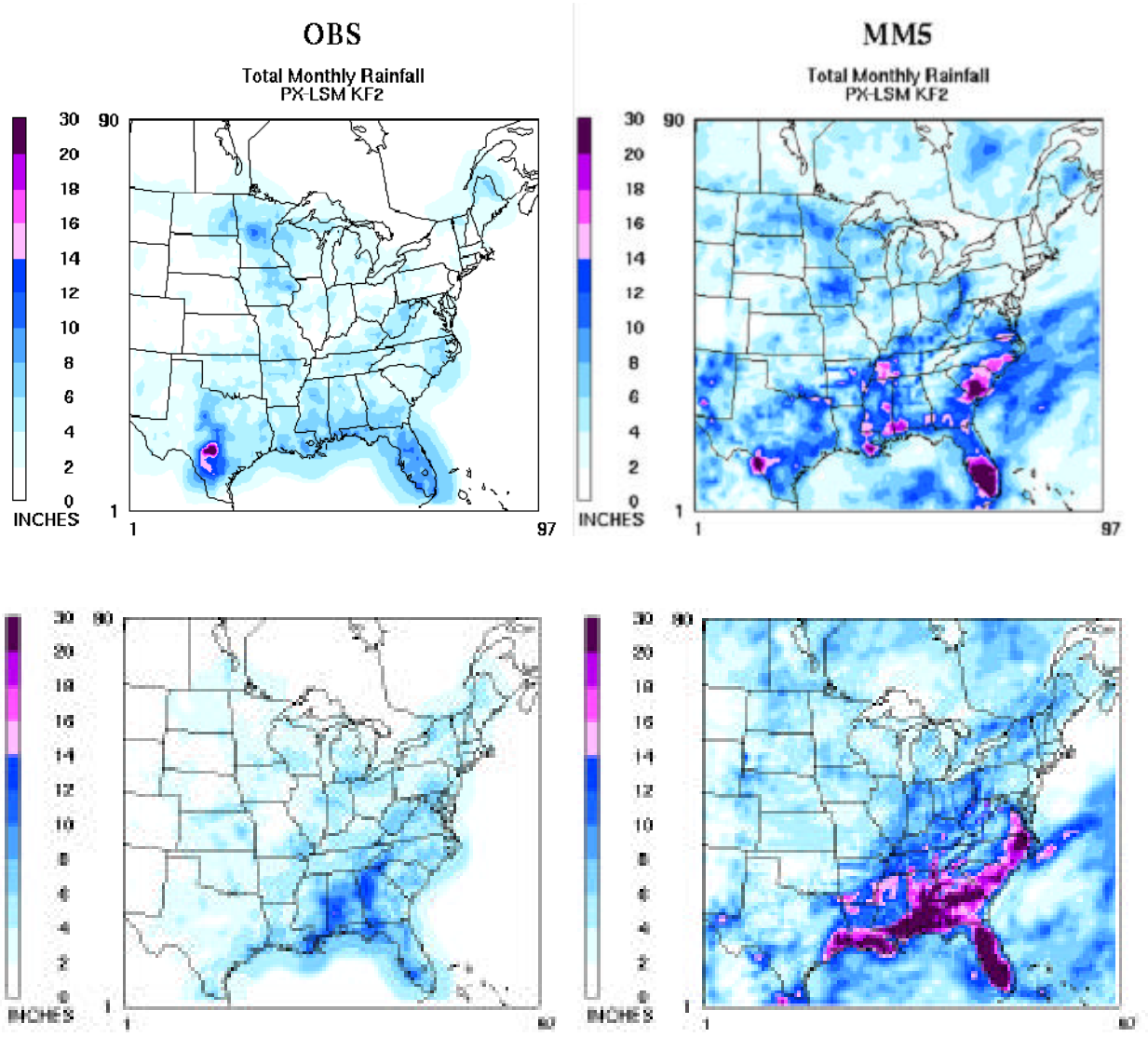


Figure 41. Comparison of observed (left column) and modeled (right column) monthly rainfall for July 2002 (top) and July 2005 (bottom)

3.6 Model Inputs: Emissions

Emission inventories were prepared for two base years: 2002 (Base K) and 2005 (Base M), and several future years: 2008, 2009, 2012, and 2018. Further details of the emission inventories are provided in two summary reports (LADCO, 2006a and LADCO, 2008a) and the following pages of the LADCO web site:

http://www.ladco.org/tech/emis/basek/BaseK_Reports.htm
http://www.ladco.org/tech/emis/r5/round5_reports.htm

For on-road, nonroad, ammonia, and biogenic sources, emissions were estimated by models. For the other sectors (point sources, area sources, and MAR [commercial marine, aircraft, and railroads]), emissions were prepared using data supplied by the LADCO States and other RPOs.

Base Year Emissions: State and source sector emission summaries for 2002 (Base K) and 2005 (Base M) are compared in Figure 42. Additional detail is provided in Tables 6a (all sectors – tons per day) and 6b (EGUs – tons per year).

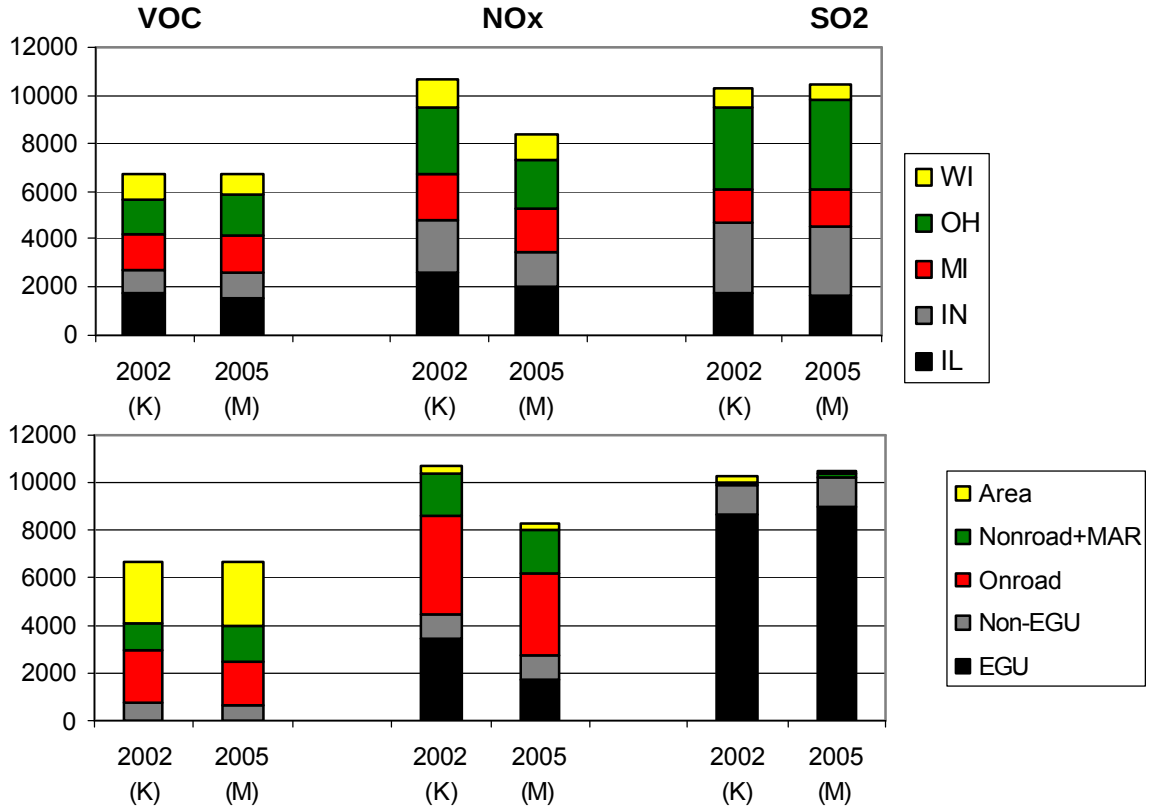


Figure 42. Base K and Base M emissions for 5-state LADCO region by state (top) and source sector (bottom), units: tons per summer weekday

A summary of the base year emissions by sector for the LADCO States is provided below.

	VOC	Base M	BaseK	Base M	BaseK	BaseK	Base M		NOx	Base M	BaseK	Base M	BaseK	BaseK	Base M		SOX	Base M	BaseK	Base M	BaseK	BaseK	Base M		PM2.5	Base M	BaseK	Base M	BaseK	BaseK	Base M
July	2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018
Nonroad																															
IL	224	321	164	257	149	130	213		324	333	263	275	224	154	155		31	33	5	5	0.6	0.4	0.4			30		24			14
IN	125	195	94	160	95	95	128		178	191	142	158	141	141	89		17	19	3	3	3	0.3	0.2			17		13			7
MI	348	414	307	350	276	222	271		205	239	159	197	133	93	112		19	22	3	3	0.5	0.3	0.3			22		18			11
OH	222	356	161	294	145	126	238		253	304	195	246	162	109	135		23	29	4	5	0.5	0.3	0.4			27		22			13
WI	214	238	194	203	175	140	157		145	157	114	129	97	69	77		13	15	2	2	0.3	0.2	0.2			14		12			7
5-State Total	1133	1524	920	1264	840	713	1007		1105	1224	873	1005	757	566	568		103	118	17	18	4.9	1.5	1.5			110		89			52
U.S. Total	8463	9815	5442	8448		5244	6581		6041	9060	6057	8120		5832	5100		505	654	117	153		104	13			573		750			475
MAR																															
IL	10	11	10	10	10	10	6		277	246	201	228	195	186	165		0	22	0	19	0	0	17			7		6			4
IN	5	5	5	5	5	5	3		123	93	89	87	87	84	65		0.2	8	0.2	7	0.2	0.2	6			2		2			2
MI	7	7	7	7	7	8	7		114	87	112	82	111	110	65		0.6	21	0.7	14	0.7	0.8	8			3		3			2
OH	8	7	8	7	8	8	5		177	134	128	126	126	122	94		0.4	14	0.3	12	0.3	0.3	10			4		4			2
WI	4	4	4	4	4	4	3		79	58	59	54	59	57	41		12.7	8	9.5	6	9.5	8.7	5			2		2			1
5-State Total	34	34	34	33	34	35	24		770	618	589	577	578	559	430		13.9	73	10.7	58	10.7	10	46			18		17			11
U.S. Total	307	317	321	157	329	346	334		4968	4515	4002	1813	3964	3919	3812		620	512	509	122	509	503	290			147		57			165
OtherArea																															
IL	679	675	688	594	700	738	582		62	48	68	48	70	73	49		11	11	12	16	12	13	16			40		64			69
IN	354	391	365	358	373	398	384		62	56	65	58	67	69	59		158	32	150	32	151	153	32			2		2			2
MI	518	652	516	562	520	541	549		49	49	52	50	53	54	51		71	29	68	29	68	68	28			111		114			120
OH	546	604	550	506	558	593	487		50	93	59	108	60	62	108		22	6	34	15	35	35	14			19		35			34
WI	458	315	467	290	474	506	293		32	37	34	37	34	35	37		9	17	9	13	10	10	13			11		12			12
5-State Total	2555	2637	2586	2310	2625	2776	2295		255	283	278	301	284	293	304		271	95	273	105	276	279	103			183		227			237
U.S. Total	17876	21093	18638	18683		20512	24300		3856	4899	4100	4220		4418	5357		2075	2947	2062	2559		2189	2709			2735		2621			2570
On-Road																															
IL	446	341	314	268	260	197	151		890	748	578	528	474	300	201			9		4			3			13		10			6
IN	405	282	237	235	193	150	138		703	541	425	402	313	187	173			11		3			2			9		7			2
MI	522	351	335	269	303	217	163		926	722	680	501	619	385	204			14		4			3			12		9			3
OH	574	680	365	424	340	238	242		1035	934	609	693	512	270	274			18		4			4			16		12			4
WI	238	175	144	119	117	88	68		481	457	303	322	226	118	138			9		2			2			8		6			2
5-State Total	2185	1829	1395	1315	1213	890	762		4035	3402	2595	2446	2144	1260	990			61		17			14			58		44			17
U.S. Total	14263				7825				23499				13170																		
EGU																															
IL	9	7	8	6	8	9	7		712	305	227	275	244	231	224		1310	1158	944	958	789	810	869			13		34			77
IN	6	6	6	6	7	6	6		830	393	406	370	424	283	255		2499	2614	1267	1033	1263	1048	1036			16		73			74
MI	12	6	11	4	11	12	4		448	393	218	242	219	247	243		1103	1251	1022	667	1031	1058	725			15		25			29
OH	5	4	6	5	7	7	6		1139	408	330	280	322	271	285		3131	3405	1463	1326	994	701	983			28		94			80
WI	3	5	3	2	4	4	3		293	213	146	165	139	147	177		602	545	512	460	492	500	435			0		22			25
5-State Total	35	28	34	23	37	38	26		3422	1712	1327	1332	1348	1179	1184		8645	8973	5208	4444	4569	4117	4048			72		248			285
U.S. Total	214	140	195	124	197	215	138		14371	10316	7746	7274	7721	7007	6095		31839	34545	20163	16903	17629	14727	14133			685		1131			1571
Non-EGU																															
IL	313	221	286	218	305	350	258		356	330	334	218	338	343	235		373	423	251	335	257	249	346			16		17			19
IN	150	130	160	137	170	199	167		238	179	212	175	216	225	178		292	218	270	216	274	290	180			35		36			44
MI	123	116	115	119	122	139	140		216	240	208	242	214	229	271		162	158	166	148	171	185	163			20		21			25
OH	77	84	75	87	79	90	104		177	175	157	166	160	167	178		240	289	231	288	210	216	293			27		28			33
WI	88	84	97	87	104	120	106		98	97	91	93	92	94	81		163	156	154	152	155	156	85			0		0.1			0.1
5-State Total	751	635	733	648	780	898	775		1085	1021	1002	894	1020	1058	943		1230	1244	1072	1139	1067	1096	1067			98		102			121
U.S. Total	4087	3877	4409		4700	5378			6446	6730	6129		6435	6952			5759	5630	6093		6340	6970						1444			1777
IL	1681	1576	1470	1353	1432	1434	1217		2621	2010	1671	1572	1545	1287	1029		1725	1656	1212	1337	1059	1072	1251			119		155			189
IN	1045	1009	867	901	843	853	826		2134	1453	1339	1250	1248	989	819		2966	2902	1690	1294	1691	1492	1256			81		133			131
MI	1530	1546	1291	1311	1239	1139	1134		1958	1730	1429	1314	1349	1118	946		1356	1495	1260	865	1271	1312	927			183		190			190
OH	1432	1735	1165	1323	1137	1062	1082		2831	2048	1478	1619	1342	1001	1074		3416	3761	1732	1650	1240	953	1304			121		195			166
WI	1005	821	909	705	878	862	630		1128	1019	747	800	647	520	551		800	750	687	635	667	675	540			35		54			47
5-State Total	6693	6687	5702	5593	5529	5350	4889		10672	8260	6664	6555	6131	4915	4419		10263	10564	6581	5781	5928	5504	5280			539		727			723

Table 6b. EGU Emissions for Midwest States (2018)						
	Heat Input (MMBTU/year)	**Scenario**	**SO2 (tons/year)**	**SO2 (lb/MMBTU)**	**NOx (tons/year)**	**NOx (lb/MMBTU)**
IL	**980,197,198**	**2001 - 2003 (average)**	**362,417**	**0.74**	**173,296**	**0.35**
		IPM 2.1.9	241,000		73,000	
	1,310,188,544	IPM3.0 (base)	277,337	0.423	70,378	0.107
		IPM3.0 - will do	140,296	0.214	62,990	0.096
		IPM3.0 - may do	140,296	0.214	62,990	0.096
IN	**1,266,957,401**	**2001 - 2003 (average)**	**793,067**	**1.25**	**285,848**	**0.45**
		IPM 2.1.9	377,000		95,000	
	1,509,616,931	IPM3.0 (base)	361,835	0.479	90,913	0.120
		IPM3.0 - will do	417,000	0.552	94,000	0.125
		IPM3.0 - may do	417,000	0.552	94,000	0.125
MI	**756,148,700**	**2001 - 2003 (average)**	**346,959**	**0.92**	**132,995**	**0.35**
		IPM 2.1.9	399,000		100,000	
	1,009,140,047	IPM3.0 (base)	244,151	0.484	79,962	0.158
		IPM3.0 - will do	244,151	0.484	79,962	0.158
		IPM3.0 - may do	244,151	0.484	79,962	0.158
OH	**1,306,296,589**	**2001 - 2003 (average)**	**1,144,484**	**1.75**	**353,255**	**0.54**
		IPM 2.1.9	216,000		84,000	
	1,628,081,545	IPM3.0 (base)	316,883	0.389	96,103	0.118
		IPM3.0 - will do	348,000		101,000	
		IPM3.0 - may do	348,000		101,000	
WI	**495,475,007**	**2001 - 2003 (average)**	**191,137**	**0.77**	**90,703**	**0.36**
		IPM 2.1.9	155,000		46,000	
	675,863,447	IPM3.0 (base)	127,930	0.379	56,526	0.167
		IPM3.0 - will do	150,340	0.445	55,019	0.163
		IPM3.0 - may do	62,439	0.185	46,154	0.137
IA	**390,791,671**	**2001 - 2003 (average)**	**131,080**	**0.67**	**77,935**	**0.40**
		IPM 2.1.9	147,000		51,000	
	534,824,314	IPM3.0 (base)	115,938	0.434	59,994	0.224
		IPM3.0 - will do	115,938	0.434	59,994	0.224
		IPM3.0 - may do	100,762	0.377	58,748	0.220
MN	**401,344,495**	**2001 - 2003 (average)**	**101,605**	**0.50**	**85,955**	**0.42**
		IPM 2.1.9	86,000		42,000	
	447,645,758	IPM3.0 (base)	61,739	0.276	41,550	0.186
		IPM3.0 - will do	54,315	0.243	49,488	0.221
		IPM3.0 - may do	51,290	0.229	39,085	0.175
MO	**759,902,542**	**2001 - 2003 (average)**	**241,375**	**0.63**	**143,116**	**0.37**
		IPM 2.1.9	281,000		78,000	
	893,454,905	IPM3.0 (base)	243,684	0.545	72,950	0.163
		IPM3.0 - will do	237,600	0.532	72,950	0.163
		IPM3.0 - may do	237,600	0.532	72,950	0.163
ND	**339,952,821**	**2001 - 2003 (average)**	**145,096**	**0.85**	**76,788**	**0.45**
		IPM 2.1.9	109,000		72,000	
	342,685,501	IPM3.0 (base)	41,149	0.240	44,164	0.258
		IPM3.0 - will do	56,175	0.328	58,850	0.343
		IPM3.0 - may do	56,175	0.328	58,850	0.343
SD	**39,768,357**	**2001 - 2003 (average)**	**12,545**	**0.63**	**15,852**	**0.80**
		IPM 2.1.9	12,000		15,000	
	44,856,223	IPM3.0 (base)	4,464	0.199	2,548	0.114
		IPM3.0 - will do	4,464	0.199	2,548	0.114
		IPM3.0 - may do	4,464	0.199	2,548	0.114

On-road Sources: For 2002, EMS was run by LADCO using VMT and MOBILE6 inputs supplied by the LADCO States. EMS was run to generate 36 days (weekday, Saturday, Sunday for each month) at 36 km, and 9 days (weekday, Saturday, Sunday for June – August) at 12 km. For 2005, CONCEPT was run by a contractor (Environ) using transportation data (e.g., VMT and vehicle speeds) supplied by the state and local planning agencies in the LADCO States and Minnesota for 24 networks. These data were first processed with T3 (Travel Demand Modeling [TDM] Transformation Tool) to provide input files for CONCEPT to calculate link-specific, hourly emission estimates (Environ, 2008). CONCEPT was run with meteorological data for a July and January weekday, Saturday, and Sunday (July 15 – 17 and January 16 – 18). A spatial plot of emissions is provided in Figure 43.

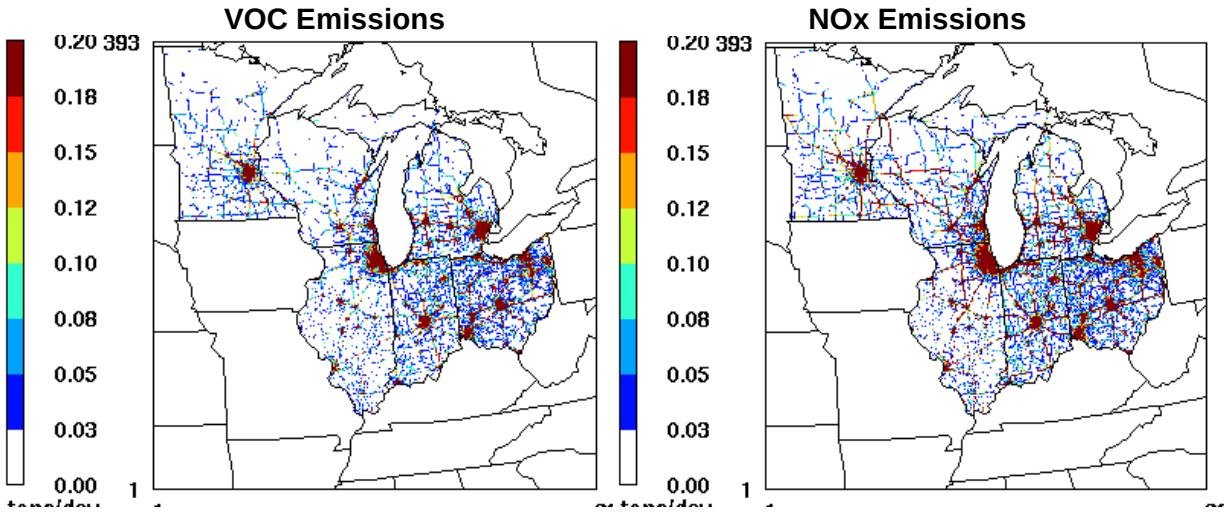


Figure 43. Motor vehicle emissions for VOC (left) and NOx (right) for a July weekday (2005)

Off-road Sources: For 2002 and 2005, NMIM and NMIM2005, respectively, were run by Wisconsin DNR. Additional off-road sectors (i.e., commercial marine, aircraft, and railroads [MAR]) were handled separately. Local data for agricultural equipment, construction equipment, commercial marine, recreational marine, and railroads were prepared by contractors (Environ, 2004, and E.H. Pechan, 2004). For Base M, updated local data for railroads and commercial marine were prepared by a contractor (Environ, 2007b, 2007c). Table 7 compares the Base M 2005 and Base K 2002 emissions. Compared to 2002, the new 2005 emissions reflect substantially lower commercial marine emissions and lower locomotive NOx emissions.

Table 7. Locomotive and commercial marine emissions for the five LADCO States (2002 v. 2005)

	Railroads (TPY)			Commercial Marine (TPY)	
	2002	**2005**		**2002**	**2005**
VOC	7,890	7,625		1,562	828
CO	20,121	20,017		8,823	6,727
NOx	182,226	145,132		64,441	42,336
PM	5,049	4,845		3,113	1,413
SO2	12,274	12,173		25,929	8,637
NH3	86	85		----	----

Area Sources: For 2002 and 2005, EMS was run by LADCO using data supplied by the LADCO States to produce weekday, Saturday, and Sunday emissions for each month. For 2005, special attention was given to two source categories: industrial adhesive and sealant solvents (which were dropped from the inventory to avoid double-counting) and outdoor wood boilers (which were added to the inventory).

Point Sources: For 2002 and 2005, EMS was run by LADCO using data supplied by the LADCO States to produce weekday, Saturday, and Sunday emissions for each month. For EGUs, the annual and summer season emissions were temporalized for modeling purposes using profiles prepared by Scott Edick (Michigan DEQ) based on CEM data.

Biogenics: For Base M, a contractor (Alpine) provided an updated version of the CONCEPT/MEGAN biogenics model. Compared to the previous (EMS/BIOME) emissions, there is more regional isoprene using MEGAN compared to the BIOME estimates used for Base K (see Figure 44). Also, with the secondary organic aerosol updates to the CAMx air quality model, Base M includes emissions for monoterpenes and sesquiterpenes, which are pre-cursors of secondary $PM_{2.5}$ organic carbon mass.

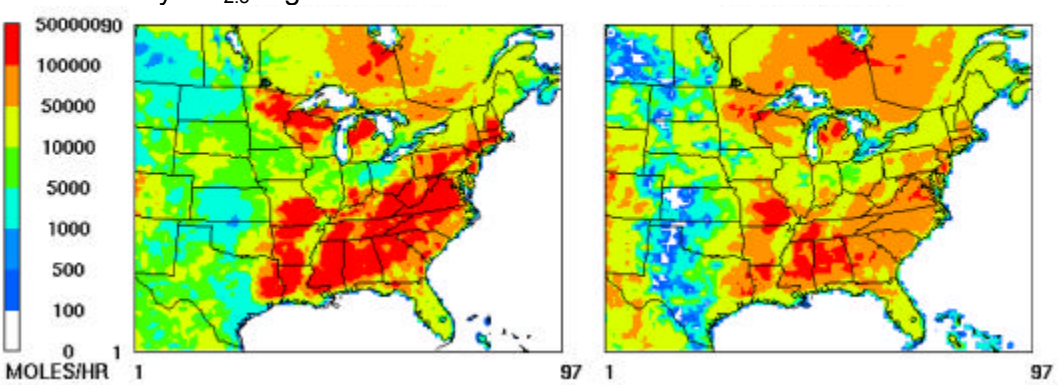


Figure 44. Isoprene emissions for Base M (left) v. Base K (right)

Ammonia: For Base M, the CMU-based 2002 (Base K) ammonia emissions were projected to 2005 using growth factors from the Round 4 emissions modeling. These emissions were then adjusted by applying temporal factors by month based on the process-based ammonia emissions model (Zhang, et al, 2005, and Mansell, et al, 2005). A plot of average daily emissions by state and month is provided in Figure 45. A spatial plot of emissions is provided in Figure 46, which shows high emissions densities in the central U.S.

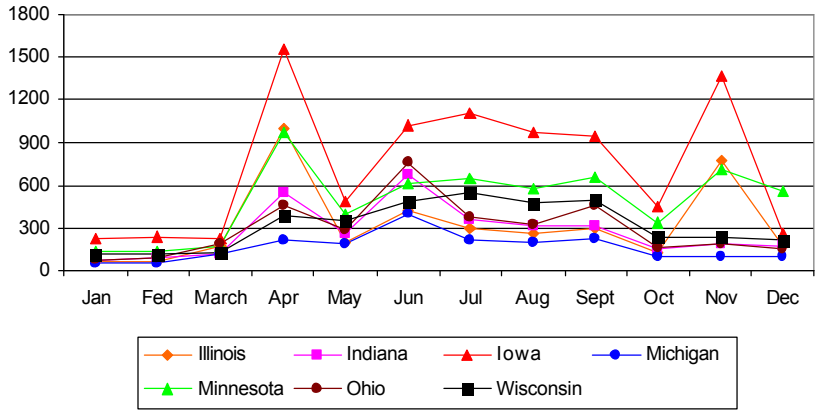


Figure 45. Average daily ammonia emissions for Midwest States by month (2005) - (units: average daily emissions – tons per day)

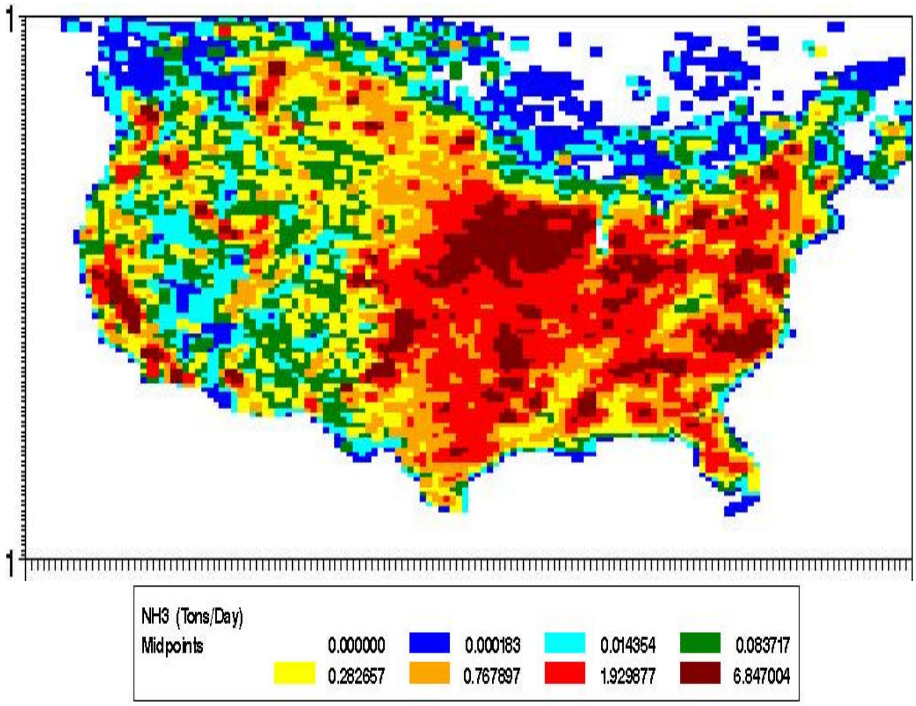


Figure 46. Ammonia emissions for a July weekday (2005) – 12 km modeling domain

Canadian Emissions: For Base M, Scott Edick (Michigan DEQ) processed the 2005 Canadian National Pollutant Release Inventory, Version 1.0 (NPRI). Specifically, a subset of the NPRI data (emissions and stack parameters) relevant to the air quality modeling were reformatted. The resulting emissions represent a significant improvement in the base year emissions.

A spatial plot of point source SO2 and NOx emissions is provided in Figure 47. Additional plots and emission reports are available on the LADCO website (http://www.ladco.org/tech/emis/basem/canada/index.htm).

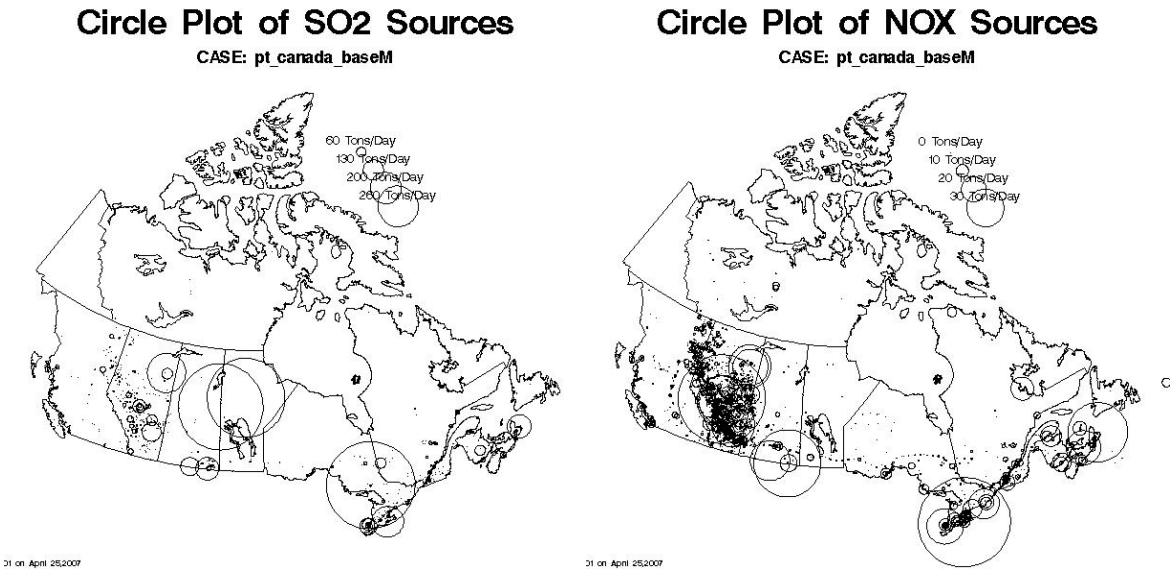


Figure 47. Canadian point source emissions for SO2 (left) and NOx (right)

Fires: For Base K, a contractor (EC/R, 2004) developed a 2001, 2002, and 2003 fire emissions inventory for eight Midwest States (five LADCO states plus Iowa, Minnesota, and Missouri), including emissions from wild fires, prescribed fires, and agricultural burns. Projected emissions were also developed for 2010 and 2018 assuming "no smoke management" and "optimal smoke management" scenarios. An early model sensitivity run showed very little difference in modeled $PM_{2.5}$ concentrations. Consequently, the fire emissions were not included in subsequent modeling runs (i.e., they were not in the Base K or Base M modeling inventories).

Future Year Emissions: Complete emission inventories were developed for several future years: Base K – 2009, 2012, and 2018, and Base M – 2009 and 2018. In addition, 2008 (Base K and Base M) and 2012 (Base M) proxy inventories were estimated based on the 2009 and 2018 data. (Note, the EGU emissions for the Base M 2012 inventory were based on EPA's IPM3.0 modeling.)

Source sector emission summaries for the base years and future years are shown in Figure 48. Additional detail is provided in Tables 6a and 6b.

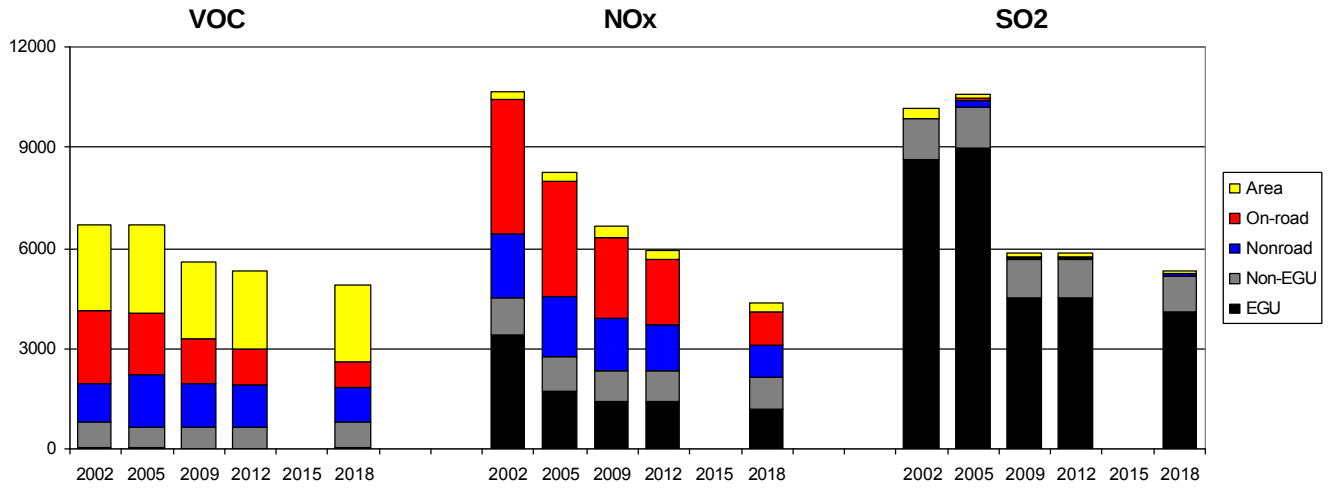


Figure 48. Base year and future year emissions for 5-State LADCO Region (TPD, July weekday)

For on-road, and nonroad, the future year emissions were estimated by models (i.e., EMS/CONCEPT and NMIM, respectively). One adjustment was made to the 2009 and 2018 motor vehicle emission files prepared by Environ with CONCEPT. To reflect newer transportation modeling conducted by CATS for the Chicago area, emissions were increased by 9% in 2009 and 2018. The 2005 base year and adjusted 2009 and 2018 motor vehicle emissions are provided in Table 8.

Table 8. Motor Vehicle Emissions Produced by CONCEPT Modeling (July weekday – tons per day)

Year	State	Sum of CO	Sum of TOG	Sum of NOx	Sum of PM2.5	Sum of SO2	Sum of NH3	Sum of VMT
2005	IL	3,684.3	341.5	748.2	12.9	9.6	35.9	344,087,819.6
	IN	3,384.9	282.0	541.1	8.9	11.1	25.7	245,537,231.9
	MI	4,210.3	351.9	722.0	12.4	13.9	35.3	340,834,025.9
	MN	2,569.1	218.7	380.5	6.3	7.6	17.7	170,024,599.7
	OH	6,113.4	679.8	933.6	16.2	18.8	36.5	360,521,068.6
	WI	2,206.0	175.1	457.5	7.8	9.2	19.7	189,123,964.3
Total		22,168.0	2,049.0	3,782.9	64.5	70.2	170.8	1,650,128,709.9
2009	IL	2,824.4	268.0	527.8	10.1	4.2	38.9	372,132,591.1
	IN	2,839.5	234.9	401.9	6.7	2.8	26.1	249,817,026.3
	MI	3,172.0	269.2	500.9	9.2	4.0	37.1	356,347,010.5
	MN	2,256.8	206.3	307.5	5.1	2.3	21.5	204,443,017.8
	OH	4,619.2	423.7	693.5	11.8	4.7	39.5	387,428,127.2
	WI	1,673.4	119.4	322.1	5.7	2.3	20.6	197,729,964.9
Total		17,385.3	1,521.5	2,753.6	48.7	20.3	183.6	1,767,897,737.8
2018	IL	2,084.7	151.5	200.7	6.3	3.7	43.1	413,887,887.3
	IN	2,217.3	138.4	173.0	4.4	2.6	30.2	288,042,232.1
	MI	2,434.3	163.5	204.1	5.9	3.6	40.5	388,128,431.8
	MN	1,799.6	123.1	137.1	3.6	2.2	24.9	237,022,213.7
	OH	3,361.5	242.5	274.1	6.8	4.0	43.1	421,694,093.4
	WI	1,255.5	68.4	138.5	3.9	2.0	22.2	218,277,167.5
Total		13,152.9	887.5	1,127.5	30.8	18.1	203.9	1,967,052,025.8

For EGUs, future year emissions were based on IPM2.1.9 modeling completed by the RPOs in July 2005 Base K and IPM3.0 completed by EPA in February 2007 for Base M. Several CAIR scenarios were assumed:

Base K
1a: IPM2.1.9, with full trading and banking
1b: IPM2.1.9, with restricted trading (compliance with state-specific emission budgets) and full trading
1d: IPM2.1.9, with restricted trading (compliance with state-specific emission budgets)

Base M
5a: EPA's IPM3.0 was assumed as the future year base for EGUs.
5b: EPA's IPM3.0, with several "will do" adjustments identified by the States. These adjustments should reflect a legally binding commitment (e.g., signed contract, consent decree, or operating permit).
5c: EPA's IPM3.0, with several "may do" adjustments identified by the States. These adjustments reflect less rigorous criteria, but should still be some type of public reality (e.g., BART determination or press announcement).

For other sectors (area, MAR, and non-EGU point sources), the future year emissions for the LADCO States were derived by applying growth and control factors to the base year inventory. These factors were developed by a contractor (E.H. Pechan, 2005 and E.H. Pechan, 2007). For the non-LADCO States, future year emission files were based on data from other RPOs.

Growth factors were based initially on EGAS (version 5.0), and were subsequently modified (for select, priority categories) by examining emissions activity data. Due to a lack of information on future year conditions, the biogenic VOC and NOx emissions, and all Canadian emissions were assumed to remain the constant between the base year and future years.

A "base" control scenario was prepared for each future year based on the following "on the books" controls:

On-Highway Mobile Sources
- Federal Motor Vehicle Emission Control Program, low-sulfur gasoline and ultra-low sulfur diesel fuel
- Inspection - maintenance programs, including IL's vehicle emissions tests (NE IL), IN's vehicle emissions testing program (NW IN), OH's E-check program (NE OH), and WI's vehicle inspection program (SE WI) – note: a special emissions modeling run was done for the Cincinnati/Dayton area to reflect the removal of the state's E-check program and inclusion of low RVP gasoline
- Reformulated gasoline, including in Chicago-Gary,-Lake County, IL,IN; and Milwaukee, Racine, WI

Off-Highway Mobile Sources
- Federal control programs incorporated into NONROAD model (e.g., nonroad diesel rule), plus the evaporative Large Spark Ignition and Recreational Vehicle standards
- Heavy-duty diesel (2007) engine standard/Low sulfur fuel
- Federal railroad/locomotive standards
- Federal commercial marine vessel engine standards

Area Sources (Base M only)
- Consumer solvents
- AIM coatings
- Aerosol coatings
- Portable fuel containers

Power Plants
- Title IV (Phases I and II)
- NOx SIP Call
- Clean Air Interstate Rule

Other Point Sources

- VOC 2-, 4-, 7-, and 10-year MACT standards
- Combustion turbine MACT

Other controls included in the modeling include: consent decrees (refineries, ethanol plants, and ALCOA)[9], NOx RACT in Illinois and Ohio[10], and BART for a few non-EGU sources in Indiana and Wisconsin.

For Base K, several additional control scenarios were considered:

Scenario 2 – "base" controls plus additional controls recommended in LADCO White Papers for stationary and mobile sources

Scenario 3 – Scenario 2 plus additional White Papers for stationary and mobile sources

Scenario 4 – "base" controls plus additional candidate control measures under discussion by State Commissioners

Scenario 5 – "base" controls plus additional candidate control measures identified by the LADCO Project Team

3.7 Basecase Modeling Results

The purpose of the basecase modeling is to evaluate model performance (i.e., assess the model's ability to reproduce the observed concentrations). The model performance evaluation focused on the magnitude, spatial pattern, and temporal of modeled and measured concentrations. This exercise was intended to assess whether, and to what degree, confidence in the model is warranted (and to assess whether model improvements are necessary).

Model performance was assessed by comparing modeled and monitored concentrations. Graphical (e.g., side-by-side spatial plots, time series plots, and scatter plots) and statistical analyses were conducted. No rigid acceptance/rejection criteria were used for this study. Instead, the statistical guidelines recommended by EPA and other modeling studies (e.g., modeling by the other RPOs) were used to assess the reasonableness of the results. The model performance results presented here describe how well the model replicates observed ozone and $PM_{2.5}$ concentrations after a series of iterative improvements to model inputs.

Ozone: Spatial plots are provided for high ozone periods in June 2002 and June 2005 (see Figures 49a and 49b). The plots show that the model is doing a reasonable job of reproducing the magnitude, day-to-day variation, and spatial pattern of ozone concentrations. There is a tendency, however, to underestimate the magnitude of regional ozone levels. This is more apparent with the 2002 modeling; the regional concentrations in the 2005 modeling agree better with observations due to model and inventory improvements.

[9] E.H. Pechan's original control file included control factors for three sources in Wayne County, MI. These control factors were not applied in the regional-scale modeling to avoid double-counting with the State's local-scale analysis for PM2.5

[10] NOx RACT in Wisconsin is included in the 2005 basecase (and EGU "will do" scenario). NOx RACT in Indiana was not included in the modeling inventory.

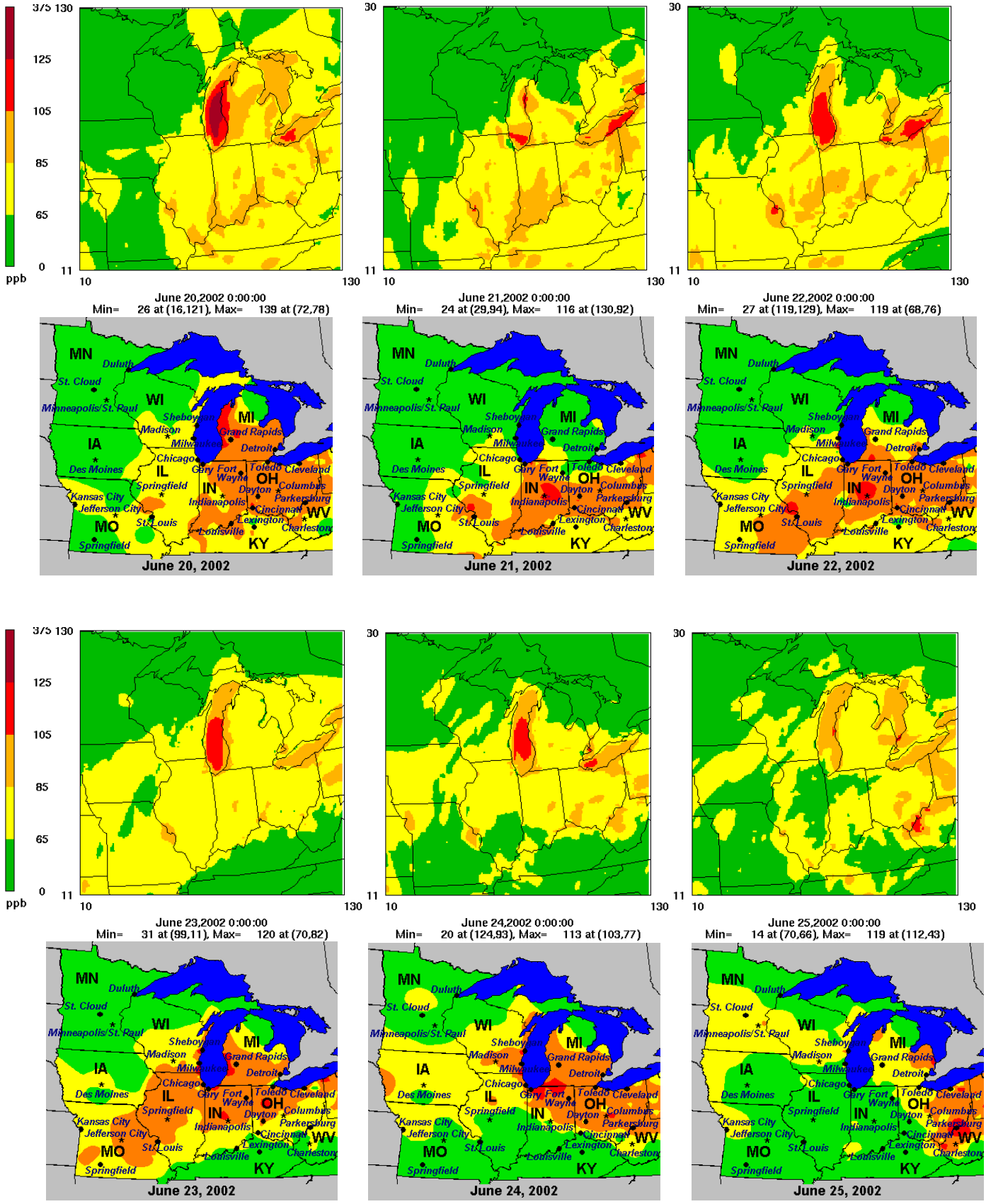


Figure 49a. Modeled (top) v. monitored (bottom) 8-hour ozone concentrations: June 20 – 25, 2002

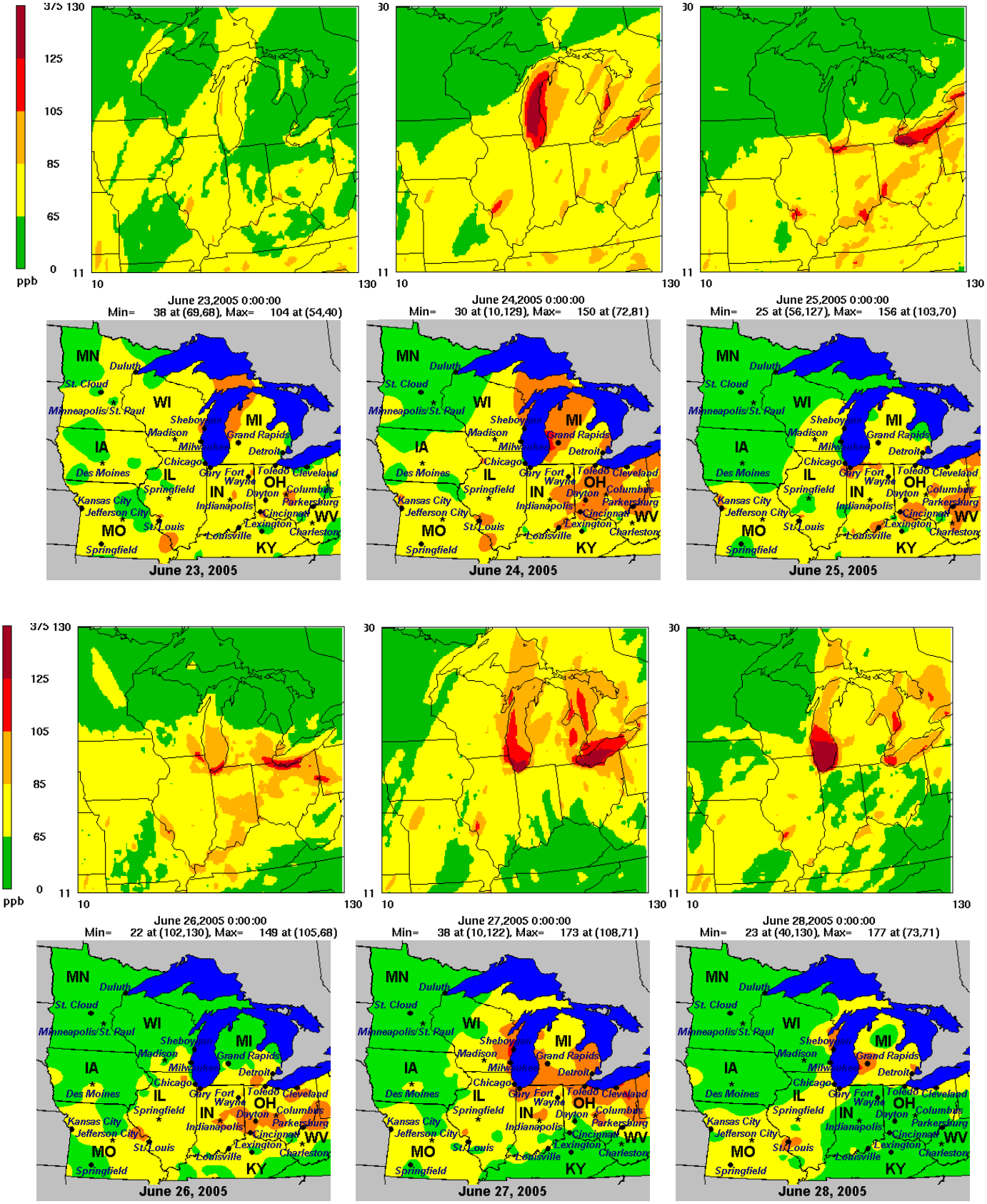


Figure 49b Modeled (top) v. monitored (bottom) 8-hour ozone concentrations: June 23– 28 2005

Standard model performance statistics were generated for the entire 12 km domain, and by day and by monitoring site. The domain-wide mean normalized bias for the 2005 base year is similar to that for the 2002 base year and is generally within 30% (see Figure 50).

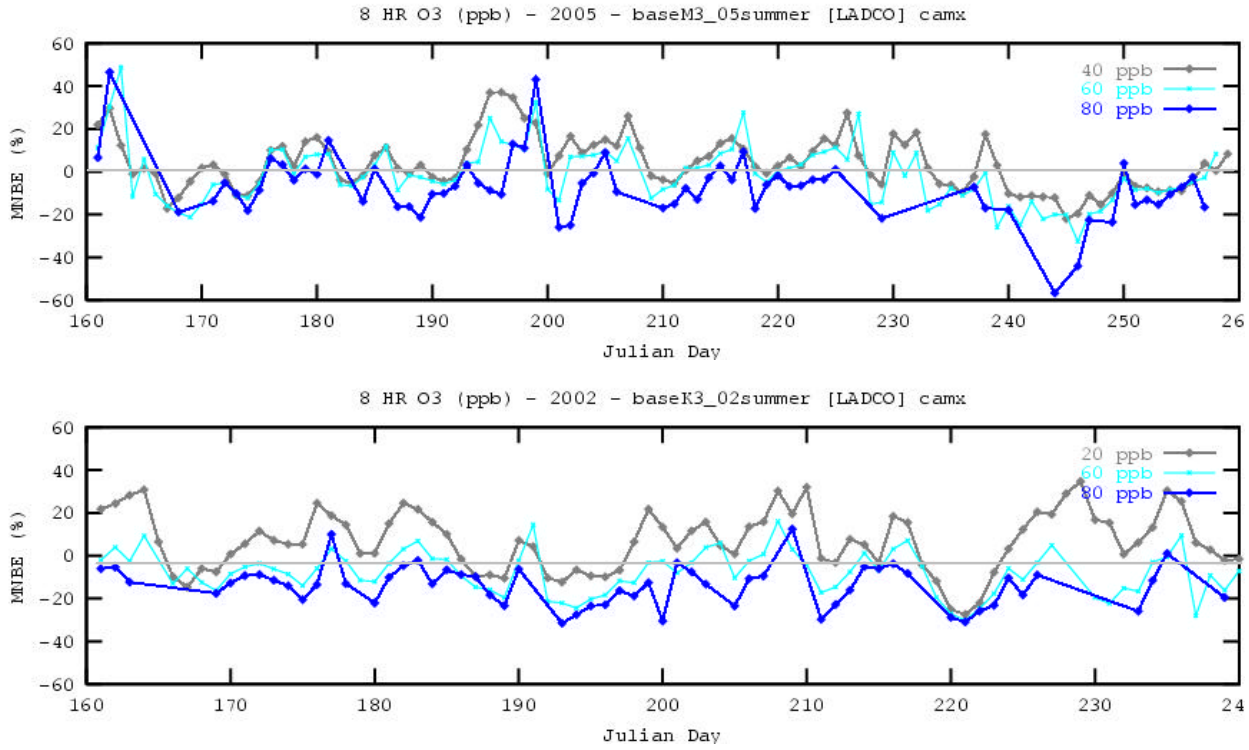


Figure 50. Mean bias for summer 2005 (Base M) and summer 2002 (Base K)

Station-average metrics (over the entire summer) are shown in Figure 51. The bias results further demonstrate the model's tendency to underestimate absolute ozone concentrations.

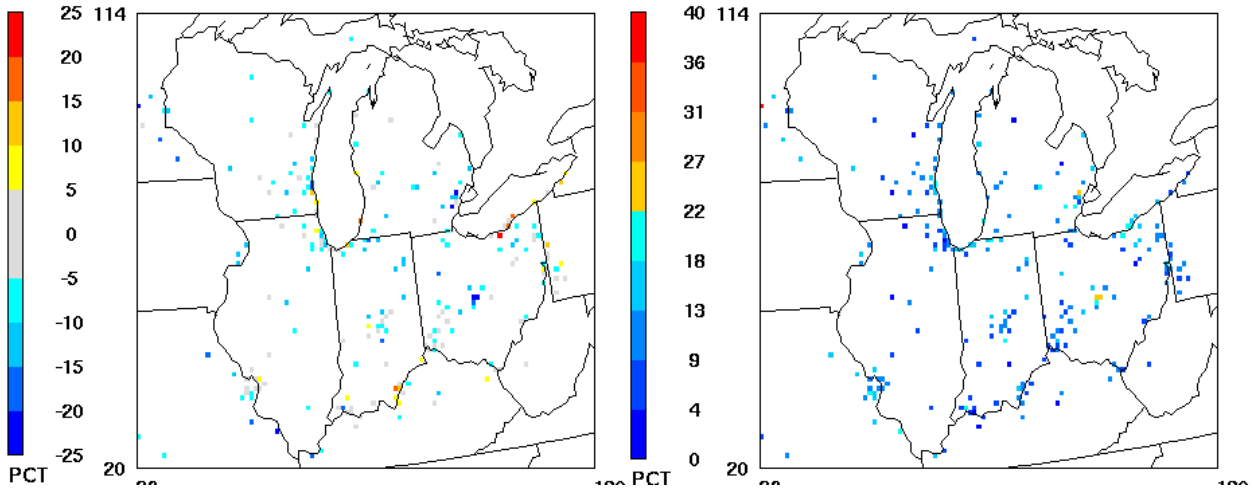


Figure 51. Mean bias (left) and gross error (right) for summer 2005

A limited 4 km ozone analysis was performed by LADCO to address the effect of grid spacing. For this modeling, 4 km grids were placed over Lake Michigan and the Detroit-Cleveland area (see Figure 52). Model inputs included 4 km emissions developed by LADCO (consistent with Base K/Round 4) and the 4 km meteorology developed by Alpine Geophysics.

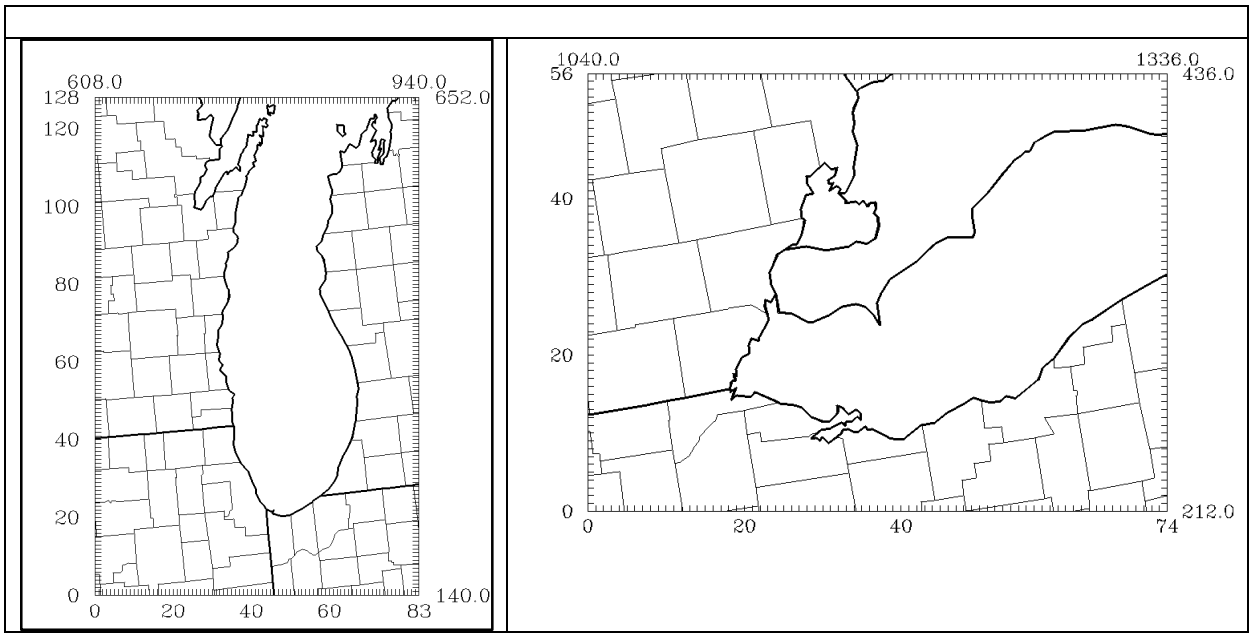


Figure 52. 4 km grids for Lake Michigan region and Detroit-Cleveland region

Hourly time series plots were prepared for several monitors (see Figure 53). The results are similar at 12 km and 4 km, with some site-by-site and day-by-day differences.

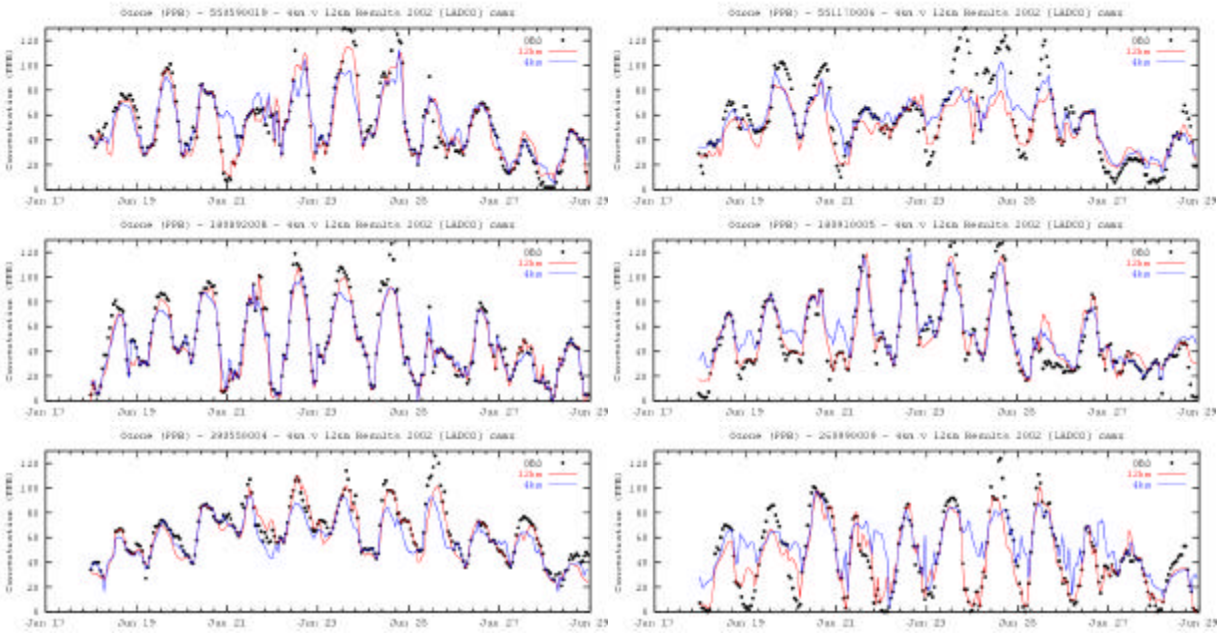
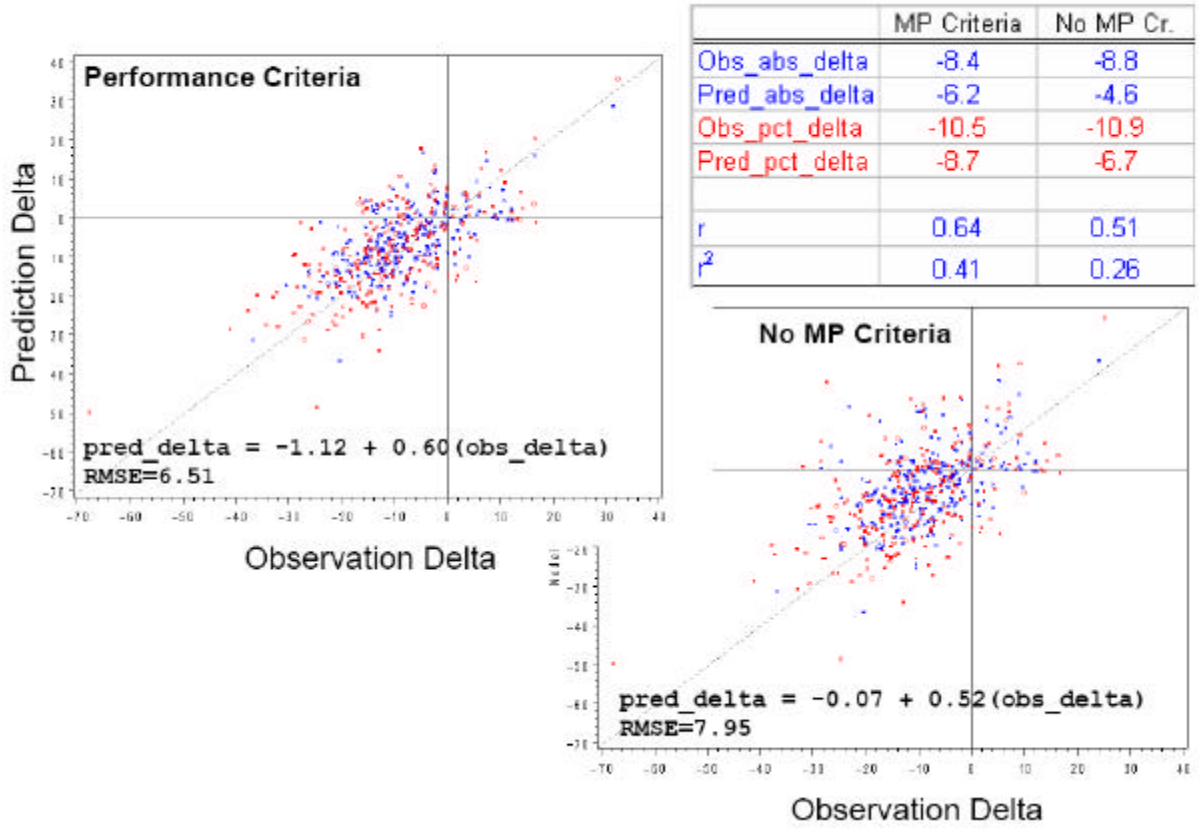


Figure 53. Ozone time series plots for 12 km and 4 km modeling (June 17-29, 2002)

An additional diagnostic analysis was performed to assess the response of the modeling system to changes in emissions (Baker and Kenski, 2007). Specifically, the 2002-to-2005 change in observed ozone concentrations was compared to the change in modeled ozone concentrations based on the 95th percentile(and above) concentration values for each monitor. This analysis was also done with the inclusion of model performance criteria which eliminated poorly performing days (i.e., error > 35%). The results show good agreement in the modeled and monitored ozone concentration changes (e.g., ozone improves by about 9-10 ppb between 2002 and 2005 according to the model and the measurements) – see Figure 54. This provides further support for using the model to develop ozone control strategies.



	MP Criteria	No MP Cr.
Obs_abs_delta	-8.4	-8.8
Pred_abs_delta	-6.2	-4.6
Obs_pct_delta	-10.5	-10.9
Pred_pct_delta	-8.7	-6.7
r	0.64	0.51
r^2	0.41	0.26

Figure 54. Comparison of change in predicted and observed ozone concentrations (2002 v. 2005)

$PM_{2.5}$: Time series plots of the monthly average mean bias and annual fractional bias for Base M and Base K are shown in Figure 55. As can be seen, Base M model performance for most species is fair (i.e., close to "no bias" throughout most of the year), with two main exceptions. First, the Base M and Base K results for organic carbon are poor, suggesting the need for more work on primary organic carbon emissions. Second, the Base M results for sulfate, while acceptable (i.e., bias values are within 35%), are not as good as the Base K results (e.g., noticeable underprediction during the summer months).

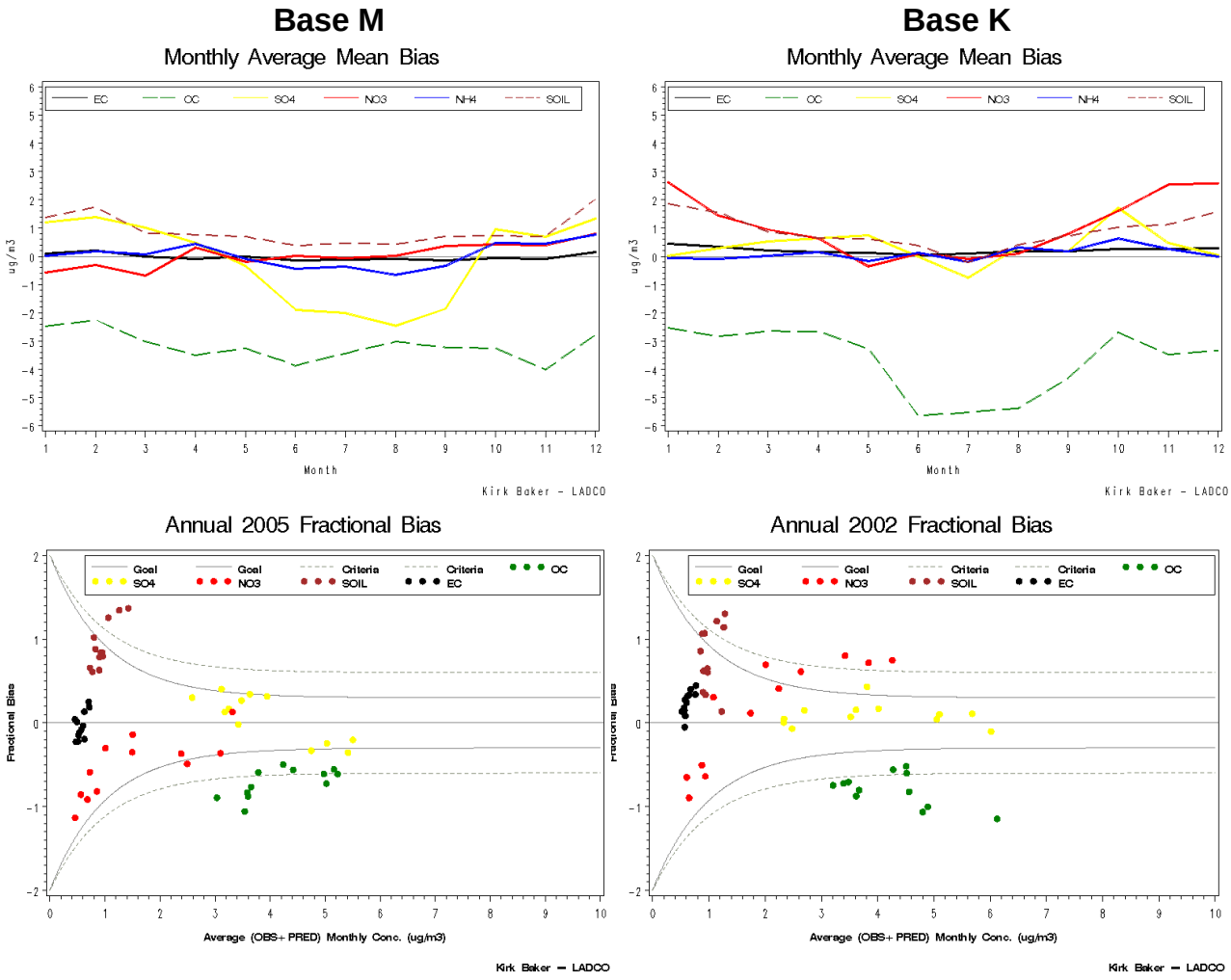


Figure 55. $PM_{2.5}$ Model performance - monthly average mean bias and annual fractional bias for Base M (left column) and Base K (right column)

Two analyses were undertaken to understand sulfate model performance for 2005:

- Assess Meteorological Influences: The MM5 model performance evaluation showed that rainfall is over-predicted by MM5 over most of the domain during the summer months (LADCO, 2007c). Because CAMx does not explicitly use the rainfall output by MM5, this may or may not result in over-prediction sulfate wet deposition (and under-prediction of sulfate concentrations). A sensitivity run was performed with no wet deposition for July, August, and September. The resulting model performance (see green line in Figure 56) showed a noticeable difference from the basecase (i.e., higher sulfate concentrations), and suggests that further evaluation of MM5 precipitation fields may be warranted.

- Assess Emissions Influences: The major contributor to sulfate concentrations in the region is SO2 emitted from EGUs. The basecase modeling inventory for EGUs is based on annual emissions, which were allocated to a typical weekday, Saturday, and Sunday by month using CEM-based temporal profiles. A sensitivity run was performed using day-specific emissions. The resulting model performance (see purple line in Figure 56) showed little difference from the basecase.

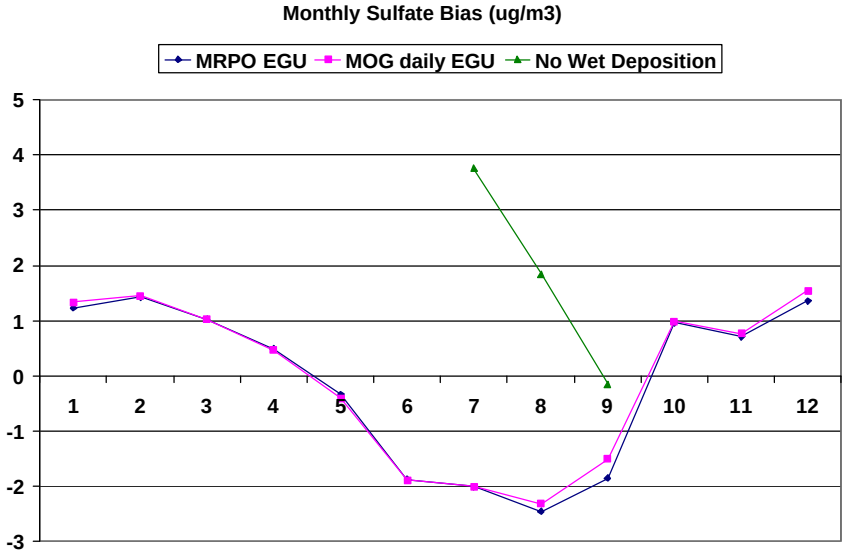


Figure 56. Monthly sulfate bias for Base M (MRPO EGU) v. two sensitivity analyses (Note: positive values indicate over-prediction, negative values indicate under-prediction)

To assess the effect of the wet deposition issue on future year modeled values, another sensitivity run was conducted with no wet deposition in Quarters 2-3 for the base year (2005) and 2018. The resulting future year values were only slightly different from the current base strategy run. In general, the future year values (without wet deposition) were a little higher (+0.15 ug/m^3 or less) in the Ohio Valley and a little lower (-.10 ug/m^3 of less) in the Great Lakes region. This sensitivity run provides a bound for sulfate wet deposition issue in terms of the attainment test, given that having no wet deposition is unrealistic. The results suggest that even with an improved wet deposition treatment, the Base M strategy results are not expected to change very much.

Time series plots of daily sulfate, nitrate, elemental carbon, and organic carbon concentrations for three Midwestern locations are presented in Figures 57 (2002) and 58 (2005). These results are consistent with the model performance statistics (i.e., good agreement for sulfates and nitrates and poor agreement [large underprediction] for organic carbon).

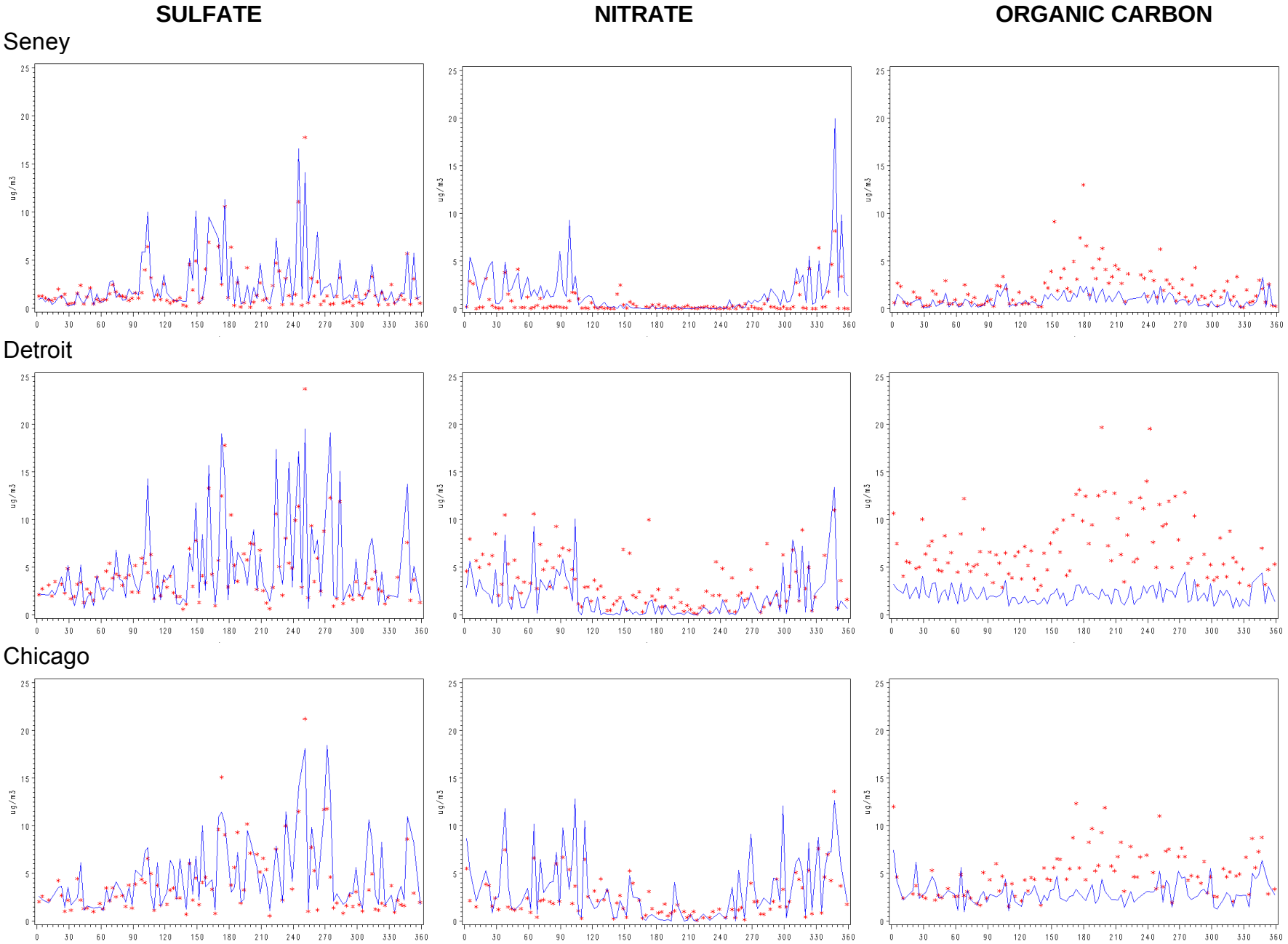
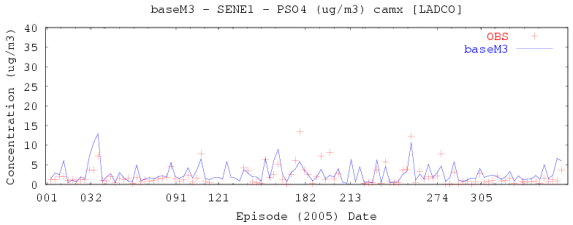
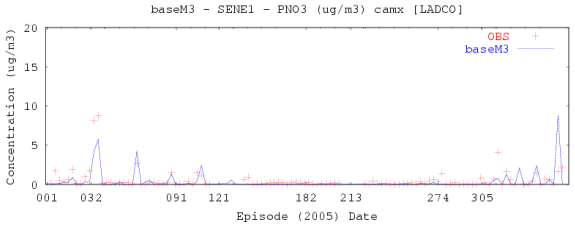


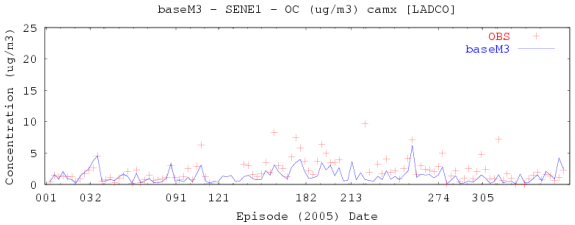
Figure 57. Time series of sulfate, nitrate, and organic carbon at three Midwest sites for 2005

SULFATE	NITRATE	ORGANIC CARBON

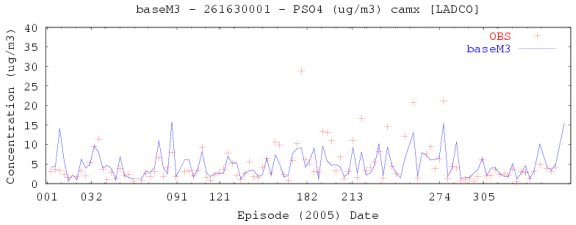
Seney

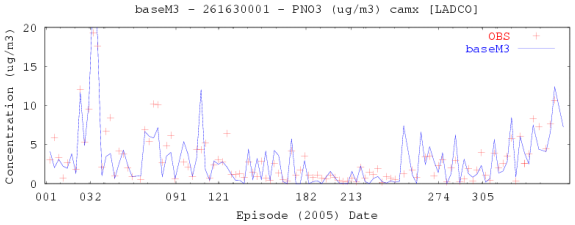


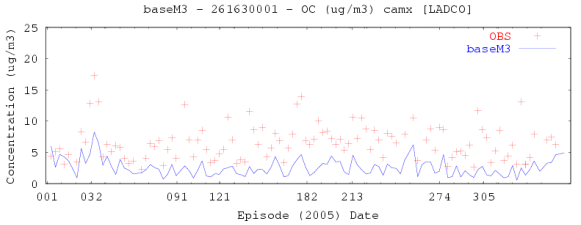




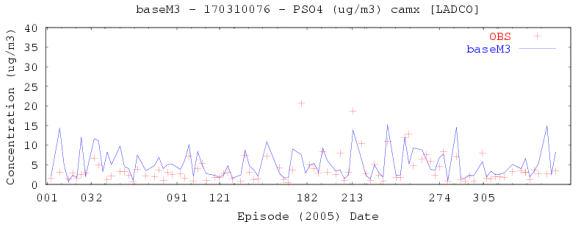
Detroit

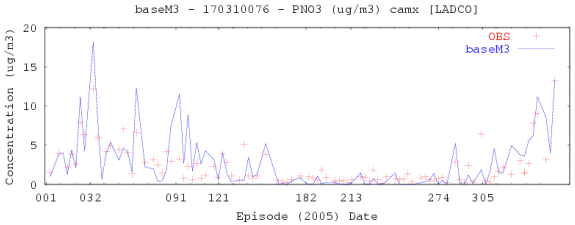






Chicago





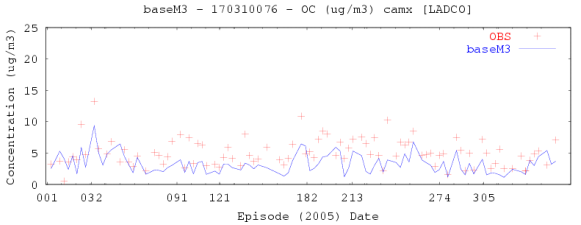


Figure 58. Time series of sulfate, nitrate, and organic carbon at three Midwest sites for 2005

In summary, model performance for ozone and $PM_{2.5}$ is generally acceptable and can be characterized as follows:

Ozone

- Good agreement between modeled and monitored concentration for higher concentration levels (> 60 ppb) – i.e., bias within 30%

- Regional modeled concentrations appear to be underestimated in the 2002 base year, but show better agreement (with monitored data) in the 2005 base year due to model and inventory improvements.

- Day-to-day and hour-to-hour variation in and spatial patterns of modeled concentrations are consistent with monitored data

- Model accurately simulates the change in monitored ozone concentrations due to reductions in precursor emissions.

$PM_{2.5}$

- Good agreement in the magnitude of fine particle mass, but some species are overestimated and some are underestimated (during periods of the year when it is important)
    - Sulfates: good agreement in the 2002 base year, but underestimated in the summer in the 2005 base year due probably to meteorological factors
    - Nitrates: slightly overestimated in the winter in the 2002 base year, but good agreement in the 2005 base year as a result of model and inventory improvements
    - Organic Carbon: grossly underestimated in the 2002 and 2005 base years due likely to missing primary organic carbon emissions and, possibly, other factors (e.g., grid resolution and model chemistry).

- Temporal variation and spatial patterns of modeled concentrations are consistent with monitored data

Several observations should be noted on the implications of these model performance findings on the attainment modeling presented in the following section. First, it has been demonstrated that model performance overall is acceptable and, thus, the model can be used for air quality planning purposes. Second, consistent with EPA guidance, the model is used in a relative sense to project future year values. EPA suggests that this approach "should reduce some of the uncertainty attendant with using absolute model predictions alone" (EPA, 2007a). Furthermore, the attainment modeling is supplemented by additional information to provide a weight of evidence determination.

Section 4.0 Attainment Demonstration for Ozone and $PM_{2./5}$

Air quality modeling and other information were used to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the NAAQS for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Traditionally, attainment demonstrations involved a "bright line" test in which a single modeled value was compared to the ambient standard. To provide a more robust assessment of expected future year air quality, EPA's modeling guidelines call for consideration of supplemental information. This section summarizes the results of the primary (guideline) modeling analysis and a weight of evidence determination based on the modeling results and other supplemental analyses.

4.1 Future Year Modeling Results

The purpose of the future year modeling is to assess the effectiveness of existing and possible additional control programs. The model was used in a relative sense to project future year values, which are then compared to the standard to determine attainment/nonattainment. Specifically, the modeling test consists of the following steps:

(1) Calculate base year design values: For ozone and $PM_{2.5}$, the base year design values were derived by averaging the three 3-year periods centered on the emissions base year:

2002 base year: 2000-2002, 2001-2003, and 2002-2004
2005 base year: 2003-2005, 2004-2006, and 2005-2007[11]

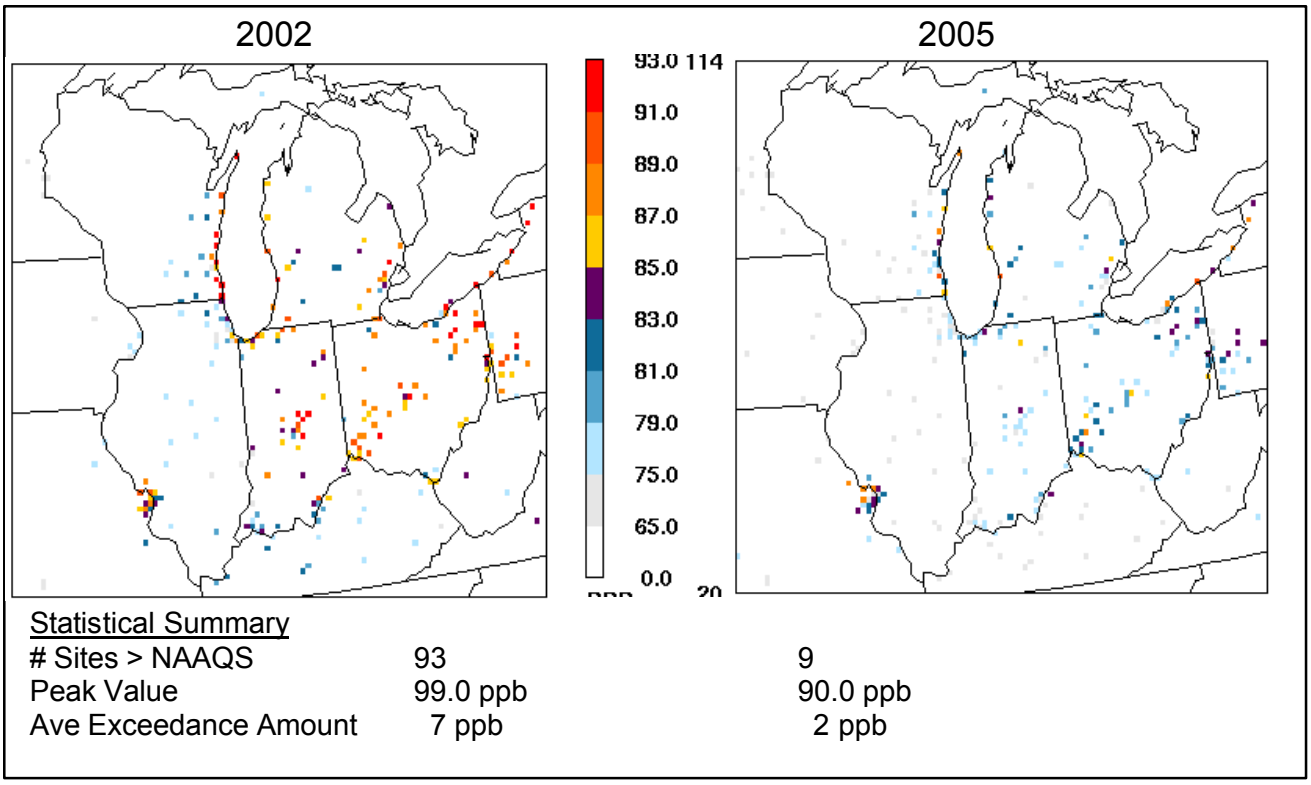
(2) Estimate the expected change in air quality: For each grid cell, a relative reduction factor (RRF) is calculated by taking the ratio of the future year and baseline modeling results.

(3) Calculate future year values: For each grid cell (with a monitor), the RRFs are multiplied by the base year design values to project the future year values

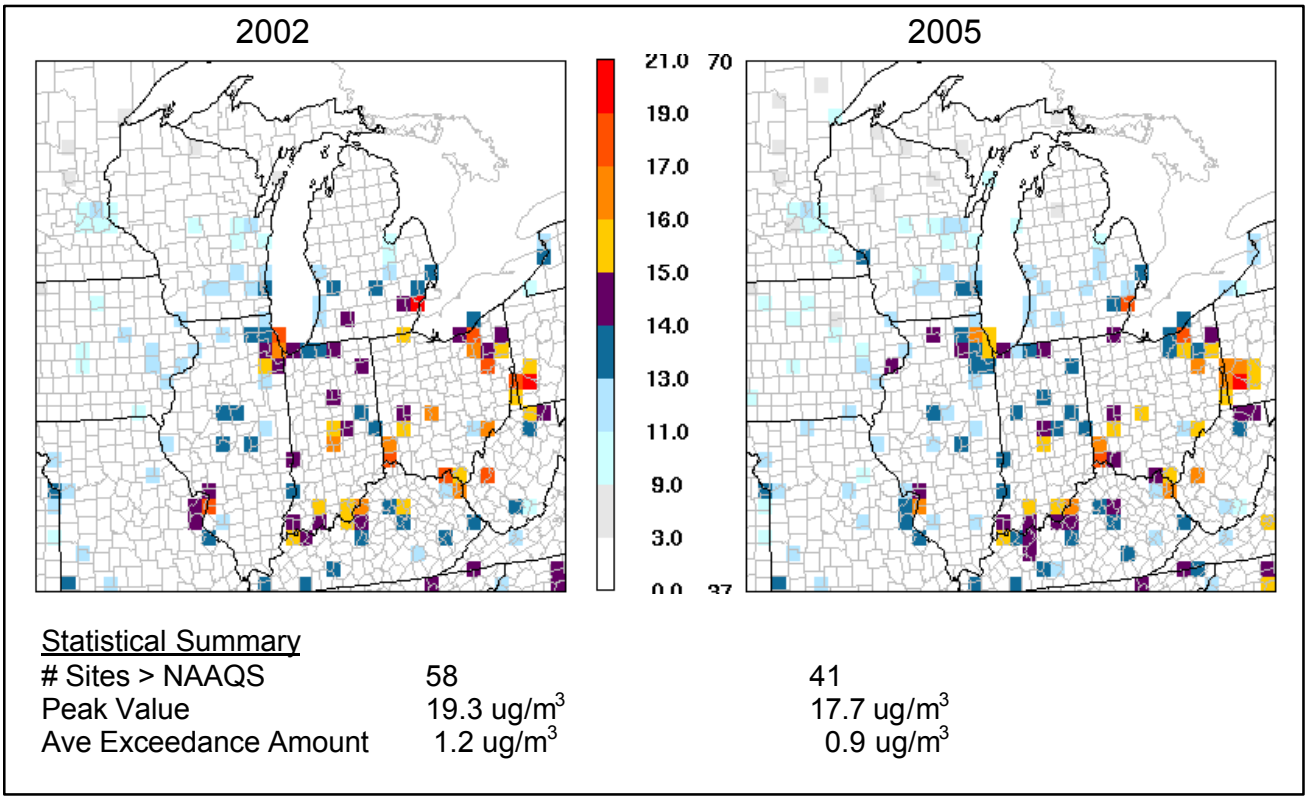
(4) Assess attainment: Future year values are compared to the NAAQS to assess attainment or nonattainment.

A comparison of the 2002 and 2005 base year design values for ozone and $PM_{2.5}$ is provided in Figure 59. In general, the figure shows that the 2005 base year design values are much lower than the 2002 base year design values, especially for ozone.

[11] A handful of source-oriented PM2.5 monitors in Illinois and Indiana were excluded from the annual attainment test, because these monitors are not to be used to judging attainment of the annual standard.



Statistical Summary		
# Sites > NAAQS	93	9
Peak Value	99.0 ppb	90.0 ppb
Ave Exceedance Amount	7 ppb	2 ppb



Statistical Summary		
# Sites > NAAQS	58	41
Peak Value	19.3 ug/m^3	17.7 ug/m^3
Ave Exceedance Amount	1.2 ug/m^3	0.9 ug/m^3

Figure 59. 2002 v. 2005 base year design values for ozone (top) and $PM_{2.5}$ (bottom)

Ozone results are provided for those grid cells with ozone monitors. The RRF calculation considers all nearby grid cells (i.e., 3x3 for 12 km modeling) and a threshold of 85 ppb. (If there were less than 10 days above this value, then the threshold was lowered until either there were 10 days or the threshold reached 70 ppb.) $PM_{2.5}$ results are provided for those grid cells with FRM ($PM_{2.5}$-mass) monitors. Spatial mapping was performed to extrapolate $PM_{2.5}$-speciation data from STN and IMPROVE sites to FRM sites. RRF values for $PM_{2.5}$ were derived as a function of quarter and chemical species.

Additional, hot-spot modeling will be performed by the states for certain $PM_{2.5}$ nonattainment areas (e.g., Detroit, Cleveland, and Granite City) to address primary emissions from local point sources which may not be adequately accounted for by the regional grid modeling. This modeling will consist of Gaussian dispersion modeling (e.g., AERMOD) performed in accordance with EPA's modeling guidance (see Section 5.3 of the April 2007 guidance document). Further analyses will need to be undertaken to determine how to best combine the regional modeling and the hot-spot modeling. This could mean some adjustment to the model results presented in this document to reflect better the regional component.

The ozone and $PM_{2.5}$ modeling results are provided in Appendix I for select monitors (high concentration sites) in the 5-state region for the following future years of interest: 2008 (ozone only), 2009, 2012, and 2018. (Note, RRF values for ozone, and for $PM_{2.5}$ by season and chemical species are also included in Appendix I for key monitoring sites.) A summary of the modeling results is provided in Table 9 (ozone) and Table 10 ($PM_{2.5}$), and spatial maps of the Base M future year concentrations are provided in Figures 60-62.

Table 9. Summary of Ozone Modeling Results									
Key Sites		**2008**		**2009**		**2012**		**2018**
		Round 5	Round 4	Round 5	Round 4	Round 5	Round 4	Round 5
Lake Michigan Area								
Chiwaukee	550590019	82.0	**93.0**	82.3	**92.0**	80.9	**90.3**	76.2
Racine	551010017	77.6	**85.9**	77.5	84.9	76.1	82.9	71.2
Milwaukee-Bayside	550190085	79.6	**85.4**	79.8	84.9	78.0	82.3	72.7
Harrington Beach	550890009	80.0	**86.7**	80.1	**85.4**	78.3	82.9	72.5
Manitowoc	550710007	81.3	80.3	80.8	78.9	78.6	76.3	72.5
Sheboygan	551170006	84.4	**90.0**	84.0	**88.9**	81.8	**86.4**	75.4
Kewaunee	550610002	78.9	82.5	78.1	81.0	75.9	79.1	69.9
Door County	550290004	84.8	83.6	83.9	81.8	81.5	79.3	74.7
Hammond	180892008	75.4	**86.9**	75.4	**86.6**	74.6	**86.3**	71.6
Whiting	180890030	77.0		77.0		76.2		73.1
Michigan City	180910005	74.2	**87.4**	73.9	**86.5**	72.5	**85.4**	68.1
Ogden Dunes	181270020	75.7	82.3	75.6	82.8	74.5	82.0	70.8
Holland	260050003	**85.6**	84.9	**85.3**	83.4	82.8	81.0	76.1
Jenison	261390005	77.9	78.7	77.1	77.6	74.5	75.5	68.7
Muskegon	261210039	80.8	82.7	80.5	81.5	78.0	79.4	71.9
Indianapolis Area								
Noblesville	189571001	78.0	**85.2**	78.1	83.7	75.6	82.0	68.7
Fortville	180590003	73.9	**85.1**	73.9	83.8	71.4	82.1	65.1
Fort B. Harrison	180970050	74.8	84.8	75.1	83.7	73.2	82.4	69.1
Detroit Area								
New Haven	260990009	82.7	**86.3**	81.4	**85.3**	80.2	83.5	76.1
Warren	260991003	82.5	84.3	81.3	83.3	80.7	81.9	77.6
Port Huron	261470005	79.0	80.5	77.5	79.1	75.5	77.0	70.9
Cleveland Area								
Ashtabula	390071001	84.9	84.7	83.4	82.7	81.0	80.2	75.1
Geauga	390550004	75.7	**90.3**	74.7	**88.8**	72.7	**86.2**	67.3
Eastlake	390850003	82.8	84.2	81.9	82.8	80.5	80.6	76.2
Akron	391530020	79.3	83.0	78.1	81.4	75.6	78.5	68.7
Cincinnati Area								
Wilmington	390271002	77.8	84.8	77.5	83.5	74.9	81.1	68.3
Sycamore	390610006	81.7	**85.4**	81.9	84.7	80.3	82.9	74.6
Lebanon	391650007	83.6	80.1	83.0	79.0	80.7	77.0	74.2
Columbus Area								
London	390970007	75.4	79.9	75.0	78.4	72.6	76.5	66.3
New Albany	390490029	82.4	84.1	81.8	82.6	79.6	80.2	73.0
Franklin	290490028	77.0	77.7	75.9	76.5	74.1	74.7	69.0
St. Louis Area								
W. Alton (MO)	291831002	82.4	**86.1**	81.0	**85.2**	78.6	84.0	74.9
Orchard (MO)	291831004	83.3	83.3	82.0	82.2	80.0	80.4	76.2
Sunset Hills (MO)	291890004	79.5	82.8	78.7	81.9	77.1	80.6	73.9
Arnold (MO)	290990012	78.7	78.4	77.2	77.4	75.6	75.8	72.0
Margaretta (MO)	295100086	79.8	84.0	79.3	83.4	77.9	82.5	74.4
Maryland Heights (MO)	291890014	84.5		83.4		81.7		78.1

Table 10. Summary of PM2.5 Modeling Results								
			2009		2012		2018	
County	**Site ID**	**Site**	**Round 5**	**Round4**	**Round 5**	**Round4**	**Round 5**	**Round4**
Cook	170310022	Chicago - Washington HS	14.1	14.8	14.0	14.6	13.9	14.4
Cook	170310052	Chicago - Mayfair	14.4	**15.8**	14.2	**15.5**	13.9	**15.0**
Cook	170310057	Chicago - Springfield	13.9	14.5	13.8	14.3	13.7	14.1
Cook	170310076	Chicago - Lawndale	13.8	14.5	13.7	14.3	13.6	14.1
Cook	170312001	Blue Island	13.7	14.5	13.6	14.3	13.4	14.1
Cook	170313301	Summit	14.2	14.8	14.0	14.6	13.9	14.4
Cook	170316005	Cicero	14.4	**15.3**	14.3	**15.1**	14.2	14.9
Madison	171191007	Granite City	**15.1**	**16.0**	14.9	**15.8**	14.3	**15.5**
St. Clair	171630010	E. St. Louis	14.1	14.9	13.9	14.7	13.4	14.5
Clark	180190005	Jeffersonville	13.8	**15.5**	13.7	**15.0**	13.4	14.4
Dubois	180372001	Jasper	12.4	13.8	12.2	13.5	11.8	13.0
Lake	180890031	Gary	13.0		12.8		12.4	
Marion	180970078	Indy-Washington Park	12.8	14.5	12.6	14.2	12.0	13.7
Marion	180970083	Indy- Michigan Street	13.4	14.8	13.1	14.9	12.6	14.0
Wayne	261630001	Allen Park	13.0	14.5	12.8	14.1	12.4	13.3
Wayne	261630015	Southwest HS	14.2	**15.8**	13.9	**15.3**	13.5	14.4
Wayne	261630016	Linwood	13.1	14.1	12.8	13.7	12.5	13.0
Wayne	261630033	Dearborn	**15.8**	**17.7**	**15.5**	**17.1**	**15.1**	**16.1**
Wayne	261630036	Wyandotte	13.1	**15.1**	12.8	14.7	12.5	13.9
Butler	390170003	Middleton	13.5	14.2	13.2	13.7	12.8	13.1
Butler	390170016	Fairfield	13.1	13.5	12.9	12.9	12.5	12.2
Cuyahoga	390350027	Cleveland-28th Street	13.5	14.4	13.2	13.8	12.7	12.9
Cuyahoga	390350038	Cleveland-St. Tikhon	**15.2**	**16.1**	14.8	**15.4**	14.3	14.4
Cuyahoga	390350045	Cleveland-Broadway	14.4	14.6	14.0	14.0	13.5	13.1
Cuyahoga	390350060	Cleveland-GT Craig	15.0	**15.3**	14.6	14.7	14.1	13.7
Cuyahoga	390350065	Newburg Hts - Harvard Ave	14.0	14.1	13.6	13.5	13.1	12.6
Franklin	390490024	Columbus - Fairgrounds	12.9	14.6	12.6	14.0	12.0	13.0
Franklin	390490025	Columbus - Ann Street	12.7	14.1	12.4	13.5	11.9	12.5
Franklin	390490081	Columbus - Maple Canyon	11.7	14.0	11.4	13.4	10.9	12.5
Hamilton	390610014	Cincinnati - Seymour	14.5	**15.5**	14.3	14.8	13.8	14.0
Hamilton	390610040	Cincinnati - Taft Ave	12.8	13.6	12.6	13.0	12.2	12.3
Hamilton	390610042	Cincinnati - 8th Ave	14.0	14.6	13.8	14.0	13.4	13.2
Hamilton	390610043	Sharonville	12.9	13.6	12.7	13.0	12.3	12.2
Hamilton	390617001	Norwood	13.4	14.2	13.2	13.6	12.8	12.8
Hamilton	390618001	St. Bernard	14.7	**15.2**	14.4	14.6	14.0	13.8
Jefferson	390810016	Steubenville	12.8	**16.3**	12.5	**15.9**	12.7	**16.2**
Jefferson	390811001	Mingo Junction	13.5	**15.5**	13.2	**15.0**	13.4	**15.3**
Lawrence	390870010	Ironton	12.8	14.2	12.5	13.7	12.3	13.2
Montgomery	391130032	Dayton	13.2	13.7	12.9	13.2	12.4	12.3
Scioto	391450013	New Boston	12.1	**15.4**	11.9	14.8	11.6	14.2
Stark	391510017	Canton - Dueber	14.0	**15.0**	13.6	14.3	13.3	13.6
Stark	391510020	Canton - Market	12.6	13.6	12.3	13.0	11.9	12.2
Summit	391530017	Akron - Brittain	13.0	14.4	12.7	13.6	12.3	12.9
Summit	391530023	Akron - W. Exchange	12.3	13.6	12.0	13.0	11.5	12.2

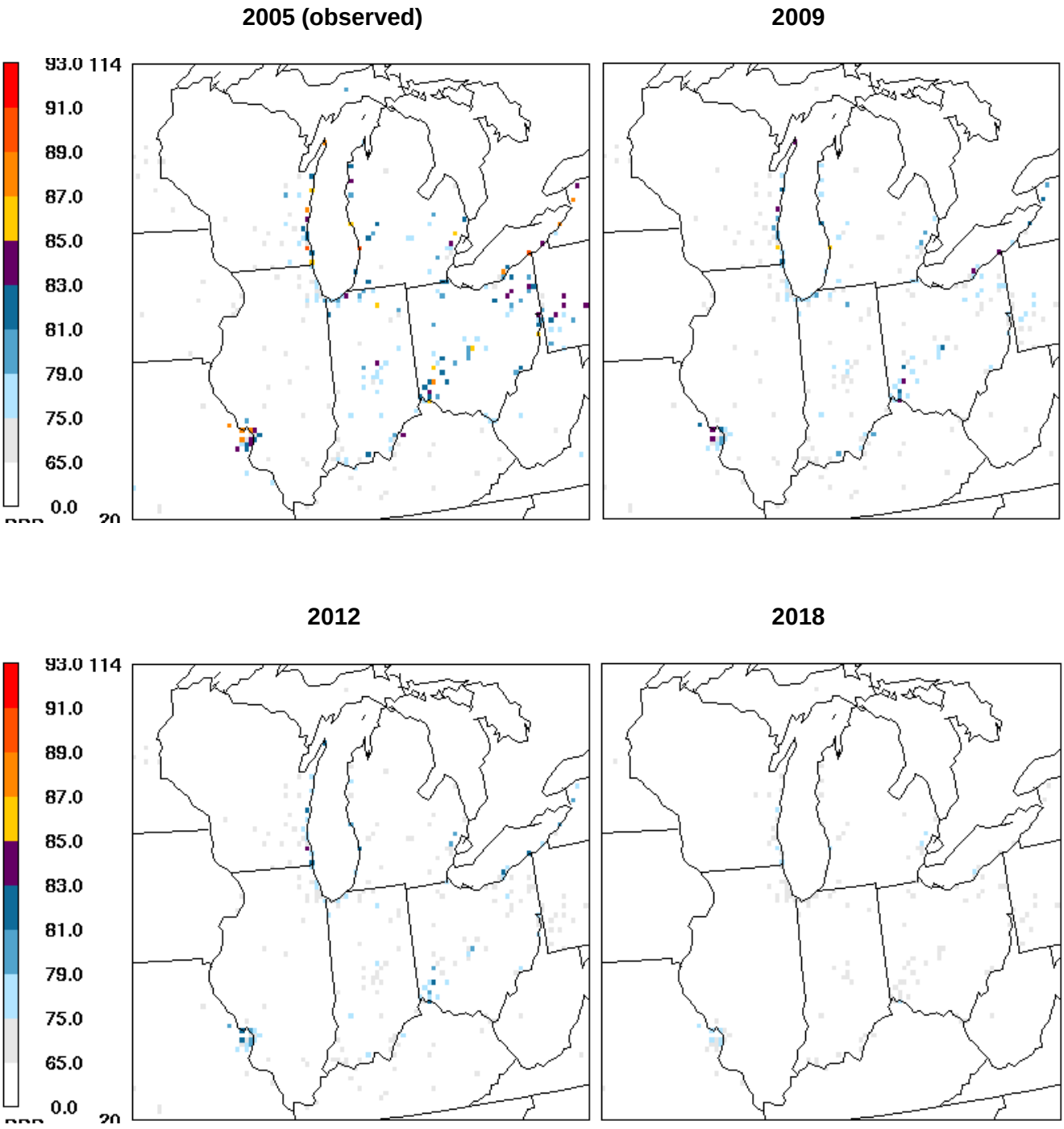


Figure 60. Observed base year and projected future year design values for ozone – Base M

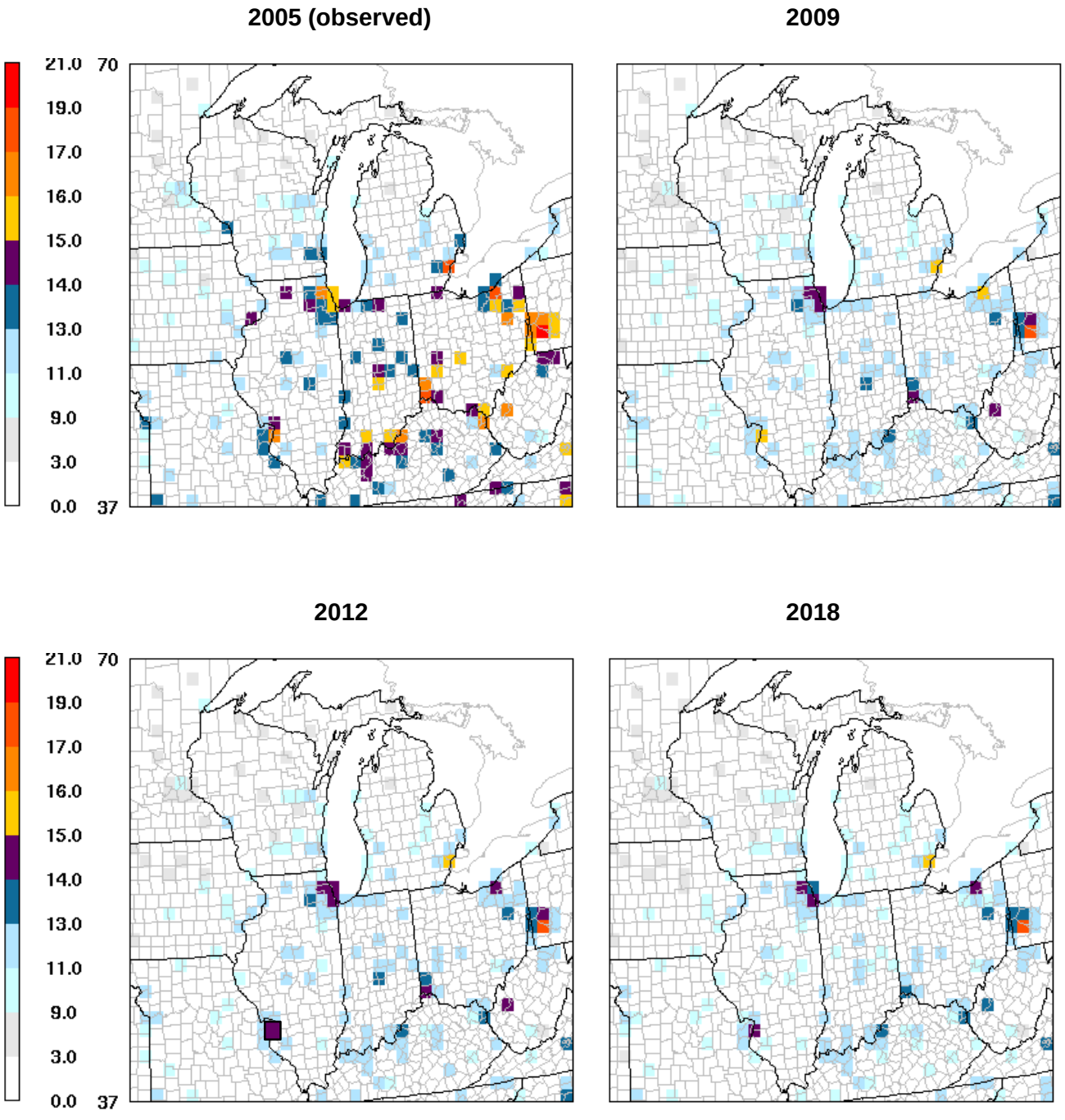


Figure 61. Observed base year and projected future year design values for $PM_{2.5}$ (annual average)–Base M

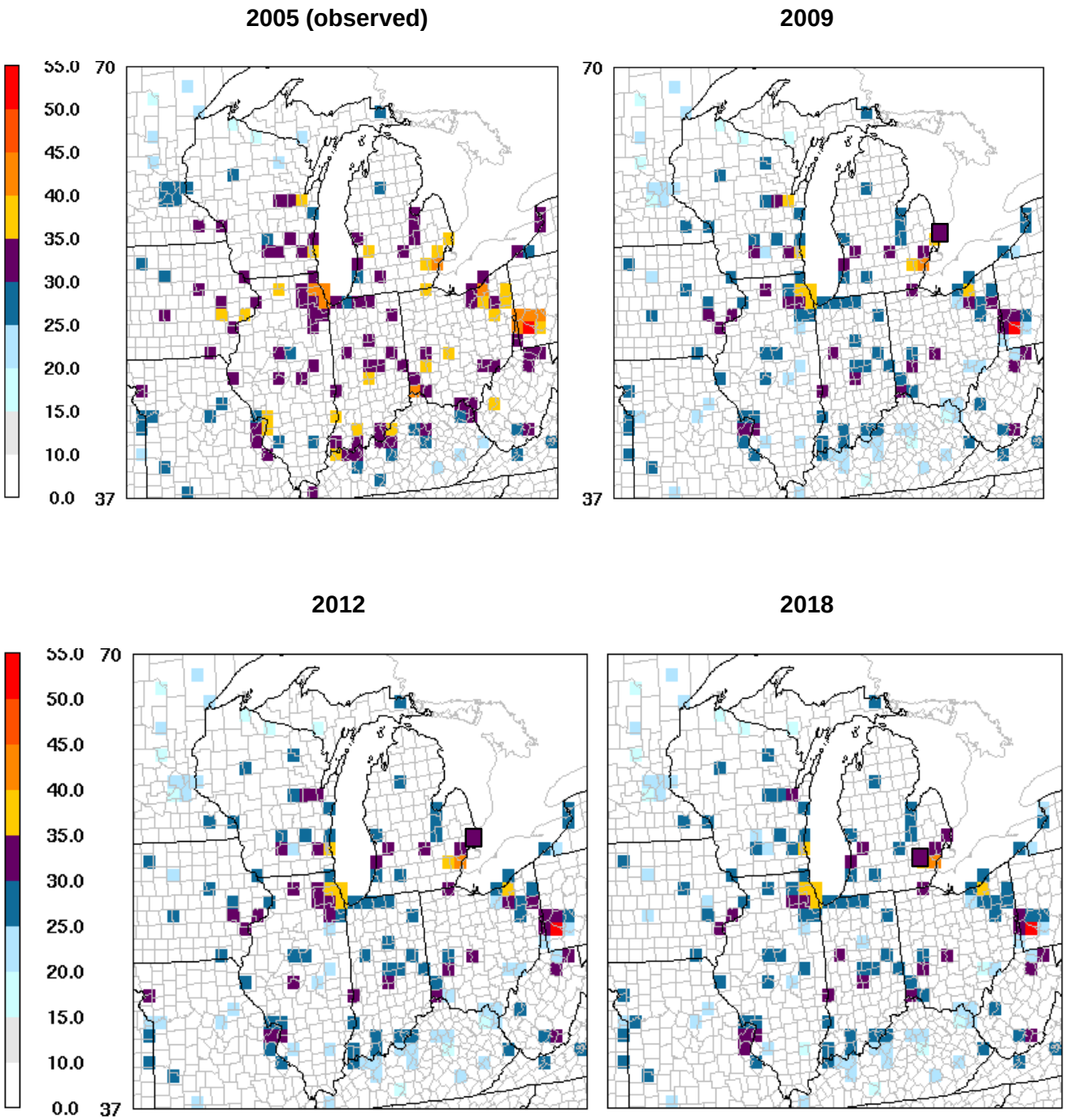


Figure 62. Observed base year and projected future year design values for $PM_{2.5}$ (24-hr average)-Base M

The number of monitors with design values above the standard are as follows:

Table 11. Number of sites above standard

Ozone (8 hour: 85 ppb)										
State	2002	2005		2009			2012			2018	
	BaseK	Base M		BaseK	Base M		BaseK	Base M		BaseK	Base M
IL	3	0		0	0		0	0		0	0
IN	22	0		0	0		0	0		0	0
MI	15	3		1	1		0	0		0	0
OH	40	4		1	0		1	0		0	0
WI	13	2		4	0		3	0		1	0
Total	93	9		6	1		4	0		1	0
PM2.5 (Annual: 15 ug/m^3)										
State	2002	2005		2009			2012			2018	
	BaseK	Base M		BaseK	Base M		BaseK	Base M		BaseK	Base M
IL	11	7		3	1		3	0		2	0
IN	10	6		1	0		1	0		0	0
MI	6	2		3	1		2	1		0	0
OH	31	26		7	1		4	0		1	1
WI	0	0		0	0		0	0		2	0
Total	58	41		14	3		10	1		5	1

The modeling results above reflect the "base" controls identified in Section 3.6, with EGU emissions based on IPM modeling (i.e., Round 4 – IPM2.1.9, and Round 5 – IPM3.0). In addition, two sets of alternative future year EGU emissions were examined in Round 5. First, alternative control assumptions were provided for several facilities by the states (i.e., "will do" and "may do" scenarios). In general, these scenarios produced a small change in future year ozone and $PM_{2.5}$ concentrations (i.e., about 0.1 ug/m^3 for $PM_{2.5}$ and 0.1-0.2 ppb for ozone). Second, EPA suggested adjustments to the 2010 IPM emissions to reflect 2009 conditions. The revised (2009) SO2 emissions represent a 5-6% increase in domainwide SO2 emissions. The increased SO2 emissions result in slightly greater annual average $PM_{2.5}$ concentrations (on the order of 0.1 – 0.2 ug/m^3), but do not produce any new residual nonattainment areas.

The limited 4 km ozone modeling (based on Base K) performed by LADCO included a future year analysis for 2009. The figure below shows the 2009 values with 12 km and 4 km grid spacing for the LADCO modeling and similar modeling conducted by a stakeholder group (Midwest Ozone Group).

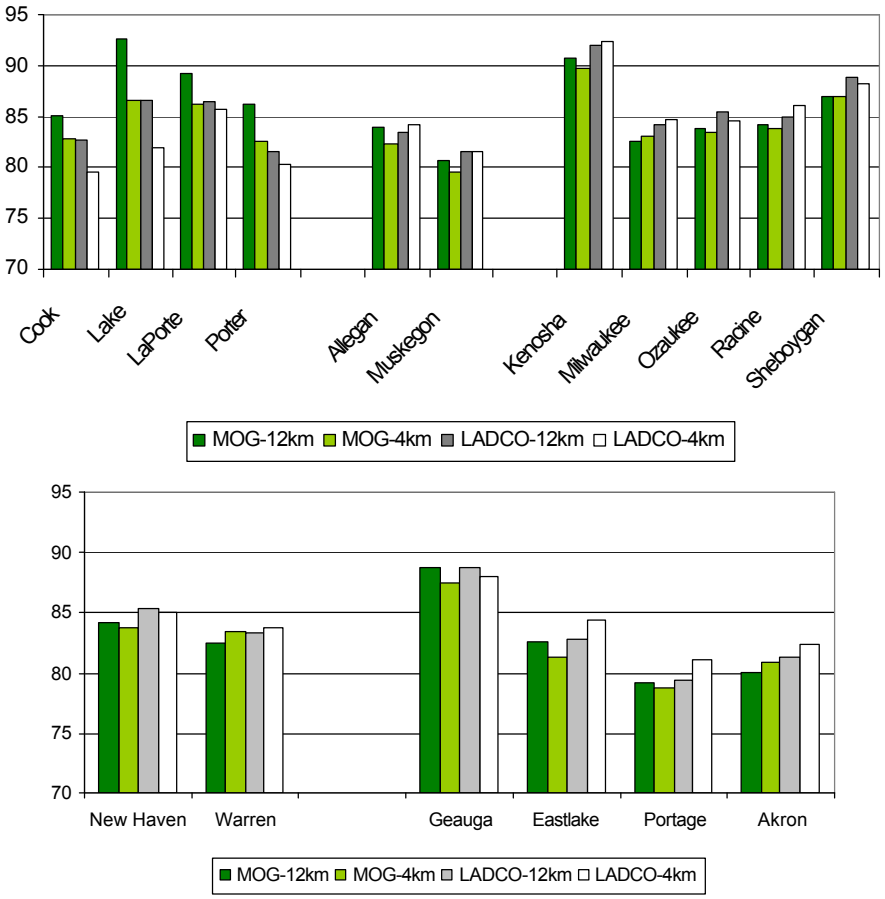


Figure 63. Future year (2009) values for Lake Michigan area (top) and Detroit-Cleveland region (bottom)

These results show that the 12 km and 4 km values are similar, with the most notable changes in northwestern Indiana and northeastern Illinois (e.g., 4 km values are as much as 4 ppb lower than 12 km values). The differences in the southern part of the Lake Michigan area are plausible, given the tight emissions gradient there (i.e., finer grid resolution appears to provide more appropriate representation).

In light of these findings, 12 km grid spacing can continue to be used for ozone modeling, but the Base K/Round 4 results for northwestern Indiana/northeastern Illinois should be viewed with caution (i.e., probably 1 – 4 ppb too high).

In summary, the ozone modeling provides the following information for the nonattainment areas in the region (see Table 12):

Table 12. Ozone Nonattainment Areas in the LADCO Region (as of December 31, 2007)

Area Name	Category	Number of Counties	Attainment Deadline
Detroit-Ann Arbor, MI	Marginal	8	2007
Chicago-Gary-Lake County, IL-IN	Moderate	10	2010
Cleveland-Akron-Lorain, OH	Moderate	8	2010
Milwaukee-Racine, WI	Moderate	6	2010
Sheboygan, WI	Moderate	1	2010
St Louis, MO-IL	Moderate	4	2010
Allegan Co, MI	Subpart 1	1	2009
Cincinnati-Hamilton, OH-KY-IN	Subpart 1	6	2009
Columbus, OH	Subpart 1	6	2009
Door Co, WI	Subpart 1	1	2009
Kewaunee Co, WI	Subpart 1	1	2009
Manitowoc Co, WI	Subpart 1	1	2009
		53	

Marginal Areas (2007 attainment date): No modeling was conducted for the 2006 SIP planning year. Rather, 2005 – 2007 air quality data are available to determine attainment.

Basic (Subpart 1) Areas (2009 attainment date): The modeling results for the 2008 SIP planning year show:

- Base K: all areas in attainment, except Cincinnati and Indianapolis
- Base M: all areas in attainment, except Holland (Allegan County)

Moderate Areas (2010 attainment date): The modeling results for the 2009 SIP planning year show:

- Base K: all areas still in nonattainment
- Base M: all areas in attainment

The $PM_{2.5}$ modeling results show:

- Base K: all areas in attainment, except for Chicago, Cincinnati, Cleveland, Detroit, Granite City (IL), Louisville, Portsmouth (OH), and Steubenville
- Base M: all areas in attainment, except for Cleveland, Detroit, and Granite City (IL)

With respect to the new lower 8-hour ozone standard, the modeling about 30 sites in 2012 and 5 sites in 2018 with design values greater than 75 ppb. With respect to the new lower 24-hour $PM_{2.5}$ standard, the modeling shows 13 sites in 2012 and 10 in 2018 with design values greater than 35 ug/m^3.

4.2 Supplemental Analyses

EPA's modeling guidelines recommend that attainment demonstrations consist of a primary (guideline) modeling analysis and supplemental analyses. Three basic types of supplemental analyses are recommended:

- additional modeling
- analyses of trends in ambient air quality and emissions, and
- observational models and diagnostic analyses

Furthermore, according to EPA's guidelines, if the future year modeled values are "close" to the standard (i.e., 82 – 87 ppb for ozone and 14.5 – 15.5 ug/m^3 for $PM_{2.5}$), then the results of the primary modeling should be reviewed along with the supplemental information in a "weight of evidence" assessment of whether each area is likely to achieve timely attainment.

A WOE determination for ozone and $PM_{2.5}$ is provided in the following sections. Special attention is given to the following areas with future year modeled values that exceed or are "close" to the ambient standard (see Appendix I):

Ozone	**PM2.5**
Lake Michigan area	Chicago, IL
Cleveland, OH	Cleveland, OH
Cincinnati, OH	Cincinnati, OH
	Granite City, IL
	Detroit, MI

4.3 Weight-of-Evidence Determination for Ozone

The WOE determination for ozone consists of the primary modeling and other supplemental analyses (some of which were discussed in Section 2). A summary of this information is provided below.

Primary (Guideline) Modeling: The guideline modeling is presented in Section 4.1. Key findings from this modeling include:

- Base M regional modeling shows attainment by 2008 and 2009 at all sites, except Holland (MI), and attainment at all sites by 2012.

- Base K modeling results reflect generally higher future year values, and show more sites in nonattainment compared to the Base M modeling. The difference in the two modeling analyses is due mostly to lower base year design values in Base M.

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for ozone should reflect a weight-of-evidence approach, with consideration of monitoring based information.

- Base M modeling also shows that the proposed lower 8-hour standard will not be met at many sites, even by 2018, with existing controls.

Additional Modeling: Four additional modeling analyses were considered: (1) re-examination of the primary modeling to estimate attainment probabilities, (2) remodeling with different assumptions, (3) an unmonitored area analysis, and (4) EPA's latest regional ozone modeling. Each of these analyses is described below.

First, the primary modeling results (which were initially processed using EPA's attainment test) were re-examined to estimate the probability of attaining the ozone standard (Lopez, 2007, and LADCO, 2008b). Seven estimates of future year ozone concentrations were calculated based on model-based RRFs and appropriate monitor-based concentrations for each year between 2001 and 2007. RRF values for 2001, 2003, 2004, 2006, and 2007 were derived based on the 2002 and 2005 modeling results. Monitor-based concentrations reflect 4th high values, design values, or average of three design values centered on the year in question. The probability of attainment was determined as the percentage of these seven estimates below the standard. The results indicate that sites in the Lake Michigan area (Chiwaukee, Sheboygan, Holland, Muskegon), Cleveland (Ashtabula), and St. Louis (W Alton) have a fairly low probability of attainment by 2009 (i.e., about 50% or less).

Second, the primary modeling analysis was redone with different types of assumptions for calculating base year design values (i.e., using the 3-year period centered on base year, and using the highest 3-year period that includes the base year), and for calculating RRFs (i.e., using all days with base year modeled value > 70 ppb, and using all days with base year modeled value > 85 ppb, with at least 10 days and "acceptable" model performance). The results for several high concentration sites are presented in Tables 13a and 13b for 2009. The different modeling assumptions produce eight estimates of future year ozone concentrations. The highest estimates are associated with base year design values representing the 3-year average for 2001-2003, and the lowest estimates are associated with base year design values representing the 3-year average 2004-2006. The different RRF approaches produce little change in future year ozone concentrations. This suggests that future year concentration estimates are most sensitive to the choice of the base year and the methodology used to derive the base year design values.

Third, EPA's modeling guidelines recommend that an "unmonitored area analysis" be included as a supplemental analysis, particularly in nonattainment areas where the monitoring network just meets or minimally exceeds the size of the network required to report data to EPA's Air Quality System. The purpose of this analysis is to identify areas where future year values are predicted to be greater than the NAAQS.

Based on examination of the spatial plots in Figures 49a and 49b, the most notable areas of high modeled ozone concentrations are over the Great Lakes. Over-water monitoring, however, is not required by EPA[12]. A cursory analysis of unmonitored areas for ozone was performed by LADCO using an earlier version of the 2002 base year modeling (i.e, Base I) (Baker, 2005). Base year and future year "observed" values were derived for unmonitored grid cells using the absolute modeled concentrations (in all grid cells) and the observed values (in monitored grid cells). A spatial map of the estimated 2009 values is provided in Figure 64. As can be seen, there are very few (over land) grid cells where additional monitors may be desirable. This indicates that the current modeling analysis, which focuses on monitored locations, is addressing areas of high ozone throughout the region.

[12] Air quality measurements over Lake Michigan were collected by LADCO previously to understand ozone transport in the area (see, for example, Figure 5). Due to cut-backs in USEPA funding, however, these measurements were discontinued in 2003.

Table 13a. Primary and Additional Ozone Modeling Results – Lake Michigan and Cleveland Areas (2009)

2009 Modeling Results		Lake Michigan Area								Cleveland Area		
		Chiwaukee	Harr.Beach	Sheboygan	DoorCounty	Holland	Hammond	MichiganCity		Ashtabula	Geauga	Eastlake
		550590019	550890009	551170006	550290004	260050003	180892008	180910005		390071001	390550004	390850003
Attainment Test (based on EPA guidance-2002 baseyear)												
Base Year Design Value (average of three 3-year periods)		*98.3*	*93.0*	*97.0*	*91.0*	*94.0*	*88.3*	*90.3*		*95.7*	*99.0*	*92.7*
RRF (all days > 85 ppb, or at least 10 days)		0.935	0.918	0.916	0.899	0.888	0.980	0.958		0.865	0.897	0.894
Future Year Design Value		**91.9**	**85.4**	**88.9**	**81.8**	83.5	**86.5**	**86.5**		82.8	**88.8**	82.9
Attainment Test (based on EPA guidance-2005 baseyear)												
Base Year Design Value (average of three 3-year periods)		*84.7*	*83.3*	*88.0*	*88.7*	*90.0*	*77.7*	*77.0*		*89.0*	*79.3*	*86.3*
RRF (all days > 85 ppb, or at least 10 days)		0.972	0.961	0.955	0.946	0.948	0.971	0.960		0.937	0.942	0.949
Future Year Design Value		82.3	80.1	84.0	83.9	**85.3**	75.4	73.9		83.4	74.7	81.9
Weight of Evidence (alternative approaches-2002baseyear)												
Alt 1 - Base Year Des. Value (3-year period centered on 2002)		*101.0*	*98.0*	*100.0*	*94.0*	*97.0*	*90.0*	*93.0*		*99.0*	*103.0*	*95.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2002)		*101.0*	*98.0*	*100.0*	*94.0*	*97.0*	*92.0*	*93.0*		*99.0*	*103*	*95.0*
RRF (all days > 85 ppb, or at least 10 days)		0.935	0.918	0.916	0.899	0.888	0.980	0.958		0.865	0.897	0.894
Alt 1 - Future Year Projected Value		**94.4**	**90.0**	**91.6**	84.5	**86.1**	**88.2**	**89.1**		**85.6**	**92.4**	84.9
Alt 2 - Future Year Projected Value		**94.4**	**90.0**	**91.6**	84.5	**86.1**	**90.2**	**89.1**		**85.6**	**92.4**	84.9
Alt 1 - RRF (all days > 70 ppb)		0.933	0.918	0.912	0.907	0.893	0.969	0.947		0.876	0.907	0.900
Alt 1 - Future Year Projected Value		**94.2**	**90.0**	**91.2**	**85.3**	**86.6**	**87.2**	**88.1**		**86.7**	**93.4**	**85.5**
Alt 2 - Future Year Projected Value		**94.2**	**90.0**	**91.2**	**85.3**	**86.6**	**89.1**	**88.1**		**86.7**	**93.4**	**85.5**
Alt 2 - RRF (all days > 85 ppb, or at least 10 days; with acceptable model performance)		0.945	0.904	0.910	0.904	0.887	0.976	0.964		0.866	0.896	0.894
Alt 1 - Future Year Projected Value		**95.4**	**88.6**	**91.0**	**85.0**	**86.0**	**87.8**	**89.7**		**85.7**	**92.3**	84.9
Alt 2 - Future Year Projected Value		**95.4**	**88.6**	**91.0**	**85.0**	**86.0**	**89.8**	**89.7**		**85.7**	**92.3**	84.9
Weight of Evidence (alternative approaches-2005baseyear)												
Alt 1 - Base Year Des. Value (3-year period centered on 2005)		*83.0*	*79.0*	*86.0*	*86.0*	*88.0*	*76.0*	*76.0*		*86.0*	*77.0*	*86.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2005)		*86.0*	*88.0*	*89.0*	*90.0*	*93.0*	*79.0*	*78.0*		*91.0*	*86.0*	*89.0*
Alt 1 - Future Year Projected Value		80.7	75.9	82.1	81.4	83.4	73.8	73.0		80.6	72.5	81.6
Alt 2 - Future Year Projected Value		83.6	84.6	**85.0**	**85.1**	**88.2**	76.7	74.9		**85.3**	81.0	84.5

Table 13b. Primary and Additional Ozone Modeling Results – Cincinnati, Columbus, St. Louis, Indianapolis, and Detroit (2009)

2009 Modeling Results	Cincinnati Area			Columbus	St. Louis Area		Indianapolis Area		Detroit Area
	Wilmington	Lebanon	Sycamore	NewAlbany	W. Alton	OrchardFarm	Noblesville	Fortville	New Haven
	390271002	39165007	390610006	390490029	291831002	291831004	180571001	18059003	260990009
Attainment Test (based on EPA guidance-2002 baseyear)									
Base Year Design Value (average of three 3-year periods)	*94.3*	*90.7*	*90.7*	*94.0*	*90.0*	*90.0*	*93.7*	*91.3*	*92.3*
RRF (all days > 85 ppb, or at least 10 days)	0.885	0.908	0.938	0.888	0.947	0.914	0.894	0.918	0.924
Future Year Design Value	83.5	82.4	**85.1**	83.5	**85.2**	82.3	83.8	83.8	**85.3**
Attainment Test (based on EPA guidance-2005 baseyear)									
Base Year Design Value (average of three 3-year periods)	*82.3*	*87.7*	*84.3*	*86.3*	*86.3*	*87.0*	*83.3*	*78.7*	*86.0*
RRF (all days > 85 ppb, or at least 10 days)	0.941	0.947	0.967	0.947	0.938	0.942	0.945	0.947	0.947
Future Year Design Value	77.4	83.1	81.5	81.7	80.9	82.0	78.7	74.5	81.4
Weight of Evidence (alternative approaches-2002baseyear)									
Alt 1 - Base Year Des. Value (3-year period centered on 2002)	*96.0*	*92.0*	*93.0*	*95.0*	*91.0*	*92.0*	*96.0*	*94.0*	*97.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2002)	*96.0*	*92.0*	*93.0*	*96.0*	*91.0*	*92.0*	*96.0*	*94.0*	*97.0*
RRF (all days > 85 ppb, or at least 10 days)	0.885	0.908	0.938	0.888	0.947	0.914	0.894	0.918	0.924
Alt 1 - Future Year Projected Value	**85.0**	83.5	**87.2**	84.4	**86.2**	84.1	**85.8**	**86.3**	**89.6**
Alt 2 - Future Year Projected Value	**85.0**	83.5	**87.2**	**85.2**	**86.2**	84.1	**85.8**	**86.3**	**89.6**
Alt 1 - RRF (all days > 70 ppb)	0.885	0.914	0.940	0.901	0.945	0.911	0.912	0.907	0.918
Alt 1 - Future Year Projected Value	**85.0**	84.1	**87.4**	**85.6**	**86.0**	83.8	**87.6**	**85.3**	**89.0**
Alt 2 - Future Year Projected Value	**85.0**	84.1	**87.4**	**86.5**	**86.0**	83.8	**87.6**	**85.3**	**89.0**
Alt 2 - RRF (all days > 85 ppb, or at least 10 days; with acceptable model performance)	0.880	0.911	0.940	0.886	0.951	0.913	0.894	0.916	0.935
Alt 1 - Future Year Projected Value	84.5	83.8	**87.4**	84.2	**86.5**	84.0	**85.8**	**86.1**	**90.7**
Alt 2 - Future Year Projected Value	84.5	83.8	**87.4**	**85.1**	**86.5**	84.0	**85.8**	**86.1**	**90.7**
Weight of Evidence (alternative approaches-2005baseyear)									
Alt 1 - Base Year Des. Value (3-year period centered on 2005)	*80.0*	*86.0*	*81.0*	*84.0*	*85.0*	*86.0*	*80.0*	*76.0*	*82.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2005)	*85.0*	*89.0*	*86.0*	*88.0*	*89.0*	*89.0*	*87.0*	*81.0*	*90.0*
Alt 1 - Future Year Projected Value	75.3	81.4	78.3	79.5	79.7	81.0	75.6	72.0	77.7
Alt 2 - Future Year Projected Value	80.0	84.3	83.2	83.3	83.5	83.8	82.2	76.7	**85.2**

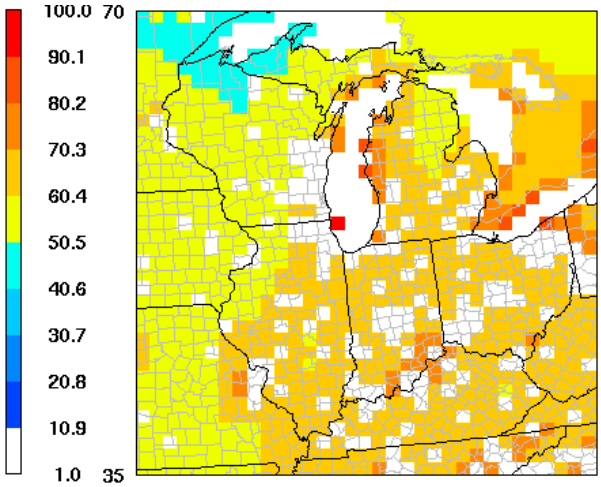


Figure 64. Estimated Future Year Values (unmonitored grid cells)

Finally, EPA's latest regional ozone modeling was considered as corroborative information. This modeling was performed as part of the June 2007 proposal to revise the ozone standard (EPA, 2007b). EPA applied the CMAQ model with 2001 meteorology to first estimate ozone levels in 2020 based on the current standard and national rules in effect or proposed (i.e., the baseline), and then to evaluate strategies for attaining a more stringent (70 ppb) primary standard. Baseline (2020) ozone levels were predicted to be below the current standard in 481 of the 491 counties with ozone monitors. Of the 10 counties predicted to be above the standard, there is one county in the LADCO region (i.e., Kenosha County, WI at 86 ppb). This result is consistent with LADCO's Base K modeling for 2018 (i.e., Kenosha County, WI at 86.7 ppb), which is not surprising given that EPA's modeling and LADCO's Base K modeling have a similar base year (2001 v. 2002).

Analysis of Trends: EPA's modeling guidelines note that while air quality models are generally the most appropriate tools for assessing the expected impacts of a change in emissions, it may also be possible to extrapolate future trends based on measured historical trends of air quality and emissions. To do so, USEPA's guidance suggests that ambient trends should first be normalized to account for year-to-year variations in meteorological conditions (EPA, 2002). Meterologically-adjusted 4th high 8-hour ozone concentrations were derived using the air quality – meteorological regression model developed by EPA (i.e., Cox method – see Section 2.1).

The historical trend in these met-adjusted ozone concentrations were extrapolated to estimate future year ozone concentrations based on historical and projected trends in precursor emissions. Both VOC and NOx emissions affect ozone concentrations. Given that observation-based methods show that urban areas in the region are generally VOC-limited and rural areas in the region are NOx-limited (see Section 2.1), urban VOC emissions and regional NOx emissions are considered important. The trends in urban VOC and regional NOx emissions were calculated to produce appropriate weighting factors.

The resulting 2009 and 2012 ozone values are provided in Figure 65, along with the primary and alternative modeling ozone values for key sites in the Lake Michigan, Cleveland, and Cincinnati areas. The results reflect a fairly wide scatter, but, on balance, the supplemental information is supportive of the primary modeling results (i.e., sites in the Lake Michigan area and Cleveland are expected to be close to the standard).

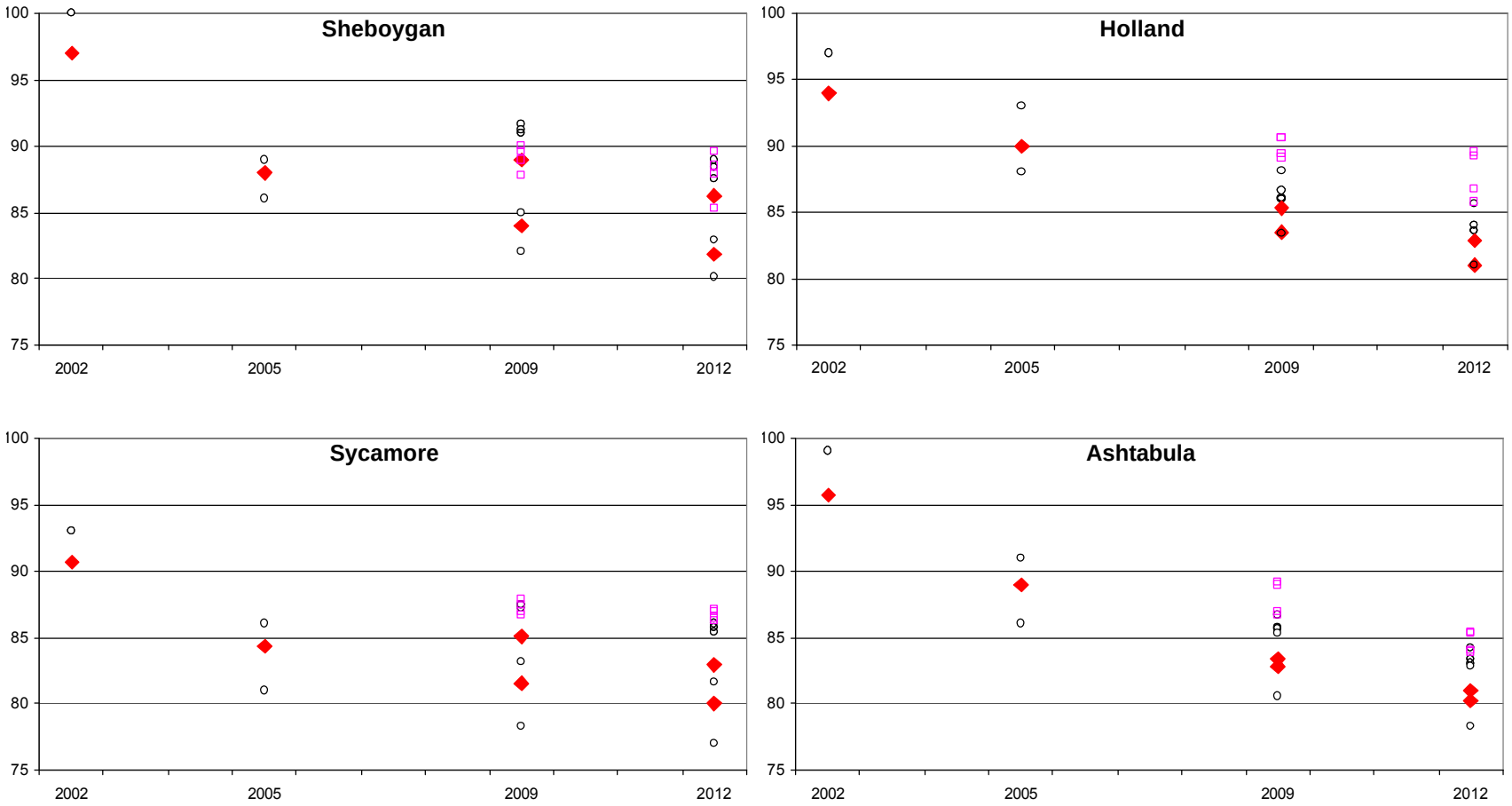


Figure 65. Estimates of Future Year Ozone Concentrations – Lake Michigan Area (Sheboygan and Holland), Cincinnati (Sycamore), and Cleveland (Ashtabula)

Note: Primary (guideline) modeling values (Base K and Base M results) are represented by large red diamonds, additional modeling values by small black circles, and trends-based values by small pink squares

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., MAPPER) is presented in Section 3. The key findings from this modeling are that most urban areas are VOC-limited and rural areas are NOx-limited.

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007a). Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 66) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and biogenic sources) at ozone monitoring sites in the region.

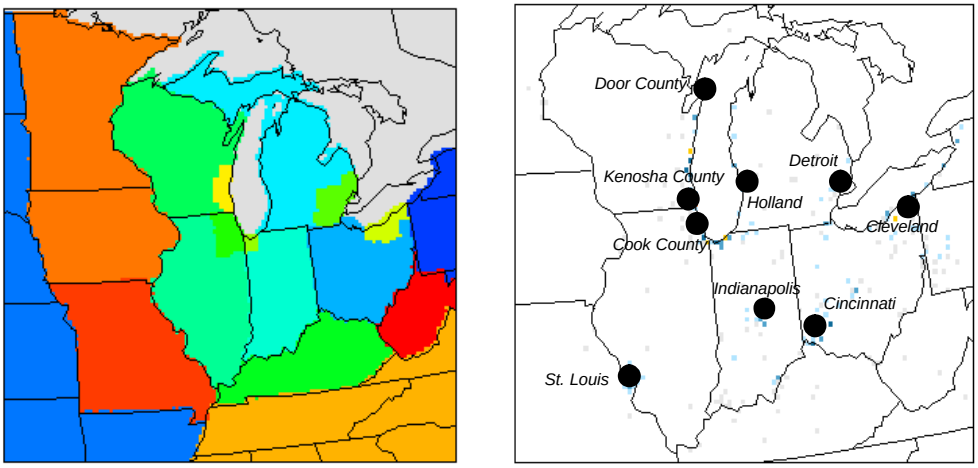


Figure 66. Source regions (left) and key monitoring sites (right) for ozone modeling analysis

Modeling results for 2009 (Base M) and 2012 (Base K) are provided in Appendix II for several key monitoring sites. For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of percentages. (Note, in the sector-level graph, the contributions from NOx emissions are shown in blue, and from VOC emissions in green.)

The sector-level results (see, for example, Figure 67) show that on-road and nonroad NOx emissions generally have the largest contributions at the key monitor locations (> 15% each). EGU and non-EGU NOx emissions are also important contributors (> 10% each). The source group contributions vary by receptor location due to emissions inventory differences.

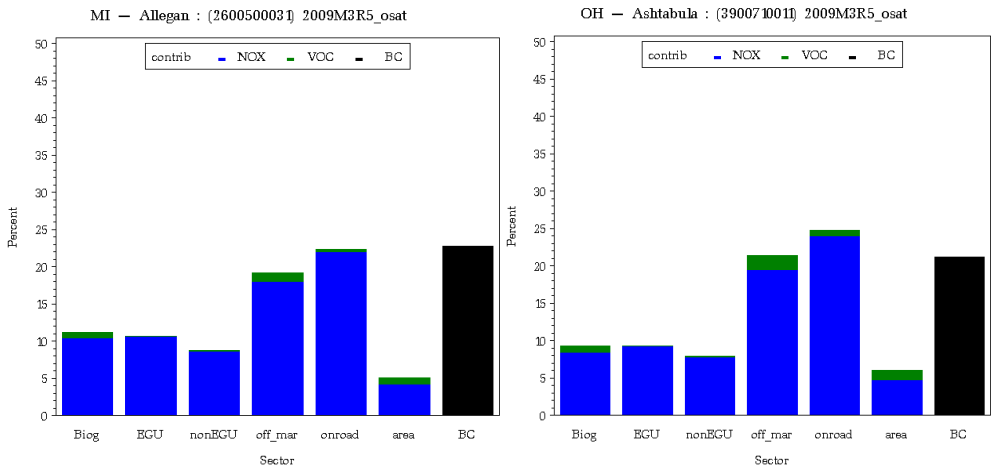


Figure 67. Source-sector results for Holland (left) and Ashtabula (right) monitors – 2009 (Base M)

The source region results (see, for example, Figure 68) show that while nearby areas generally have the highest impacts (e.g., the northeastern IL/northwestern IN/southeastern WI nonattainment area contributes 25-35% to high sites in the Lake Michigan area, and Cleveland nonattainment counties contribute 20-25% to high sites in northeastern Ohio), there is an even larger regional impact (i.e., contribution from other states).

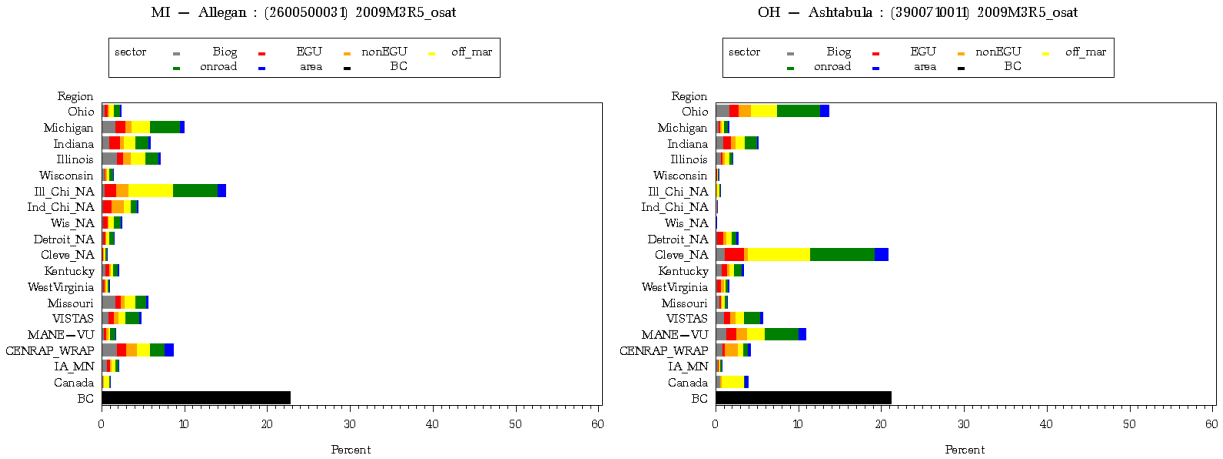


Figure 68. Source-region results for Holland (left) and Ashtabula (right) monitors – 2009 (Base M)

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year ozone concentrations. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to produce significant improvement in ozone air quality.
- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. As noted above, 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).
- Most sites are expected to meet the current 8-hour standard by the applicable attainment date, except, for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.
- Current monitoring data show significant nonattainment in these areas (e.g., peak design values on the order of 90 – 93 ppb). It is not clear whether sufficient emission reductions will occur in the next couple of years to provide for attainment.
- Attainment by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). On the other hand, if either of these conditions is not met, then attainment may be less likely.

4.3 Weight-of-Evidence Determination for $PM_{2.5}$

The WOE determination for $PM_{2.5}$ consists of the primary modeling and other supplemental analyses. A summary of this information is provided below.

Primary (Guideline) Modeling: The results of the guideline modeling are presented in Section 4.1. Key findings from this modeling include:

- Base M regional modeling shows attainment by 2009 at all sites, except Detroit, Cleveland, and Granite City, and attainment at all sites by 2012, except for Detroit and Granite City.

  The regional modeling for $PM_{2.5}$ does not reflect any air quality benefit expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$

- Base K modeling results reflect generally higher future year values, and show more sites in nonattainment in 2009 and 2012 compared to the Base M modeling. The difference in the two modeling analyses is due mostly to lower base year design values in Base M.

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for $PM_{2.5}$ should reflect a weight-of-evidence approach, with consideration of monitoring based information.

- Base M modeling also shows that the new $PM_{2.5}$ 24-hour standard will not be met at many sites, even by 2018, with existing controls.

Additional Modeling: EPA's latest regional $PM_{2.5}$ modeling was considered as corroborative information. This modeling was performed as part of the September 2006 revision to the $PM_{2.5}$ standard (USEPA, 2006). EPA applied the CMAQ model with 2001 meteorology to estimate $PM_{2.5}$ levels in 2015 and 2020 first with national rules in effect or proposed, and then with additional controls to attain the current standard (15 ug/m^3 annual/65 ug/m^3 daily). Additional analyses were performed to evaluate strategies for attaining more stringent standards in 2020 (15/35, and 14/35). Baseline (2015) $PM_{2.5}$ levels were predicted to be above the current standard in four counties in the LADCO region: Madison County, IL at 15.2 ug/m^3, Wayne County, MI at 17.4, Cuyahoga County, OH at 15.4, and Scioto County, OH at 15.6. These results are consistent with LADCO's Base K modeling for 2012/2018, which is not surprising given that EPA's modeling and LADCO's Base K modeling have a similar base year (2001 v. 2002).

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., application of thermodynamic equilibrium models) is presented in Section 3. The key findings from this modeling are that $PM_{2.5}$ mass is sensitive to reductions in sulfate, nitric acid, and ammonia concentrations. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases. Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007b). Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 69) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and biogenic sources) at $PM_{2.5}$ monitoring sites in the region.

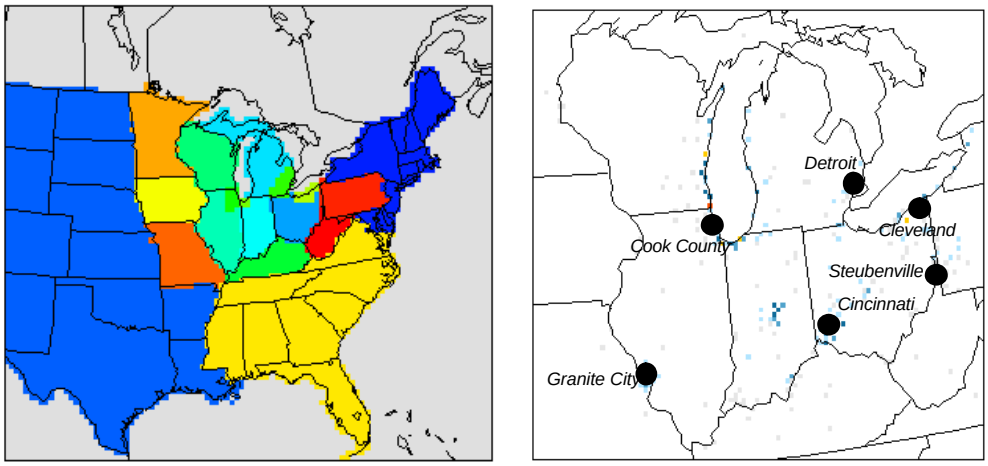


Figure 69. Source regions (left) and key monitoring sites (right) for $PM_{2.5}$ modeling analysis

Modeling results for 2012 (Base K) and 2018 (Base M) are provided in Appendix III for several key monitoring sites. For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of absolute modeled values.

The sector-level results (see, for example, Figure 70) show that EGU sulfate, non-EGU-sulfate, and area organic carbon emissions generally have the largest contributions at the key monitor locations (> 15% each). Ammonia emissions are also important contributors (> 10%). The source group contributions vary by receptor location due to emissions inventory differences.

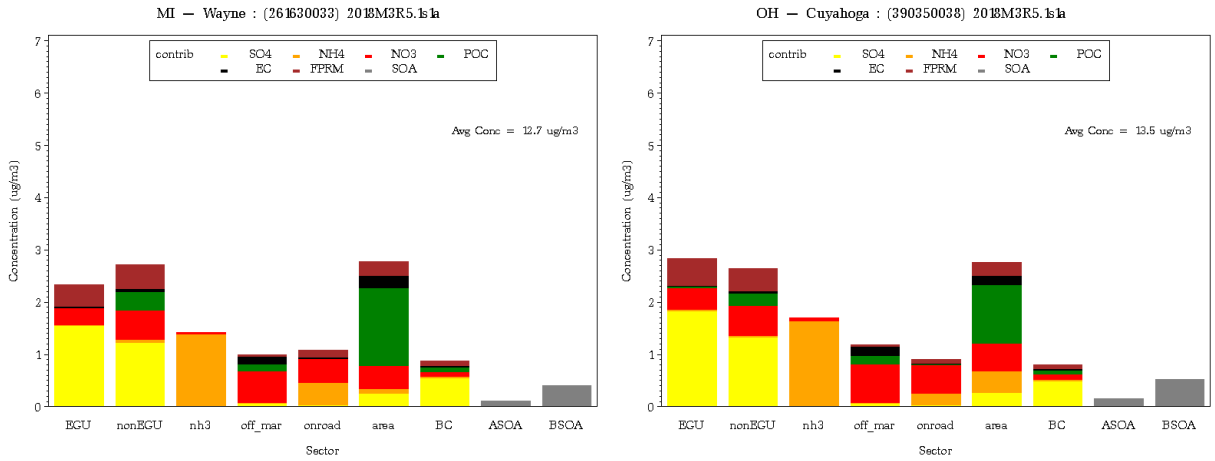


Figure 70. Source-sector results for Detroit (left) and Cleveland (right) monitors – 2018 (Base M)

The source region results (see, for example, Figure 71) show that while nearby areas generally have the highest impacts (e.g., Detroit nonattainment counties contribute 40% to high sites in southeastern Michigan, and Cleveland nonattainment counties contribute 35% to high sites in northeastern Ohio), there is an even larger regional impact (i.e., contribution from other states).

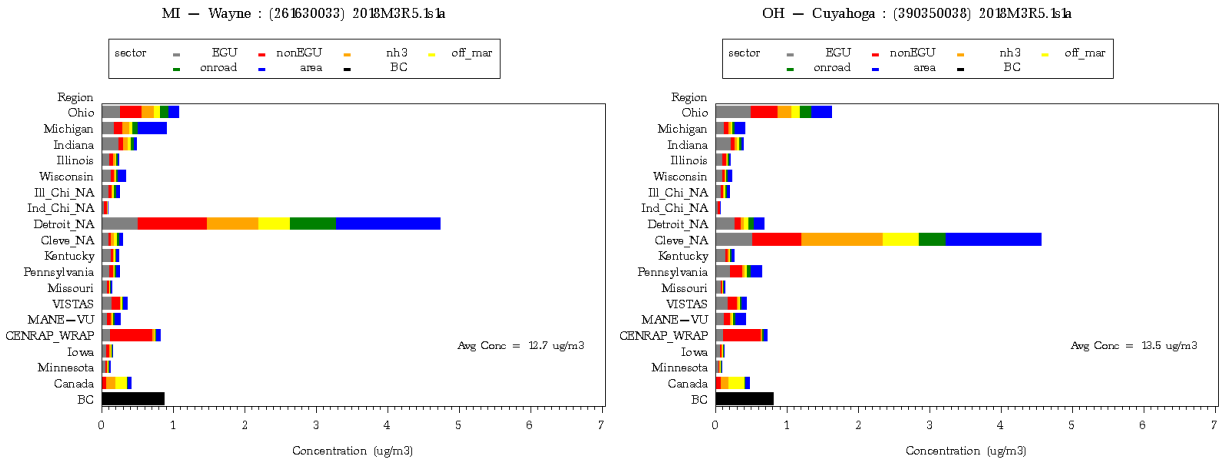


Figure 71. Source-region results for Detroit (left) and Cleveland (right) monitors – 2018 (Base M)

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year $PM_{2.5}$ concentrations. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to produce significant improvement in $PM_{2.5}$ air quality.
- The choice of the base year affects the future year model projections. It is not clear how much of this is attributable to differences in meteorology, because, as noted in Section 3, $PM_{2.5}$ concentrations are not as strongly influenced by meteorology as ozone.
- Most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.
- Current monitoring data show significant nonattainment in these areas (e.g., peak design values on the order of 16 – 17 ug/m^3). It is not clear whether sufficient emission reductions will occur in the next couple of years to provide for attainment. States are conducting local-scale analyses for Detroit, Cleveland, and Granite City, in particular, to identify appropriate additional local controls.
- Attainment by the applicable attainment date is dependent (possibly) on actual future year meteorology and (more likely) on actual future year emissions (e.g., if the emission reductions associated with the "on the books" controls are achieved, then attainment is likely). On the other hand, if either of these conditions is not met (especially, with respect to emissions), then attainment may be less likely.

Section 5. Reasonable Progress Assessment for Regional Haze

Air quality modeling and other information were used to assess the improvement in visibility that would be provided by existing ("on the books") controls and possible additional control programs. In determining reasonable progress for regional haze, Section 169A of the Clean Air Act and EPA's visibility rule requires states to consider five factors:

- costs of compliance
- time necessary for compliance
- energy and non-air quality environmental impacts of compliance
- remaining useful life of any existing source subject to such requirements
- uniform rate of visibility improvement needed to attain natural visibility conditions by 2064

The uniform rate of visibility improvement requirement can be depicted graphically in the form of a "glide path" (see Figure 72).

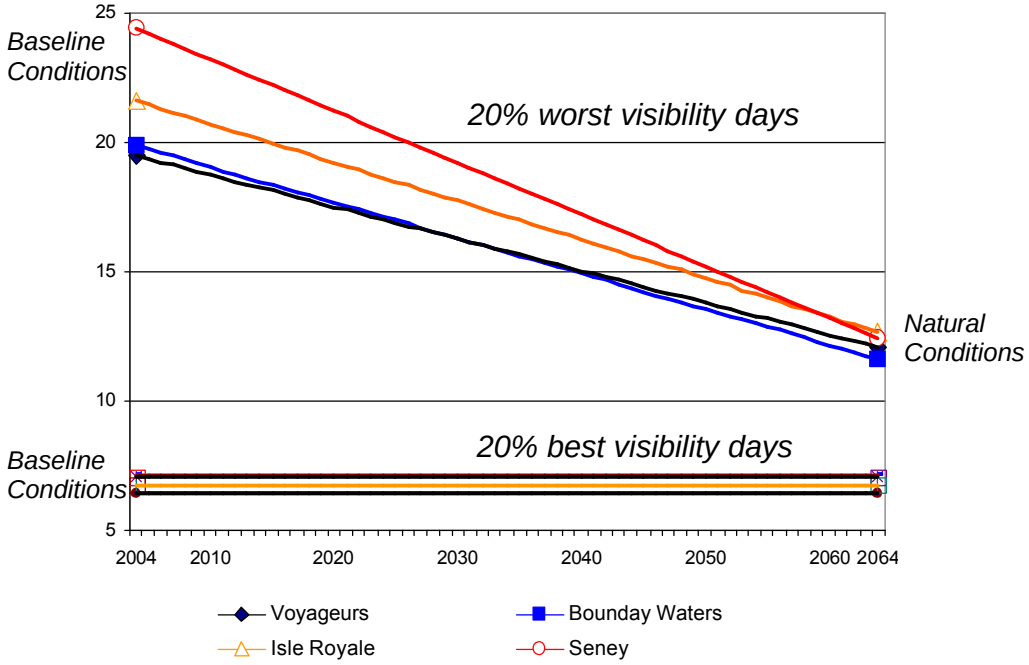


Figure 72. Visibility "glide paths" for northern Class I areas (units: deciviews)

5.1 Class I Areas Impacted

EPA's visibility rule requires a state to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." (40 CFR Part 51.308(d)) To meet this requirement, technical analyses conducted by the RPOs were consulted to obtain information on areas of influence and culpability for Class I areas in the eastern U.S. (MRPO, 2007). A summary of this information is provided in Table 1 (MRPO, 2007). The table shows that every LADCO State impacts multiple Class I areas in the eastern U.S.

Table 14. Draft List of Class I Areas Impacted by LADCO States

AREA NAME	IL	IN	MI	OH	WI
81.401 Alabama.					
Sipsey Wilderness Area	(1)	(1)			
81.404 Arkansas.					
Caney Creek Wilderness Area	(2), (4)	(2), (4)		(2), (4)	
Upper Buffalo Wilderness Area	(1),(2),(4),(5)	(2), (4)		(2), (4)	(2)
81.408 Georgia.					
Cohotta Wilderness Area					
Okefenokee Wilderness Area					
Wolf Island Wilderness Area					
81.411 Kentucky.					
Mammoth Cave NP	(1), (2), (5)	(1), (2), (5)	(1), (2)	(1), (2), (5)	
81.412 Louisiana.					
Breton Wilderness Area					
81.413 Maine.					
Acadia National Park	(3)	(3)	(3)	(3)	
Moosehorn Wilderness Area.	(3)	(3)	(3)	(3)	
81.414 Michigan.					
Isle Royale NP.	(1), (2)	(1), (2)	(1), (2)		(1), (2)
Seney Wilderness Area	(1), (2)	(1), (2)	(1), (2)	(1), (2)	(1), (2)
81.415 Minnesota.					
Boundary Waters Canoe Area Wilderness	(2)	(2)	(2)		(1), (2)
Voyageurs NP	(2)	(2)			(1), (2)
81.416 Missouri.					
Hercules-Glades Wilderness Area	(2), (4), (5)	(2), (4), (5)		(2), (4)	(2)
Mingo Wilderness Area	(2), (4), (5)	(2), (4), (5)	(2)	(2), (4)	(2)
81.419 New Hampshire.					
Great Gulf Wilderness Area	(3)	(3)	(3)	(1), (3)	
Pres. Range-Dry River Wilderness Area.					
81.42 New Jersey.					
Brigantine Wilderness Area	(3)	(3)	(1), (3)	(1), (3)	

81.422 North Carolina.					
Great Smoky Mountains NP{1}	(1)	(1)		(1)	
Joyce Kilmer-Slickrock Wilderness Area{2}					
Linville Gorge Wilderness Area.					
Shining Rock Wilderness Area.					
Swanquarter Wilderness Area					
81.426 South Carolina.					
Cape Romain Wilderness					
81.428 Tennessee.					
Great Smoky Mountains NP{1}.	(1)	(1)		(1)	
Joyce Kilmer-Slickrock Wilderness{2}					
81.431 Vermont.					
Lye Brook Wilderness	(2), (3)	(2), (3)	(2), (3)	(1), (2), (3)	
81.433 Virginia.					
James River Face Wilderness.	(2)	(2)	(2)	(2), (5)	
Shenandoah NP	(2), (3)	(1), (2), (3)	(2), (3)	(1),(2),(3),(5)	
81.435 West Virginia.					
Dolly Sods/Otter Creek Wilderness.	(2), (3)	(1), (2), (3)	(1), (2), (3)	(1),(2),(3),(5)	

Key
(1) MRPO Back Trajectory Analyses
(2) MRPO PSAT Modeling
(3) MANE-VU Contribution Assessment
(4) Missouri-Arkansas Contribution Assessment
(5) VISTAS Areas of Influence

5.2 Future Year Modeling Results

For regional haze, the calculation of future year conditions assumed:

- baseline concentrations based on 2000-2004 IMPROVE data, with updated (subsitituted) data for Mingo, Boundary Waters, Voyageurs, Isle Royale, and Seney (see Section 2.3);
- use of the new IMPROVE light extinction equation; and
- use of EPA default values for natural conditions, based on the new IMPROVE light extinction equation.

The uniform rate of visibility improvement values for the 2018 planning year were derived (for the 20% worst visibility days) based on a straight line between baseline concentration value (plotted in the year 2004 -- end year of the 5-year baseline period) and natural condition value (plotted in the year 2064 -- date for achieving natural conditions). Plots of these "glide paths" with the Base M modeling results are presented in Figure 73 for Class I areas in the eastern U.S. A tabular summary of measured baseline and modeled future year deciview values for these Class I areas are provided in Table 15 (2002 base year) and Table 16 (2005 base year)[13].

The haze results show that several Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values (in 2018), including those in northern Michigan and several in the northeastern U.S. Many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values (in 2018). As noted above, states should consider these results, along with information on the other four factors, in setting reasonable progress goals.

An assessment of the five factors was performed for LADCO and the State of Minnesota by a contractor (EC/R, 2007). Specifically, ECR examined reductions in SO2 and NOx emissions from EGUs and industrial, commercial and institutional (ICI) boilers; NOx emissions from mobile sources and reciprocating engines and turbines; and ammonia emissions from agricultural operations. The impacts of "on the books" controls were also examined to provide a frame of reference for assessing the impacts of the additional control measures.

The results of ECR's analysis of the five factors are summarized below:

> Factor 1 (Cost of Compliance): The average cost effectiveness values (in terms of $M per ton) are provided in Table 16. For comparison, cost-effectiveness estimates previously provided for "on the books" controls include:
>
> CAIR SO2: $700 - $1,200, NOx: $1,400 – $2.600 ($/T)
>
> BART SO2: $300 - $963, NOx: $248 - $1,770
>
> MACT SO2: $1,500, NOx: $7,600
>
> Most of the cost-effectiveness values for the additional controls are within the range of cost-effectiveness values for "on the books" controls.

[13] Model results reflect the grid cell where the IMPROVE monitor is located.

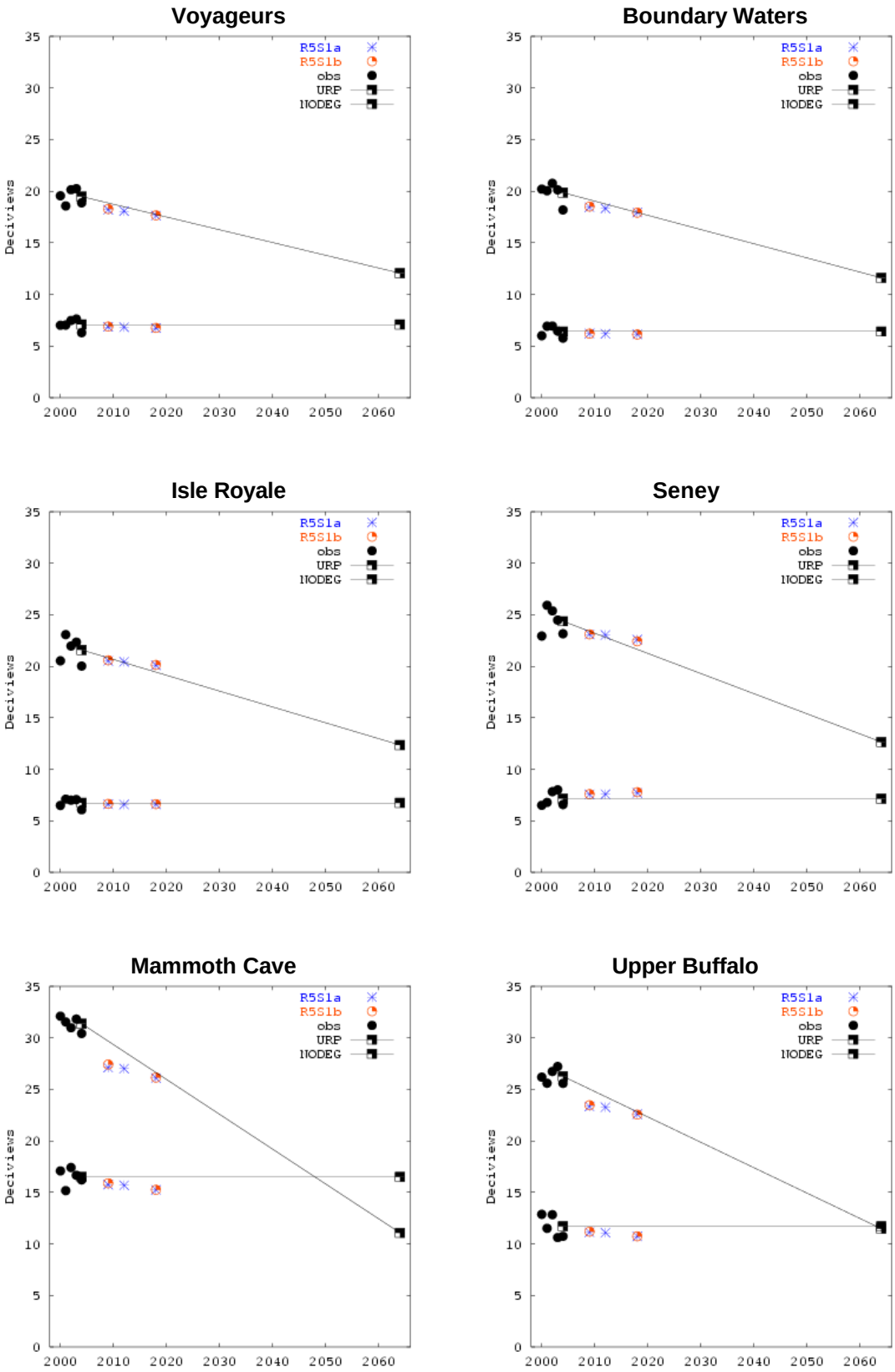


Figure 73. Visibility modeling results for Class I areas in eastern U.S.

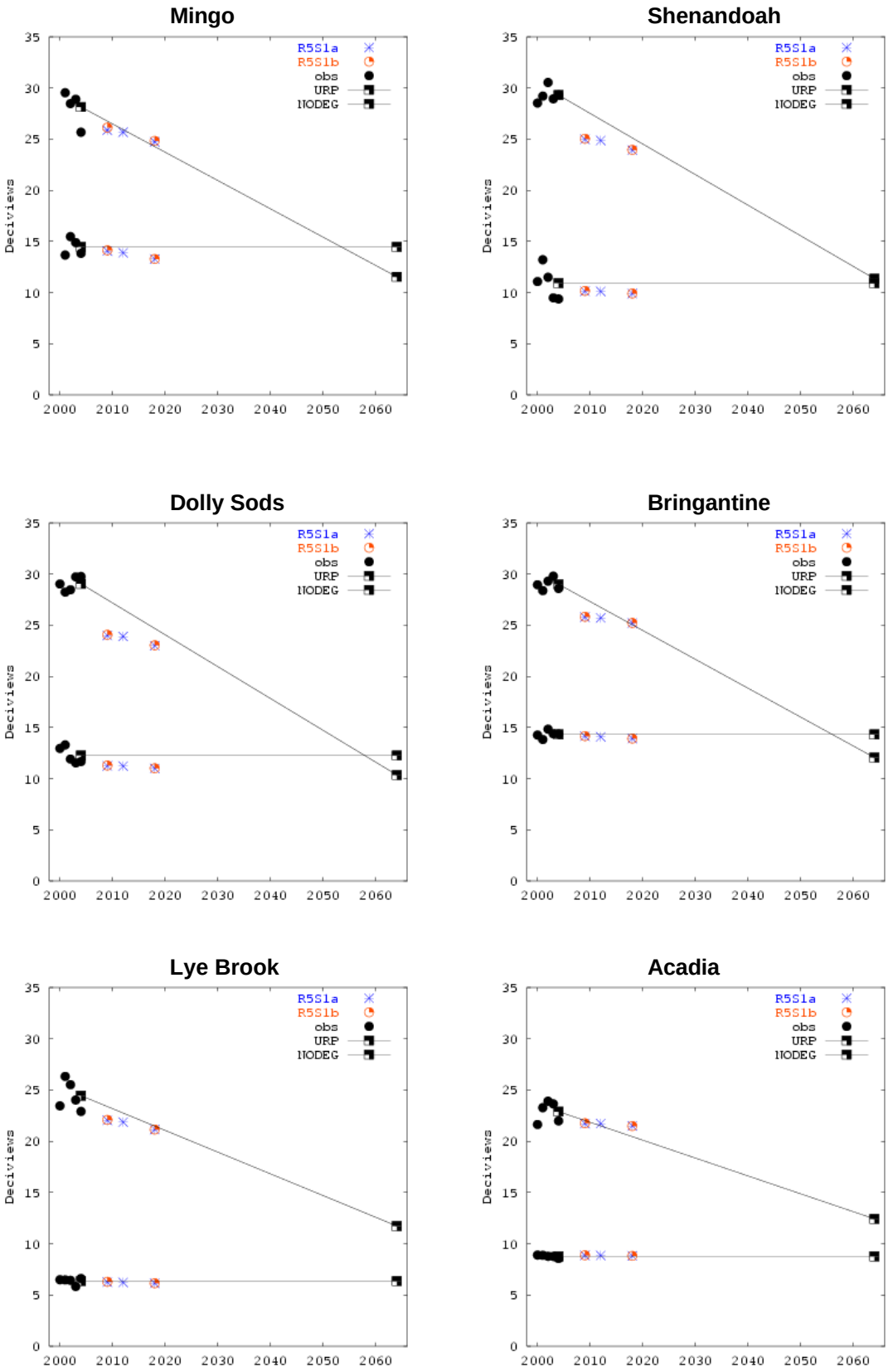


Figure 73 (cont.) Visibility modeling results for Class I areas in eastern U.S.

Table 15. Haze Results - Round 4 (Based on 2000-2004)							
Worst 20%		**2018**	**2009**	**2012**	**2018**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**EGU2 (5-state region)**	**EGU2 (12-state region)**
BOWA1	19.86	17.70	19.05	19.01	**18.94**	**18.40**	17.72
VOYA2	19.48	17.56	19.14	19.19	**19.18**	**18.94**	**18.38**
SENE1	24.38	21.35	22.98	22.71	**22.38**	21.26	20.63
ISLE1	21.59	19.21	20.46	20.28	**20.04**	19.09	18.64
HEGL1	26.75	22.76	24.73	24.34	**23.85**	**23.01**	22.04
MING1	28.15	24.08	25.18	24.67	24.01	22.53	21.45
CACR1	26.36	22.55	24.01	23.55	**22.99**	22.43	21.57
UPBU1	26.27	22.47	24.02	23.58	**23.06**	22.31	21.38
MACA1	31.37	26.14	28.06	27.03	25.52	24.27	22.57
DOSO1	29.04	24.23	24.86	23.59	22.42	21.60	20.15
SHEN1	29.31	24.67	24.06	22.79	21.57	20.43	19.42
JARI1	29.12	24.48	24.81	23.79	22.42	21.59	20.88
BRIG1	29.01	24.68	25.87	25.25	24.39	23.91	23.45
LYBR1	24.45	21.16	21.80	21.32	20.69	20.18	19.79
Best 20%		**2018**	**2009**	**2012**	**2018**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**EGU2 (5-state region)**	**EGU2 (12-state region)**
BOWA1	6.42	6.42	6.71	6.73	6.87	6.83	6.81
VOYA2	7.09	7.09	7.21	7.25	7.34	7.31	7.26
SENE1	7.14	7.14	7.19	7.19	7.23	7.06	6.91
ISLE1	6.75	6.75	6.57	6.51	6.47	6.20	6.06
HEGL1	12.84	12.84	12.61	12.62	12.61	12.43	12.02
MING1	14.46	14.46	13.96	13.93	13.94	13.74	13.33
CACR1	11.24	11.24	10.91	10.92	10.90	10.75	10.42
UPBU1	11.71	11.71	11.47	11.46	11.42	11.28	11.01
MACA1	16.51	16.51	16.06	15.91	15.54	15.18	14.75
DOSO1	12.28	12.28	11.72	11.45	11.19	10.93	10.67
SHEN1	10.93	10.93	9.73	9.53	9.17	9.05	8.90
JARI1	14.21	14.21	13.56	13.33	12.97	12.65	12.46
BRIG1	14.33	14.33	13.74	13.69	13.47	13.32	13.21
LYBR1	6.36	6.36	6.12	6.05	5.96	5.88	5.82

Table 16. Haze Results - Round 5.1 (Based on 2000-2004)						
Worst 20%		**2018**	**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	19.86	17.94	18.45	18.33	17.94	17.92
VOYA2	19.48	17.75	18.20	18.07	17.63	17.66
SENE1	24.38	21.64	23.10	23.04	**22.59**	**22.42**
ISLE1	21.59	19.43	20.52	20.43	**20.09**	**20.13**
ISLE9	21.59	19.43	20.33	20.22	**19.84**	**19.82**
HEGL1	26.75	23.13	24.72	24.69	**24.22**	**24.17**
MING1	28.15	24.27	25.88	25.68	**24.74**	**24.83**
CACR1	26.36	22.91	23.39	23.29	22.44	22.40
UPBU1	26.27	22.82	23.34	23.27	22.59	22.55
MACA1	31.37	26.64	27.11	27.01	26.10	26.15
DOSO1	29.05	24.69	24.00	23.90	23.00	23.04
SHEN1	29.31	25.12	24.99	24.87	23.92	23.95
JARI1	29.12	24.91	25.17	25.01	24.06	24.12
BRIG1	29.01	25.05	25.79	25.72	**25.21**	**25.22**
LYBR1	24.45	21.48	22.04	21.86	21.14	21.14
ACAD1	22.89	20.45	21.72	21.72	**21.49**	**21.49**
Best 20%		**2018**	**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**Max**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	6.42	6.42	6.21	6.19	6.14	6.12
VOYA2	7.09	7.09	6.86	6.83	6.75	6.76
SENE1	7.14	7.14	7.57	7.58	7.71	7.78
ISLE1	6.75	6.75	6.62	6.59	6.60	6.62
ISLE9	6.75	6.75	6.56	6.55	6.52	6.50
HEGL1	12.84	12.84	12.51	12.32	11.66	11.64
MING1	14.46	14.46	14.07	13.89	13.28	13.29
CACR1	11.24	11.24	10.88	10.85	10.52	10.52
UPBU1	11.71	11.71	11.13	11.08	10.73	10.74
MACA1	16.51	16.51	15.76	15.69	15.25	15.25
DOSO1	12.28	12.28	11.25	11.23	11.00	11.01
SHEN1	10.93	10.93	10.13	10.11	9.91	9.91
JARI1	14.21	14.21	13.38	13.38	13.14	13.14
BRIG1	14.33	14.33	14.15	14.08	13.92	13.92
LYBR1	6.37	6.37	6.25	6.23	6.14	6.15
ACAD1	8.78	8.78	8.86	8.86	8.82	8.82

Table 17. Estimated Cost Effectiveness for Potential Control Measures

			Average Cost effectiveness ($/ton)		
Emission category	Control strategy	Region	SO2	NOX	NH3
EGU	EGU1	3-State	1,540	2,037	
		9-State	1,743	1,782	
	EGU2	3-State	1,775	3,016	
		9-State	1,952	2,984	
ICI boilers	ICI1	3-State	2,992	2,537	
		9-State	2,275	1,899	
	ICI Workgroup	3-State	2,731	3,814	
		9-State	2,743	2,311	
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	3-State		538	
		9-State		506	
	Turbines emitting 100 tons/year or more	3-State		754	
		9-State		754	
	Reciprocating engines emitting 10 tons/year or more	3-State		1,286	
		9-State		1,023	
	Turbines emitting 10 tons/year or more	3-State		800	
		9-State		819	
Agricultural sources	10% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
	15% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
Mobile sources	Low-NOX Reflash	3-State		241	
		9-State		241	
	MCDI	3-State		10,697	
		9-State		2,408	
	Anti-Idling	3-State		(430) - 1,700	
		9-State		(430) - 1,700	
	Cetane Additive Program	3-State		4,119	
		9-State		4,119	
Cement Plants	Process Modification	Michigan		-	
	Conversion to dry kiln	Michigan		9,848	
	LoTox™	Michigan		1,399	
Glass Manufacturing	LNB	Wisconsin		1,041	
	Oxy-firing	Wisconsin		2,833	
	Electric boost	Wisconsin		3,426	
	SCR	Wisconsin		1,054	
	SNCR	Wisconsin		1,094	
Lime Manufacturing	Mid-kiln firing	Wisconsin		688	
	LNB	Wisconsin		837	
	SNCR	Wisconsin		1,210	
	SCR	Wisconsin		5,037	
	FGD	Wisconsin		128 - 4,828	
Oil Refinery	LNB	Wisconsin		3,288	
	SNCR	Wisconsin		4,260	
	SCR	Wisconsin		17,997	
	LNB+FGR	Wisconsin		4,768	
	ULNB	Wisconsin		2,242	
	FGD	Wisconsin		1,078	

Factor 2 (Time Necessary for Compliance): All of the control measures can be implemented by 2018. Thus, this factor can be easily addressed.

Factor 3 (Energy and Non-Air Quality Environmental Impacts): The energy and other environmental impacts are believed to be manageable. For example, the increased energy demand from add-on control equipment is less than 1% of the total electricity and steam production in the region, and solid waste disposal and wastewater treatment costs are less than 5% of the total operating costs of the pollution control equipment. It should also be noted that the SO2 and NOx controls would have beneficial environmental impacts (e.g., reduced acid deposition and nitrogen deposition).

Factor 4 (Remaining Useful Life): The additional control measures are intended to be market-based strategies applied over a broad geographic region. It is not expected that the control requirements will be applied to units that will be retired prior to the amortization period for the control equipment. Thus, this factor can be easily addressed.

Factor 5 (Visibility Impacts): The estimated incremental improvement in 2018 visibility levels for the additional measures is shown in Figure 74, along with the cost-effectiveness expressed in $M per deciview improvement). These results show that although EGU and ICI boiler controls have higher cost-per-deciview values (compared to some of the other measures), their visibility impacts are larger.

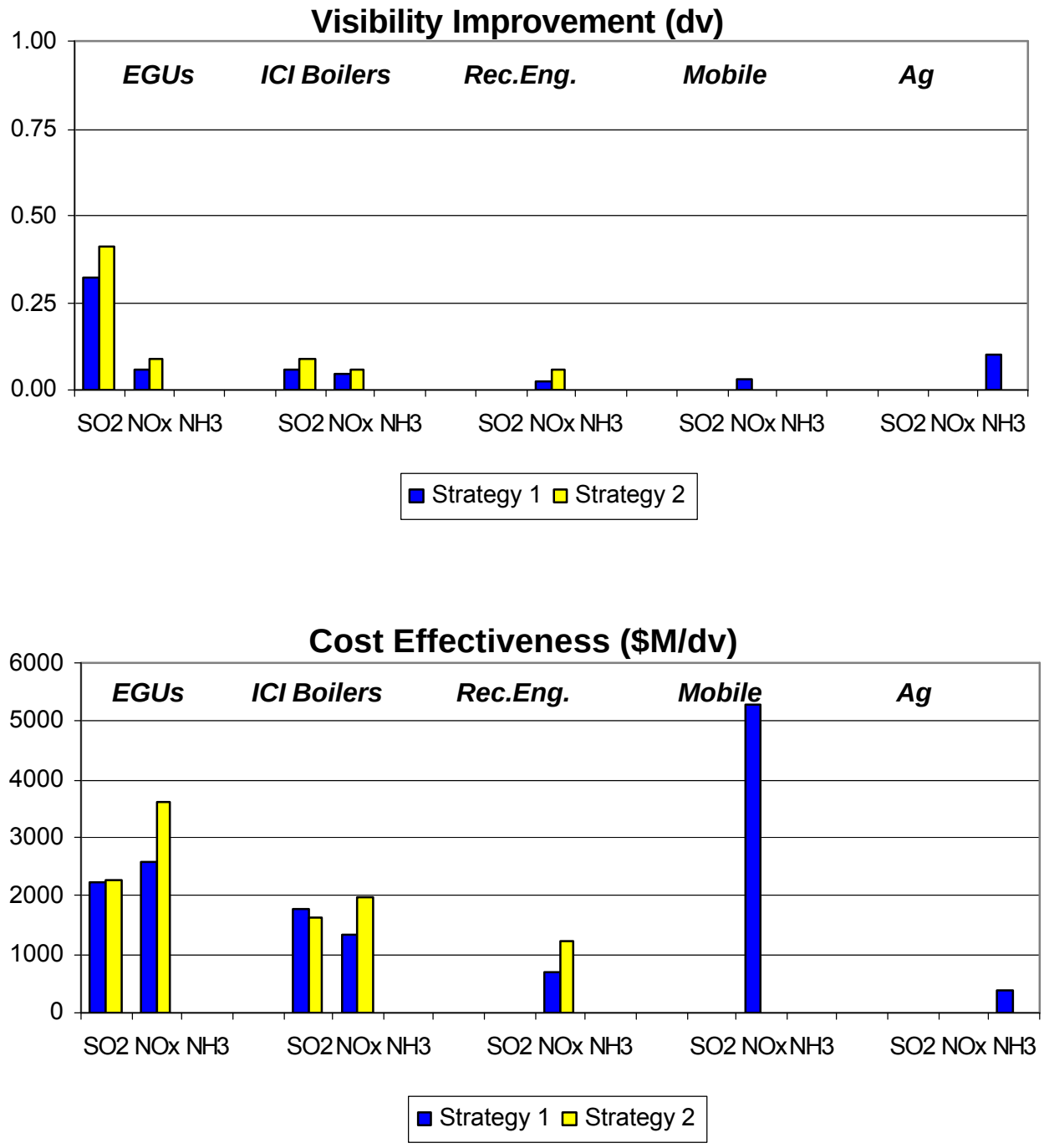


Figure 74. Results of ECR analysis of reasonable progress factors – visibility improvement (Factor 5) is on top, and cost effectiveness (Factor 1) is on bottom

5.3 Weight-of-Evidence Determination for Haze

The WOE determination for haze consists of the primary modeling and other supplemental analyses. A summary of this information is provided below.

Primary (Guideline) Modeling: The results of the guideline modeling are presented in Section 4.1. Key findings from this modeling include:

- Base M modeling results show that the northern Minnesota Class I areas are close to the glide path, whereas the northern Michigan Class I areas are above the glide path in 2018. Other sites in the eastern U.S. are close to (or below) the glide path, except for Mingo (MO), Brigantine (NJ), and Acadia (ME).

- Base K modeling results show that the northern Minnesota and northern Michigan Class I areas are above the glide path in 2018. Other sites in the eastern U.S. are close to (or below) the glide path.

- The difference in the two modeling analyses is due mostly to differences in future year emission projections, especially for EGUs (e.g., use of IPM2.1.9 v. IPM3.0).

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for haze should reflect a weight-of-evidence approach, with consideration of monitoring based information.

Additional Modeling: Two additional modeling analyses were considered: (1) the primary modeling redone with different baseline values, and (2) modeling by the State of Minnesota which looked at different receptor locations in the northern Class I areas (MPCA, 2008). Each of these analyses is described below.

First, the primary modeling analysis (Base M) was revised using an alternative baseline value. Specifically, the data for the period 2000-2005 were used to calculate the baseline, given that the Base M modeling reflects a 2005 base year. The results of this alternative analysis (see Table 18) are generally consistent with the primary modeling (see Table 16).

Second, Minnesota's modeling reflects a 2002 base year and much of the data developed by LADCO for its modeling. (Note, Minnesota conducted modeling for LADCO's domain at 36 km, and for a statewide domain at 12 km.) The purpose of the 12 km modeling was to address local scale impacts on the northern Class I areas at several locations, not just the location of the IMPROVE monitor. Results for the Boundary Waters on the 20% worst days range from 18.3 – 19.0 dv, with an average value of 18.7 dv, which is consistent with Minnesota's 36 km modeling results at the IMPROVE monitor. This variability in visibility levels should be kept in mind when reviewing the values presented in Tables 15, 16, and 18, which reflect results at the IMPROVE monitor locations.

Table 18. Haze Results - Round 5.1 (Based on 2000-2005)						
Worst 20%			**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	20.10	18.12	18.63	18.51	18.12	18.09
VOYA2	19.62	17.86	18.27	18.15	17.70	17.72
SENE1	24.77	21.94	23.44	23.39	**22.94**	**22.77**
ISLE1	21.95	19.71	20.84	20.76	**20.41**	**20.44**
ISLE9	21.95	19.71	20.65	20.55	**20.15**	**20.13**
HEGL1	27.45	23.67	25.30	25.27	**24.79**	**24.73**
MING1	28.92	24.86	25.88	25.68	24.74	24.83
CACR1	27.05	23.44	23.88	23.78	22.92	22.86
UPBU1	26.97	23.36	23.92	23.85	23.14	23.09
MACA1	31.76	26.93	27.42	27.32	26.39	26.44
DOSO1	29.36	24.92	24.20	24.11	23.19	23.23
SHEN1	29.45	25.23	25.06	24.94	23.98	24.01
JARI1	29.40	25.13	25.32	25.17	24.22	24.28
BRIG1	29.12	25.14	25.84	25.77	**25.26**	**25.26**
LYBR1	24.71	21.69	22.22	22.06	21.36	21.36
ACAD1	22.91	20.47	21.72	21.72	**21.49**	**21.49**
Best 20%			**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	6.40	6.40	6.20	6.17	6.13	6.10
VOYA2	7.05	7.05	6.82	6.78	6.71	6.71
SENE1	7.20	7.20	7.60	7.61	7.73	7.80
ISLE1	6.80	6.80	6.67	6.64	6.65	6.66
ISLE9	6.80	6.80	6.62	6.61	6.57	6.55
HEGL1	13.04	13.04	12.71	12.51	11.85	11.82
MING1	14.68	14.68	14.07	13.89	13.28	13.29
CACR1	11.62	11.62	11.24	11.20	10.86	10.86
UPBU1	11.99	11.99	11.41	11.36	11.01	11.02
MACA1	16.64	16.64	15.88	15.82	15.37	15.38
DOSO1	12.24	12.24	11.21	11.19	10.96	10.97
SHEN1	10.85	10.85	10.04	10.02	9.82	9.83
JARI1	14.35	14.35	13.51	13.51	13.27	13.27
BRIG1	14.36	14.36	14.17	14.10	13.94	13.94
LYBR1	6.21	6.21	6.11	6.09	6.01	6.01
ACAD1	8.57	8.57	8.67	8.66	8.62	8.62

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., application of thermodynamic equilibrium models) is presented in Section 3. The key findings from this modeling are that $PM_{2.5}$ mass is sensitive to reductions in sulfate, nitric acid, and ammonia concentrations. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases and visibility improves. Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

As discussed in Section 2, thermodynamic equilibrium modeling based on data collected at Seney indicates that $PM_{2.5}$ there is most sensitive to reductions in sulfate, but also responsive to reductions in nitric acid (Blanchard, 2004). An analysis using data from the Midwest ammonia monitoring network for a site in Minnesota (i.e., Great River Bluffs, which is the closest ammonia monitoring site to the northern Class I areas) suggested that reductions in sulfate, nitric acid, and ammonia concentrations will lower $PM_{2.5}$ concentrations and improve visibility levels in the northern Class I areas.

Trajectory analyses for the 20% worst visibility days for the four northern Class I areas are provided in Figure 75. (Note, this figure is similar to Figure 34, but the trajectory results for each Class I area are displayed separately here.) The orange areas are where the air is most likely to come from, and the green areas are where the air is least likely to come from. Darker shading represents higher frequency. As can be seen, bad air days are generally associated with transport from regions located to the south, and good air days with transport from Canada.

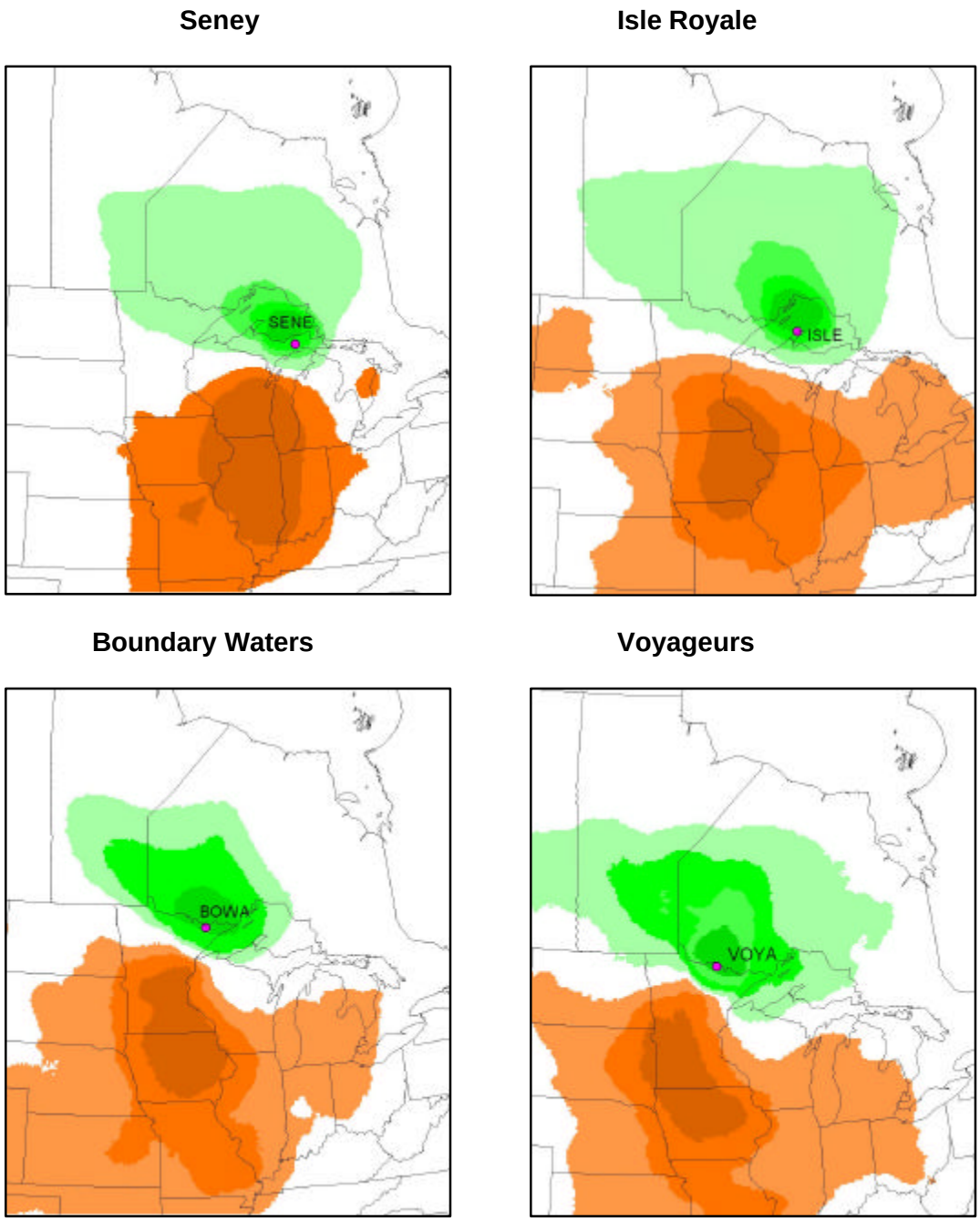


Figure 75. Trajectory analysis results for northern Class I areas on 20% worst visibility days

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007b). Specifically, the CAMx model was applied to provide source contribution information. Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 76) and 6 source se ctors (EGU point, non-EGU point, on-road, off-road, area, and ammonia sources) at visibility/haze monitoring sites in the eastern U.S.

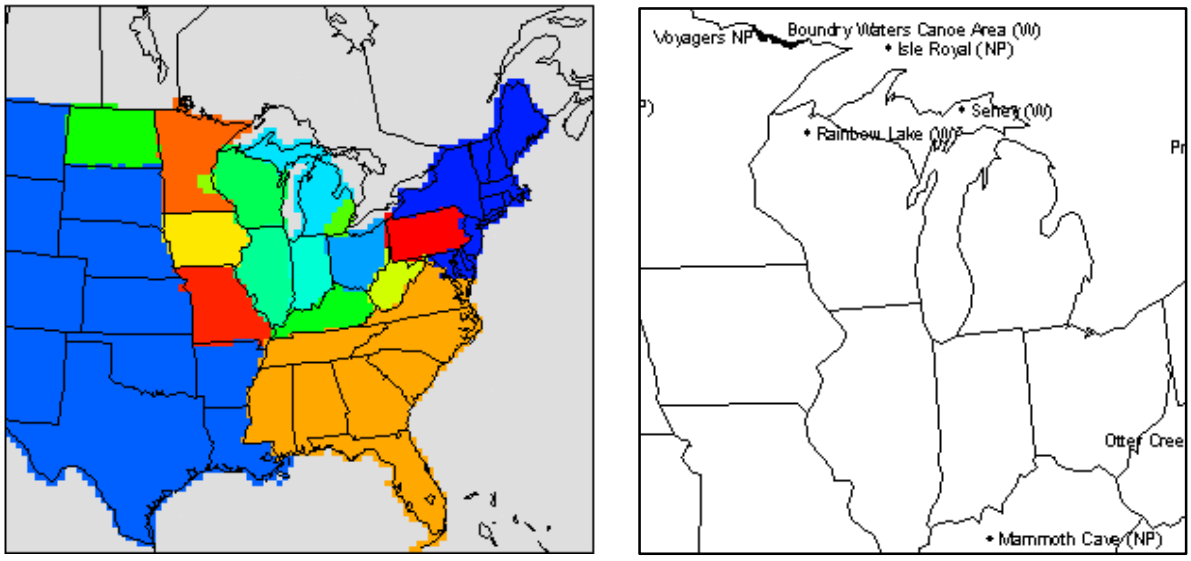


Figure 76. Source regions (left) and key monitoring sites (right) for haze modeling analysis

Modeling results for 2018 (Base K and Base M) are provided in Appendix IV for several key monitoring sites (Class I areas). For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of absolute modeled values.

The sector-level results (see, for example, Figure 77) show that EGU sulfate, non-EGU-sulfate, and ammonia emissions generally have the largest contributions at the key monitor locations. The source group contributions vary by receptor location due to emissions inventory differences.

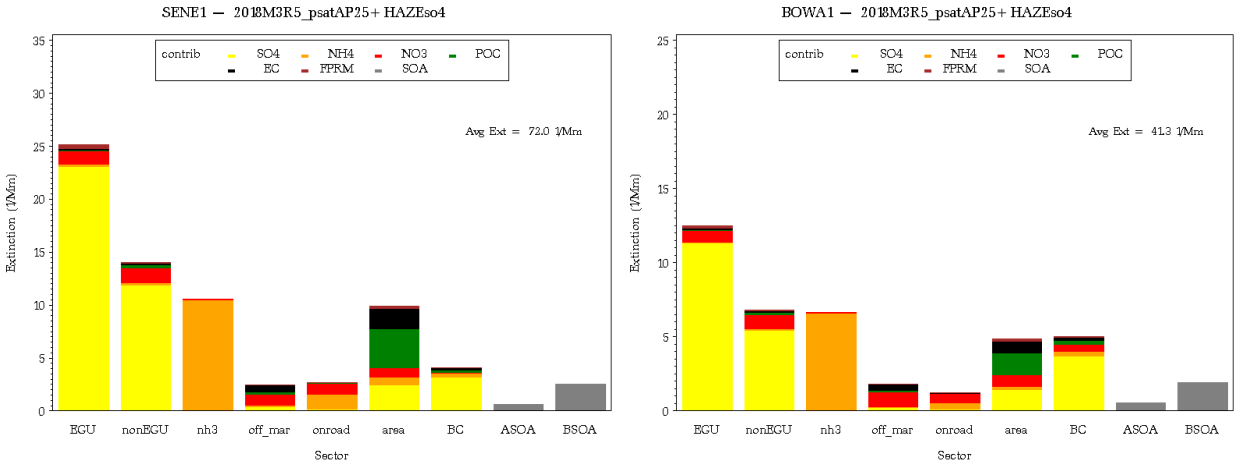


Figure 77. Source-sector results for Seney (left) and Boundary Waters (right) – 2018 (Base M)

The source region results (see, for example, Figure 78) show that emissions from a number of nearby states contribute to regional haze levels.

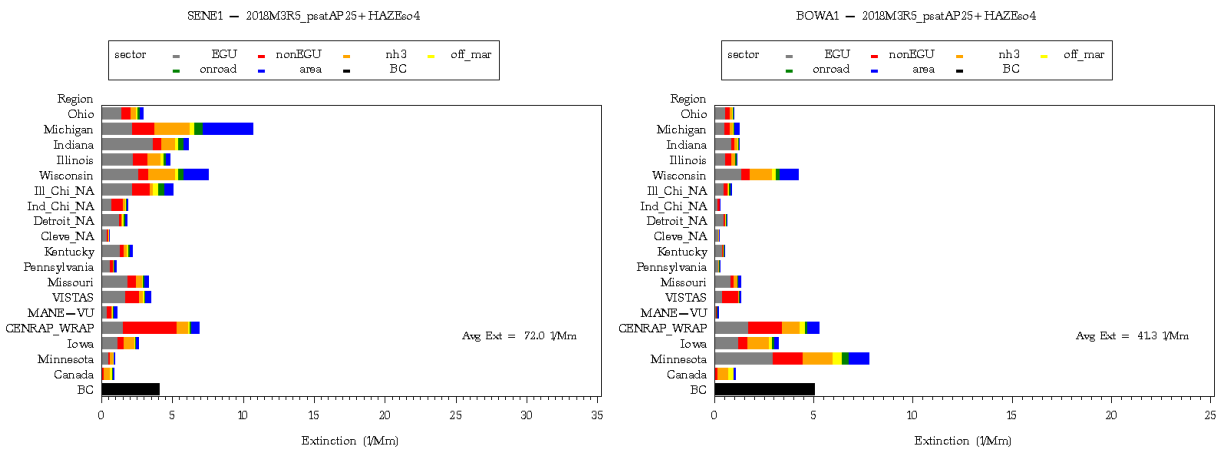


Figure 78. Source-region results for Seney (left) and Boundary Waters (right) – 2018 (Base M)

Table 19 provides a summary of the estimated state-level culpabilities based on the LADCO back trajectory analyses and the PSAT analyses for 2018.

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year visibility levels. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to improve visibility levels in the northern Class I areas.
- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018, including those in northern Michigan and some in the northeastern U.S.
- Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018.

Table 19. State Culpabilities Based on PSAT Modeling and Trajectory Analyses

	Boundary Waters						Seney			
	LADCO - Round 4 PSAT	**LADCO - Round 5 PSAT**	**MPCA-PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**		**LADCO - Round 4 PSAT**	**LADCO - Round 5 PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**
Michigan	3.4%	4.8%	3.0%	1.9%	0.7%		13.8%	18.1%		14.7%
Minnesota	30.5%	23.5%	28.0%	30.6%	37.6%		4.8%	1.6%		3.8%
Wisconsin	10.4%	10.9%	10.0%	6.4%	10.6%		12.6%	10.9%		8.4%
Illinois	5.2%	5.1%	6.0%	3.5%	2.7%		13.0%	14.3%		7.4%
Indiana	2.9%	3.9%	3.0%	1.8%	1.2%		9.6%	11.6%		2.2%
Iowa	7.6%	8.3%	8.0%	2.5%	7.4%		6.2%	3.8%		5.7%
Missouri	5.2%	3.4%	6.0%	2.1%	3.3%		6.5%	4.8%		3.2%
N. Dakota	5.7%	1.1%	6.0%	4.6%	5.9%		1.5%	0.1%		0.6%
Canada	1.9%	2.7%	3.0%	12.5%	15.1%		2.1%	1.2%		11.1%
CENRAP-WRAP	10.9%	13.5%		4.2%	10.1%		13.1%	10.0%		7.0%
	83.6%	**77.2%**	**73.0%**	**70.2%**	**94.6%**		**83.3%**	**76.4%**		**64.1%**
	Voyageurs						**Isle Royale**			
	LADCO - Round 4 PSAT	**LADCO - Round 5 PSAT**	**MPCA-PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**		**LADCO - Round 4 PSAT**	**LADCO - Round 5 PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**
Michigan	2.0%	4.9%	2.0%	1.0%	1.6%		12.7%	13.4%		
Minnesota	35.0%	20.2%	31.0%	31.5%	36.9%		14.1%	9.5%		
Wisconsin	6.3%	7.9%	6.0%	3.7%	9.7%		16.3%	14.7%		
Illinois	3.0%	7.1%	3.0%	1.8%	1.2%		7.0%	8.7%		
Indiana	1.6%	4.6%	2.0%	0.8%			5.6%	5.2%		
Iowa	7.4%	7.1%	7.0%	2.4%	10.2%		6.9%	8.3%		
Missouri	4.3%	4.0%	4.0%	1.6%	0.3%		3.9%	4.6%		
N. Dakota	10.3%	1.7%	13.0%	6.1%	7.1%		3.6%	0.3%		
Canada	2.7%	3.3%	5.0%	17.2%	13.3%		2.2%	1.7%		
CENRAP-WRAP	10.2%	13.7%		6.1%	16.5%		12.5%	12.6%		
	82.7%	**74.5%**	**73.0%**	**72.2%**	**96.8%**		**84.9%**	**79.0%**		

Section 6. Summary

To support the development of SIPs for ozone, $PM_{2.5}$, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin, technical analyses were conducted by LADCO, its member states, and various contractors. The analyses include preparation of regional emissions inventories and meteorological modeling data for two base years, evaluation and application of regional chemical transport models, and review of ambient monitoring data.

Analyses of monitoring data were conducted to produce a conceptual model, which is a qualitative summary of the physical, chemical, and meteorological processes that control the formation and distribution of pollutants in a given region. Key findings of the analyses include:

Ozone

- Current monitoring data show about 20 sites in violation of the 8-hour ozone standard of 85 ppb. Historical ozone data show a steady downward trend over the past 15 years, especially since 2001-2003, due likely to federal and state emission control programs.

- Ozone concentrations are strongly influenced by meteorological conditions, with more high ozone days and higher ozone levels during summers with above normal temperatures.

- Inter- and intra-regional transport of ozone and ozone precursors affects many portions of the five states, and is the principal cause of nonattainment in some areas far from population or industrial centers

$PM_{2.5}$

- Current monitoring data show 30 sites in violation of the annual $PM_{2.5}$ standard of 15 ug/m^3. Nonattainment sites are characterized by an elevated regional background (about 12 – 14 ug/m^3) and a significant local (urban) increment (about 2 – 3 ug/m^3). Historical $PM_{2.5}$ data show a slight downward trend since deployment of the $PM_{2.5}$ monitoring network in 1999.

- $PM_{2.5}$ concentrations are also influenced by meteorology, but the relationship is more complex and less well understood compared to ozone.

- On an annual average basis, $PM_{2.5}$ chemical composition consists of mostly sulfate, nitrate, and organic carbon in similar proportions.

Haze

- Current monitoring data show visibility levels in the Class I areas in northern Michigan are on the order of 22 – 24 deciviews. The goal of EPA's visibility program is to achieve natural conditions, which is on the order of 12 deciviews for these Class I areas, by the year 2064.

- Visibility impairment is dominated by sulfate and nitrate.

Air quality models were applied to support the regional planning efforts. Two base years were used in the modeling analyses: 2002 and 2005. EPA's modeling guidance recommends using

2002 as the baseline inventory year, but also allows for use of an alternative baseline inventory year, especially a more recent year. Initially, LADCO conducted modeling with a 2002 base year (i.e., Base K modeling, which was completed in 2006). A decision was subsequently made to conduct modeling with a 2005 base year (i.e., Base M, which was completed in 2007). Statistical analyses showed that 2002 and 2005 both had above normal ozone-conducive conditions, although 2002 was more severe compared to 2005. Examination of multiple base years provides for a more complete technical assessment. Both sets of model runs are discussed in this document.

Basecase modeling was conducted to evaluate model performance (i.e., assess the model's ability to reproduce the observed concentrations). This exercise was intended to assess whether, and to degree, confidence in the model is warranted (and to assess whether model improvements are necessary). Model performance for ozone and $PM_{2.5}$ was generally acceptable and can be characterized as follows:

Ozone

- Good agreement between modeled and monitored concentration for higher concentration levels (> 60 ppb) – i.e., bias within 30%

- Regional modeled concentrations appear to be underestimated in the 2002 base year, but show better agreement (with monitored data) in the 2005 base year due to model and inventory improvements.

- Day-to-day and hour-to-hour variation in and spatial patterns of modeled concentrations are consistent with monitored data

- Model accurately simulates the change in monitored ozone concentrations due to reductions in precursor emissions.

$PM_{2.5}$

- Good agreement in the magnitude of fine particle mass, but some species are overestimated and some are underestimated
    - Sulfates: good agreement in the 2002 base year, but underestimated in the summer in the 2005 base year due probably to meteorological factors
    - Nitrates: slightly overestimated in the winter in the 2002 base year, but good agreement in the 2005 base year as a result of model and inventory improvements
    - Organic Carbon: grossly underestimated in the 2002 and 2005 base years due likely to missing primary organic carbon emissions

- Temporal variation and spatial patterns of modeled concentrations are consistent with monitored data

Future year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Traditionally, attainment demonstrations involved a "bright line" test in which a single modeled value (based on EPA guidance) was compared to the ambient standard. To provide a more robust assessment of expected future year air quality, other information was considered. Furthermore, according to EPA's modeling guidance, if the future year modeled values are "close" to the

standard (i.e., 82 – 87 ppb for ozone and 14.5 – 15.5 ug/m^3 for $PM_{2.5}$), then the results of the primary modeling should be reviewed along with the supplemental information in a "weight of evidence" (WOE) assessment of whether each area is likely to achieve timely attainment. Key findings of the WOE determination include:

- Existing controls are expected to produce significant improvement in ozone and $PM_{2.5}$ concentrations and visibility levels.

- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).

- Most sites are expected to meet the current 8-hour standard by the applicable attainment date, except for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.

- Most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.

  The regional modeling for $PM_{2.5}$ does not reflect air quality benefits expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$.

- These findings of residual nonattainment for ozone and $PM_{2.5}$ are supported by current (2005 – 2007) monitoring data which show significant nonattainment in the region (e.g., peak ozone design values on the order of 90 – 93 ppb, and peak $PM_{2.5}$ design values on the order of 16 - 17 ug/m^3). It is unlikely that sufficient emission reductions will occur in the next few of years to provide for attainment at all sites.

- Attainment at most sites by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). If either of these conditions is not met, then attainment may be less likely.

- The new $PM_{2.5}$ 24-hour standard and the new lower ozone standard will not be met at several sites, even by 2018, with existing controls.

- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018 based on existing controls, including those in northern Michigan and some in the northeastern U.S. Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018.

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APPENDIX I

Ozone and $PM_{2.5}$ Modeling Results

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2008 - OTB		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	
Lake Michigan Area														***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.968	**82.0**	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.966	77.6	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.963	79.6	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.960	80.0	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.957	81.3	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.959	**84.4**	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.954	78.9	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.956	**84.8**	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.971	75.4	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.971	77.0	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.964	74.2	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.967	75.7	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.951	**85.6**	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.950	77.9	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.951	80.8	Muskegon
Indianapolis Area														***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.944	78.0	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.948	73.9	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.951	74.8	Fort B. Harrison
Detroit Area														***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.962	**82.7**	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.982	**82.5**	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.956	79.0	Port Huron
Cleveland Area														***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.954	**84.9**	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.954	75.7	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.959	**82.8**	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.948	79.3	
Cincinnati Area														***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.945	77.8	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.965	81.7	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.954	**83.6**	Lebanon
Columbus Area														***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.946	75.4	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.954	**82.4**	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.958	77.0	Franklin
St. Louis Area														***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.954	**82.4**	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.958	**83.3**	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.966	79.5	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.956	78.7	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.962	79.8	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.967	**84.5**	Maryland Heights (MO)

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2009 - OTB			2009 - Will Do		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	Round 4	RRF	Round 5	
Lake Michigan Area																	***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.972	**82.3**	**92.0**	0.971	**82.2**	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.965	77.5	**84.9**	0.964	77.4	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.965	79.8	**84.9**	0.964	79.7	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.961	80.1	**85.4**	0.960	80.0	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.951	80.8	78.9	0.949	80.7	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.955	**84.0**	**88.9**	0.953	**83.9**	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.945	78.1	81.0	0.943	78.0	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.946	**83.9**	81.8	0.945	**83.8**	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.971	75.4	**86.6**	0.970	75.3	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.971	77.0		0.970	77.0	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.960	73.9	**86.5**	0.959	73.8	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.965	75.6	82.8	0.964	75.5	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.948	**85.3**	**83.4**	0.947	**85.2**	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.940	77.1	77.6	0.939	77.0	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.947	80.5	81.5	0.945	80.3	Muskegon
Indianapolis Area																	***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.945	78.1	**83.7**	0.946	78.2	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.947	73.9	**83.8**	0.948	73.9	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.955	75.1	**83.7**	0.956	75.2	Fort B. Harrison
Detroit Area																	***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.947	81.4	**85.3**	0.947	81.4	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.968	81.3	**83.3**	0.969	81.4	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.937	77.5	79.1	0.938	77.5	Port Huron
Cleveland Area																	***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.937	**83.4**	**82.7**	0.941	**83.7**	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.942	74.7	**88.8**	0.945	75.0	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.949	81.9	**82.8**	0.954	**82.4**	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.934	78.1	81.4	0.935	78.2	
Cincinnati Area																	***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.941	77.5	**83.5**	0.942	77.6	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.967	81.9	**84.7**	0.968	82.0	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.947	**83.0**	79.0	0.948	**83.1**	Lebanon
Columbus Area																	***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.941	75.0	78.4	0.942	75.0	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.947	81.8	**82.6**	0.948	81.8	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.945	75.9	76.5	0.948	76.2	Franklin
St. Louis Area																	***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.938	81.0	**85.2**	0.932	80.5	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.942	**82.0**	**82.2**	0.939	81.7	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.956	78.7	81.9	0.954	78.5	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.938	77.2	77.4	0.937	77.1	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.955	79.3	**83.4**	0.955	79.3	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.955	**83.4**		0.954	**83.3**	Maryland Heights (MO)

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2012 - OTB			2018 - OTB		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	Round 4	RRF	Round 5	
Lake Michigan Area																	***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.956	80.9	**90.3**	0.900	76.2	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.947	76.1	**82.9**	0.886	71.2	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.944	78.0	**82.3**	0.880	72.7	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.939	78.3	**82.9**	0.870	72.5	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.925	78.6	76.3	0.853	72.5	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.930	81.8	**86.4**	0.857	75.4	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.918	75.9	79.1	0.845	69.9	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.919	81.5	79.3	0.843	74.7	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.960	74.6	**86.3**	0.922	71.6	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.960	76.2		0.922	73.1	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.942	72.5	**85.4**	0.884	68.1	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.951	74.5	**82.0**	0.904	70.8	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.920	**82.8**	81.0	0.846	76.1	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.909	74.5	75.5	0.838	68.7	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.918	78.0	79.4	0.846	71.9	Muskegon
Indianapolis Area																	***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.914	75.6	**82.0**	0.831	68.7	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.916	71.4	**82.1**	0.835	65.1	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.931	73.2	**82.4**	0.879	69.1	Fort B. Harrison
Detroit Area																	***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.932	80.2	**83.5**	0.885	76.1	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.961	80.7	81.9	0.924	77.6	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.913	75.5	77.0	0.858	70.9	Port Huron
Cleveland Area																	***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.910	81.0	80.2	0.844	75.1	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.916	72.7	**86.2**	0.848	67.3	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.932	80.5	80.6	0.883	76.2	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.903	75.6	78.5	0.821	68.7	Akron
Cincinnati Area																	***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.910	74.9	81.1	0.830	68.3	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.948	80.3	**82.9**	0.881	74.6	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.921	80.7	77.0	0.846	74.2	Lebanon
Columbus Area																	***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.911	72.6	76.5	0.832	66.3	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.922	79.6	80.2	0.845	73.0	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.923	74.1	74.7	0.859	69.0	Franklin
St. Louis Area																	***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.911	78.6	**84.0**	0.868	74.9	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.919	80.0	80.4	0.876	76.2	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.937	77.1	80.6	0.897	73.9	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.918	75.6	75.8	0.874	72.0	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.939	77.9	**82.5**	0.896	74.4	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.936	81.7		0.894	78.1	Maryland Heights (MO)

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2009 Modeling Results		
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	**14.1**	**14.8**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	**14.4**	**15.8**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.9	**14.5**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.8	**14.5**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.7	**14.5**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	**14.2**	**14.8**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.4**	**15.3**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**15.1**	**16.0**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	**14.1**	**14.9**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.8	**15.5**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	12.4	13.8	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		13.0		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.8	**14.5**	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		13.4		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	13.4	**14.8**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	13.0	**14.5**	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	**14.2**	**15.8**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	13.1	**14.1**	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.8**	**17.7**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	13.1	**15.1**	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	13.5	**14.2**	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	13.1	13.5	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	13.5	**14.4**	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**15.2**	**16.1**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	**14.4**	**14.6**	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**15.0**	**15.3**	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	**14.0**	**14.1**	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.9	**14.6**	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	12.7	**14.1**	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	11.7	**14.0**	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	**14.5**	**15.5**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.8	13.6	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	**14.0**	**14.6**	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.9	13.6	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	13.4	**14.2**	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.7**	**15.2**	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.8	**16.3**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.5	**15.5**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.8	**14.2**	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	13.2	13.7	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	12.1	**15.4**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	**14.0**	**15.0**	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	12.6	13.6	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	13.0	**14.4**	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	12.3	13.6	Akron - W. Exchange

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2012 Modeling Results		
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	**14.0**	**14.6**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	**14.2**	**15.5**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.8	**14.3**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.7	**14.3**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.6	**14.3**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	**14.0**	**14.6**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.3**	**15.1**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**14.9**	**15.8**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	13.9	**14.7**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.7	**15.0**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	12.2	13.5	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		12.8		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.6	**14.2**	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		13.2		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	13.1	**14.9**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	12.8	**14.1**	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	13.9	**15.3**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	12.8	13.7	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.5**	**17.1**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	12.8	**14.7**	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	13.2	13.7	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	12.9	12.9	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	13.2	13.8	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**14.8**	**15.4**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	**14.0**	**14.0**	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**14.6**	**14.7**	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	13.6	13.5	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.6	**14.0**	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	12.4	13.5	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	11.4	13.4	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	**14.3**	**14.8**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.6	13.0	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	13.8	**14.0**	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.7	13.0	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	13.2	13.6	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.4**	**14.6**	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.5	**15.9**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.2	**15.0**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.5	13.7	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	12.9	13.2	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	11.9	**14.8**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	13.6	**14.3**	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	12.3	13.0	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	12.7	13.6	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	12.0	13.0	Akron - W. Exchange

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2018 Modeling Results			
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5 OTB	Round 5 Will Do	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	13.9	13.8	**14.4**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	13.9	13.8	**15.0**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.7	13.5	**14.1**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.6	13.4	**14.1**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.4	13.3	**14.1**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	13.9	13.8	**14.4**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.2**	**14.0**	**14.9**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**14.3**	**14.2**	**15.5**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	13.4	13.3	**14.5**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.4	13.4	**14.4**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	11.8	11.9	13.0	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		12.4	12.4		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.0	12.1	13.7	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		12.6	12.7		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	12.6	12.6	**14.0**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	12.4	12.4	13.3	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	13.5	13.5	**14.4**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	12.5	12.5	13.0	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.1**	**15.1**	**16.1**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	12.5	12.5	13.9	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	12.8	12.8	13.1	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	12.5	12.6	12.2	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	12.7	12.9	12.9	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**14.3**	**14.5**	**14.4**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	13.5	13.7	13.1	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**14.1**	**14.2**	13.7	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	13.1	13.3	12.6	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.0	12.1	13.0	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	11.9	11.9	12.5	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	10.9	11.0	12.5	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	13.8	13.9	**14.0**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.2	12.3	12.3	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	13.4	13.4	13.2	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.3	12.4	12.2	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	12.8	12.8	12.8	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.0**	**14.1**	13.8	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.7	12.7	**16.2**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.4	13.4	**15.3**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.3	12.3	13.2	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	12.4	12.5	12.3	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	11.6	11.6	**14.2**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	13.3	13.3	13.6	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	11.9	12.0	12.2	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	12.3	12.3	12.9	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	11.5	11.6	12.2	Akron - W. Exchange

24-Hour $PM_{2.5}$			98th Percentile (24-hour)					Design Values			Base Year	Round 5 Modeling Results			
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average w/ 2007	2009	2012	2018	Key Site
Chicago - Washington HS	Cook	170310022	37.7	32.5	45.7	27.0	35.7	38.6	35.1	36.1	36.6	36	36	35	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	37.3	38.8	48.3	31.6	39.4	41.5	39.6	39.8	40.3	36	36	36	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	36.4	33.1	46.5	27.7	38.9	38.7	35.8	37.7	37.4	32	32	31	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	32.6	39.7	45.1	29.0	37.2	39.1	37.9	37.1	38.1	35	35	34	Chicago - Lawndale
McCook	Cook	170311016									43.0	39	39	38	McCook
Blue Island	Cook	170312001	39.6	38.5	43.8	28.1	35.1	40.6	36.8	35.7	37.7	34	34	33	Blue Island
Schiller Park	Cook	170313103		40.7	50.3	30.0	36.6	45.5	40.3	39.0	41.6	39	39	39	Schiller Park
Summit	Cook	170313301	38.4	42.4	49.1	27.4	36.7	43.3	39.6	37.7	40.2	38	38	37	Summit
Maywood	Cook	170316005	38.5	42.5	44.6	29.2	36.9	41.9	38.8	36.9	39.2	38	38	37	Maywood
Granite City	Madison	171191007	40.8	35.4	44.1	36.3	36.0	40.1	38.6	38.8	39.2	33	33	32	Granite City
E. St. Louis	St. Clair	171630010	32.6	30.2	39.6	29.2	33.1	34.1	33.0	34.0	33.7	28	28	28	E. St. Louis
Jeffersonville	Clark	180190005		28.4	45.5	35.9	43.3	37.0	36.6	41.6	38.4	29	31	31	Jeffersonville
Jasper	Dubois	180372001	39.5	30.0	41.2	31.6	39.5	36.9	34.3	37.4	36.2	28	29	28	Jasper
Gary - IITRI	Lake	180890022									39.0	34	34	35	Gary - IITRI
Gary - Burr School	Lake	180890026									39.0	33	34	32	Gary - Burr School
Gary	Lake	180890031			38.7	27.1	36.2	38.7	32.9	34.0	35.2	24	24	27	Gary
Indy-West Street	Marion	180970043									38.0	33	33	33	Indy-West Street
Indy-English Avenue	Marion	180970066									38.0	32	32	32	Indy-English Avenue
Indy-Washington Park	Marion	180970078	39.3	31.0	42.5	31.7	37.6	37.6	35.1	37.3	36.6	31	31	32	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	36.2	31.9	45.7	34.8	38.4	37.9	37.5	39.6	38.3	31	31	31	Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	36.7	31.3	40.3	33.5	37.2	36.1	35.0	37.0	36.0	28	28	29	Indy- Michigan Street
Luna Pier	Monroe	261150005	34.7	35.0	49.3	32.6	32.2	39.7	39.0	38.0	38.9	32	32	31	Luna Pier
Oak Park	Oakland	261250001	36.6	32.5	52.2	33.0	35.3	40.4	39.2	40.2	39.9	36	36	35	Oak Park
Port Huron	St. Clair	261470005	37.2	32.2	47.6	37.9	36.3	39.0	39.2	40.6	39.6	34	34	33	Port Huron
Ypsilanti	Washtenaw	261610008	38.8	31.5	52.1	31.3	34.5	40.8	38.3	39.3	39.5	35	35	34	Ypsilanti
Allen Park	Wayne	261630001	40.5	36.9	43.0	34.1	35.9	40.1	38.0	37.7	38.6	35	34	33	Allen Park
Southwest HS	Wayne	261630015	33.6	36.0	49.7	36.2	34.0	39.8	40.6	40.0	40.1	35	35	33	Southwest HS
Linwood	Wayne	261630016	46.2	38.3	51.8	36.9	34.8	45.4	42.3	41.2	43.0	39	39	38	Linwood
E 7 Mile	Wayne	261630019	37.1	35.0	52.3	36.2	33.0	41.5	41.2	40.5	41.0	38	38	37	E 7 Mile
Dearborn	Wayne	261630033	42.8	39.4	50.2	43.1	36.6	44.1	44.2	43.3	43.9	40	40	39	Dearborn
Wyandotte	Wayne	261630036	34.8	32.3	46.7	33.2	28.6	37.9	37.4	36.2	37.2	35	35	34	Wyandotte
Newberry	Wayne	261630038		36.8	57.5	28.6	33.4		39.1	39.8	42.7	38	37	36	Newberry
FIA	Wayne	261630039			43.9	32.4	34.8			37.0	39.7	33	33	31	FIA
Middleton	Butler	390170003	38.6	37.2	47.6	30.2	37.1	41.1	38.3	38.3	39.3	28	28	27	Middleton
Fairfield	Butler	390170016	34.8	32.2	43.4	35.2	34.5	36.8	36.9	37.7	37.1	27	28	27	Fairfield
	Butler	390170017	34.6	34.3	44.9			37.9	39.6		40.8	29	29	28	
Cleveland-28th Street	Cuyahoga	390350027	41.3	40.9	35.7	31.5	39.0	39.3	36.0	35.4	36.9	32	32	31	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	47.3	42.5	51.2	36.1	39.7	44.9	47.0	42.3	44.2	36	35	34	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	42.2	36.1	46.2	29.5	37.0	41.5	37.3	37.6	38.8	31	30	29	Cleveland-Broadway
Cleveland-GT Craig	Cuyahoga	390350060	45.5	42.2	49.5	31.0	38.7	45.7	40.9	39.7	42.1	37	37	35	Cleveland-GT Craig
Newburg Hts - Harvard Ave	Cuyahoga	390350065	39.1	36.1	47.9	27.8	39.1	41.0	37.3	38.3	38.9	31	30	30	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	39.2	35.1	45.0	34.0	34.2	39.8	38.0	37.7	38.5	33	32	31	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	37.0	35.5	44.9	34.0	35.5	39.1	38.1	38.1	38.5	31	31	30	Columbus - Ann Street
Cincinnait	Hamilton	390610006			45.0	33.3	34.7			37.7	40.6	27	28	27	Cincinnait
Cincinnati - Seymour	Hamilton	390610014	37.8	42.0	38.5	35.2	38.1	39.4	38.6	37.3	38.4	26	25	24	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	31.9	30.5	45.8	32.8	34.7	36.1	36.4	37.8	36.7	24	24	23	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	33.8	31.9	44.4	34.5	35.9	36.7	36.9	38.3	37.3	28	28	27	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	37.3	31.4	39.9	34.9	34.0	36.2	35.4	36.3	36.0	28	28	27	Sharonville
Norwood	Hamilton	390617001	37.1	34.6	47.1	34.0	33.7	39.6	38.6	38.3	38.8	30	30	29	Norwood
St. Bernard	Hamilton	390618001	35.8	33.9	51.4	36.1	35.4	40.4	40.5	41.0	40.6	30	30	29	St. Bernard
Steubenville	Jefferson	390810016	39.6	43.8	43.8	32.1	43.5	42.4	39.9	39.8	40.7	29	28	28	Steubenville
Mingo Junction	Jefferson	390811001	40.9	51.5	44.2	32.9	35.4	45.5	42.9	37.5	42.0	30	30	30	Mingo Junction
Dayton	Montgomery	391130032	42.7	32.5	45.0	30.3	36.9	40.1	35.9	37.4	37.8	30	30	30	Dayton
Canton - Dueber	Stark	391510017	34.2	36.3	47.6	32.2	33.4	39.4	38.7	37.7	38.6	28	28	27	Canton - Dueber
Akron - Brittain	Summit	391530017	36.9	36.9	45.2	31.5	33.3	39.7	37.9	36.7	38.1	30	30	29	Akron - Brittain
Green Bay - Est High	Brown	550090005	33.5	32.3	41.5	36.9	37.1	35.8	36.9	38.5	37.1	35	34	32	Green Bay - Est High
Madison	Dane	550250047	32.0	31.9	40.1	33.4	44.3	34.7	35.1	39.3	36.4	32	31	29	Madison
Milwaukee-Health Center	Milwaukee	550790010	33.2	38.4	38.7	40.7	40.6	36.8	39.3	40.0	38.7	35	34	33	Milwaukee-Health Center
Milwaukee-SER Hdqs	Milwaukee	550790026	29.6	28.7	41.5	42.6	39.8	33.3	37.6	41.3	37.4	34	34	33	Milwaukee-SER Hdqs
Milwaukee-Virginia FS	Milwaukee	550790043	39.2	41.4	37.1	44.0	38	39.2	40.8	39.7	39.9	36	36	36	Milwaukee-Virginia FS
Milwaukee- Fire Dept Hdqs	Milwaukee	550790099	33.7	38.9	37.1	38.3	40.7	36.6	38.1	38.7	37.8	33	32	32	Milwaukee- Fire Dept Hdqs
Waukesha	Waukesha	551330027	29.1	38.4	41.1	28.2	33.8	36.2	35.9	34.4	35.5	31	31	29	Waukesha

PM2.5 RRFs by Species and Season (2009)						
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
1703100521	IL	Cook	winter	so4	0.1772	0.9342
1703100521	IL	Cook	winter	no3	0.3099	1.0128
1703100521	IL	Cook	winter	ocm	0.2147	0.9942
1703100521	IL	Cook	winter	ec	0.0372	0.888
1703100521	IL	Cook	winter	soil	0.0242	1.1674
1703100521	IL	Cook	winter	nh4	0.1421	0.97
1703100521	IL	Cook	winter	pbw	0.0947	0.9678
1703100521	IL	Cook	spring	so4	0.32	0.8018
1703100521	IL	Cook	spring	no3	0.0609	0.9385
1703100521	IL	Cook	spring	ocm	0.2742	1.0629
1703100521	IL	Cook	spring	ec	0.0501	0.8712
1703100521	IL	Cook	spring	soil	0.0505	1.1796
1703100521	IL	Cook	spring	nh4	0.1203	0.8619
1703100521	IL	Cook	spring	pbw	0.0984	0.8492
1703100521	IL	Cook	summer	so4	0.3089	0.725
1703100521	IL	Cook	summer	no3	0	1.0124
1703100521	IL	Cook	summer	ocm	0.1599	1.069
1703100521	IL	Cook	summer	ec	0.0351	0.8683
1703100521	IL	Cook	summer	soil	0.0318	1.204
1703100521	IL	Cook	summer	nh4	0.0932	0.7354
1703100521	IL	Cook	summer	pbw	0.094	0.7217
1703100521	IL	Cook	fall	so4	0.1872	0.9151
1703100521	IL	Cook	fall	no3	0.1628	0.9408
1703100521	IL	Cook	fall	ocm	0.2389	1.0091
1703100521	IL	Cook	fall	ec	0.0403	0.8623
1703100521	IL	Cook	fall	soil	0.0284	1.1443
1703100521	IL	Cook	fall	nh4	0.1062	0.9247
1703100521	IL	Cook	fall	pbw	0.0614	0.9233
1711910071	IL	Madison	winter	so4	0.213	0.9195
1711910071	IL	Madison	winter	no3	0.2705	1.0306
1711910071	IL	Madison	winter	ocm	0.2093	0.9289
1711910071	IL	Madison	winter	ec	0.0434	0.9083
1711910071	IL	Madison	winter	soil	0.0306	1.1782
1711910071	IL	Madison	winter	nh4	0.1528	0.9513
1711910071	IL	Madison	winter	pbw	0.0804	0.9243
1711910071	IL	Madison	spring	so4	0.3194	0.7717
1711910071	IL	Madison	spring	no3	0.0189	0.8611
1711910071	IL	Madison	spring	ocm	0.2455	1.1103
1711910071	IL	Madison	spring	ec	0.0564	1.0046
1711910071	IL	Madison	spring	soil	0.0459	1.2252
1711910071	IL	Madison	spring	nh4	0.1121	0.7894
1711910071	IL	Madison	spring	pbw	0.1085	0.7783
1711910071	IL	Madison	summer	so4	0.313	0.705
1711910071	IL	Madison	summer	no3	0	0.884
1711910071	IL	Madison	summer	ocm	0.153	1.1546
1711910071	IL	Madison	summer	ec	0.0345	1.0513
1711910071	IL	Madison	summer	soil	0.0302	1.2532
1711910071	IL	Madison	summer	nh4	0.102	0.7409
1711910071	IL	Madison	summer	pbw	0.1096	0.7133
1711910071	IL	Madison	fall	so4	0.2058	0.9037
1711910071	IL	Madison	fall	no3	0.1308	0.9426
1711910071	IL	Madison	fall	ocm	0.259	1.0233
1711910071	IL	Madison	fall	ec	0.0563	0.9248
1711910071	IL	Madison	fall	soil	0.0549	1.1412
1711910071	IL	Madison	fall	nh4	0.1073	0.9185
1711910071	IL	Madison	fall	pbw	0.0655	0.918

Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
1803720011	IN	Dubois	winter	so4	0.2669	0.8833
1803720011	IN	Dubois	winter	no3	0.2548	0.9526
1803720011	IN	Dubois	winter	ocm	0.1747	0.9374
1803720011	IN	Dubois	winter	ec	0.0313	0.9319
1803720011	IN	Dubois	winter	soil	0.0192	1.1349
1803720011	IN	Dubois	winter	nh4	0.1646	0.9069
1803720011	IN	Dubois	winter	pbw	0.0885	0.9006
1803720011	IN	Dubois	spring	so4	0.4141	0.6808
1803720011	IN	Dubois	spring	no3	0.0022	0.8106
1803720011	IN	Dubois	spring	ocm	0.178	0.9997
1803720011	IN	Dubois	spring	ec	0.0324	0.9083
1803720011	IN	Dubois	spring	soil	0.0218	1.1284
1803720011	IN	Dubois	spring	nh4	0.1432	0.7075
1803720011	IN	Dubois	spring	pbw	0.1556	0.6916
1803720011	IN	Dubois	summer	so4	0.3687	0.644
1803720011	IN	Dubois	summer	no3	0	0.8029
1803720011	IN	Dubois	summer	ocm	0.1174	1.0136
1803720011	IN	Dubois	summer	ec	0.0207	0.913
1803720011	IN	Dubois	summer	soil	0.0213	1.1988
1803720011	IN	Dubois	summer	nh4	0.1168	0.6789
1803720011	IN	Dubois	summer	pbw	0.1246	0.6613
1803720011	IN	Dubois	fall	so4	0.2964	0.8232
1803720011	IN	Dubois	fall	no3	0.138	0.8797
1803720011	IN	Dubois	fall	ocm	0.2116	0.9861
1803720011	IN	Dubois	fall	ec	0.0437	0.9019
1803720011	IN	Dubois	fall	soil	0.03	1.1387
1803720011	IN	Dubois	fall	nh4	0.1449	0.8444
1803720011	IN	Dubois	fall	pbw	0.0941	0.8558
1809700811	IN	Marion	winter	so4	0.2358	0.9192
1809700811	IN	Marion	winter	no3	0.2729	0.9769
1809700811	IN	Marion	winter	ocm	0.1851	0.9546
1809700811	IN	Marion	winter	ec	0.0385	0.8647
1809700811	IN	Marion	winter	soil	0.0239	1.0835
1809700811	IN	Marion	winter	nh4	0.1561	0.9446
1809700811	IN	Marion	winter	pbw	0.0877	0.944
1809700811	IN	Marion	spring	so4	0.3745	0.6868
1809700811	IN	Marion	spring	no3	0.0167	0.8082
1809700811	IN	Marion	spring	ocm	0.2034	0.9881
1809700811	IN	Marion	spring	ec	0.0447	0.8547
1809700811	IN	Marion	spring	soil	0.0376	1.0625
1809700811	IN	Marion	spring	nh4	0.1313	0.7182
1809700811	IN	Marion	spring	pbw	0.1309	0.7056
1809700811	IN	Marion	summer	so4	0.3582	0.6529
1809700811	IN	Marion	summer	no3	0	0.8099
1809700811	IN	Marion	summer	ocm	0.1231	1.0043
1809700811	IN	Marion	summer	ec	0.03	0.8444
1809700811	IN	Marion	summer	soil	0.0253	1.0918
1809700811	IN	Marion	summer	nh4	0.1114	0.6854
1809700811	IN	Marion	summer	pbw	0.1163	0.6674
1809700811	IN	Marion	fall	so4	0.2751	0.8538
1809700811	IN	Marion	fall	no3	0.149	0.9452
1809700811	IN	Marion	fall	ocm	0.223	0.9648
1809700811	IN	Marion	fall	ec	0.0525	0.8412
1809700811	IN	Marion	fall	soil	0.0358	1.089
1809700811	IN	Marion	fall	nh4	0.1378	0.8905
1809700811	IN	Marion	fall	pbw	0.0865	0.8888

Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
2616300331	MI	Wayne	winter	so4	0.1587	0.9206
2616300331	MI	Wayne	winter	no3	0.2394	0.9813
2616300331	MI	Wayne	winter	ocm	0.3193	1.0781
2616300331	MI	Wayne	winter	ec	0.0383	0.9279
2616300331	MI	Wayne	winter	soil	0.0541	1.0206
2616300331	MI	Wayne	winter	nh4	0.1188	0.9518
2616300331	MI	Wayne	winter	pbw	0.0714	0.9566
2616300331	MI	Wayne	spring	so4	0.3383	0.7398
2616300331	MI	Wayne	spring	no3	0.0259	0.8787
2616300331	MI	Wayne	spring	ocm	0.3543	1.0234
2616300331	MI	Wayne	spring	ec	0.0504	0.8671
2616300331	MI	Wayne	spring	soil	0.0915	1.0153
2616300331	MI	Wayne	spring	nh4	0.1191	0.7818
2616300331	MI	Wayne	spring	pbw	0.1126	0.7619
2616300331	MI	Wayne	summer	so4	0.3311	0.6681
2616300331	MI	Wayne	summer	no3	0	0.8431
2616300331	MI	Wayne	summer	ocm	0.2297	1.0029
2616300331	MI	Wayne	summer	ec	0.0362	0.8332
2616300331	MI	Wayne	summer	soil	0.061	1.0177
2616300331	MI	Wayne	summer	nh4	0.1027	0.6974
2616300331	MI	Wayne	summer	pbw	0.1073	0.6754
2616300331	MI	Wayne	fall	so4	0.1898	0.854
2616300331	MI	Wayne	fall	no3	0.1075	0.9367
2616300331	MI	Wayne	fall	ocm	0.3689	1.0607
2616300331	MI	Wayne	fall	ec	0.0546	0.8862
2616300331	MI	Wayne	fall	soil	0.1676	1.0317
2616300331	MI	Wayne	fall	nh4	0.0866	0.8919
2616300331	MI	Wayne	fall	pbw	0.0553	0.8821
3903500381	OH	Cuyahoga	winter	so4	0.2117	0.8993
3903500381	OH	Cuyahoga	winter	no3	0.2665	0.9856
3903500381	OH	Cuyahoga	winter	ocm	0.2048	0.9716
3903500381	OH	Cuyahoga	winter	ec	0.0413	0.8903
3903500381	OH	Cuyahoga	winter	soil	0.0465	1.0959
3903500381	OH	Cuyahoga	winter	nh4	0.1459	0.9416
3903500381	OH	Cuyahoga	winter	pbw	0.0832	0.9541
3903500381	OH	Cuyahoga	spring	so4	0.3334	0.7145
3903500381	OH	Cuyahoga	spring	no3	0.0374	0.8393
3903500381	OH	Cuyahoga	spring	ocm	0.2068	1.0899
3903500381	OH	Cuyahoga	spring	ec	0.052	0.9362
3903500381	OH	Cuyahoga	spring	soil	0.0697	1.0601
3903500381	OH	Cuyahoga	spring	nh4	0.1256	0.7666
3903500381	OH	Cuyahoga	spring	pbw	0.115	0.7761
3903500381	OH	Cuyahoga	summer	so4	0.3241	0.6303
3903500381	OH	Cuyahoga	summer	no3	0	0.89
3903500381	OH	Cuyahoga	summer	ocm	0.1306	1.0998
3903500381	OH	Cuyahoga	summer	ec	0.0419	0.9354
3903500381	OH	Cuyahoga	summer	soil	0.0583	1.0906
3903500381	OH	Cuyahoga	summer	nh4	0.1074	0.7038
3903500381	OH	Cuyahoga	summer	pbw	0.1183	0.6674
3903500381	OH	Cuyahoga	fall	so4	0.2055	0.8193
3903500381	OH	Cuyahoga	fall	no3	0.1275	0.9189
3903500381	OH	Cuyahoga	fall	ocm	0.2234	1.0245
3903500381	OH	Cuyahoga	fall	ec	0.0499	0.8913
3903500381	OH	Cuyahoga	fall	soil	0.0675	1.0927
3903500381	OH	Cuyahoga	fall	nh4	0.1034	0.8615
3903500381	OH	Cuyahoga	fall	pbw	0.0637	0.8564

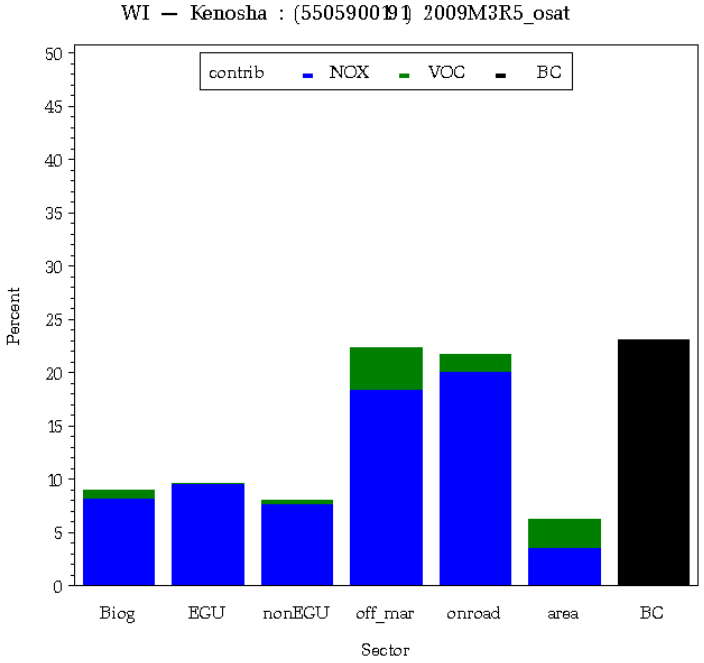
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3904900241	OH	Franklin	winter	so4	0.2555	0.8622
3904900241	OH	Franklin	winter	no3	0.2373	1.0002
3904900241	OH	Franklin	winter	ocm	0.2082	0.974
3904900241	OH	Franklin	winter	ec	0.0375	0.8537
3904900241	OH	Franklin	winter	soil	0.0259	1.0844
3904900241	OH	Franklin	winter	nh4	0.1495	0.9261
3904900241	OH	Franklin	winter	pbw	0.0861	0.9274
3904900241	OH	Franklin	spring	so4	0.3754	0.6615
3904900241	OH	Franklin	spring	no3	0.0176	0.8436
3904900241	OH	Franklin	spring	ocm	0.2069	1.062
3904900241	OH	Franklin	spring	ec	0.0405	0.8678
3904900241	OH	Franklin	spring	soil	0.0371	1.0551
3904900241	OH	Franklin	spring	nh4	0.1296	0.7212
3904900241	OH	Franklin	spring	pbw	0.128	0.6992
3904900241	OH	Franklin	summer	so4	0.3703	0.622
3904900241	OH	Franklin	summer	no3	0	0.9056
3904900241	OH	Franklin	summer	ocm	0.1343	1.0654
3904900241	OH	Franklin	summer	ec	0.0311	0.8565
3904900241	OH	Franklin	summer	soil	0.0267	1.0667
3904900241	OH	Franklin	summer	nh4	0.1142	0.7021
3904900241	OH	Franklin	summer	pbw	0.1186	0.6614
3904900241	OH	Franklin	fall	so4	0.2692	0.8119
3904900241	OH	Franklin	fall	no3	0.1186	0.9099
3904900241	OH	Franklin	fall	ocm	0.2489	1.019
3904900241	OH	Franklin	fall	ec	0.0533	0.8371
3904900241	OH	Franklin	fall	soil	0.0423	1.0924
3904900241	OH	Franklin	fall	nh4	0.1217	0.8539
3904900241	OH	Franklin	fall	pbw	0.0821	0.8519
3906100141	OH	Hamilton	winter	so4	0.2685	0.8104
3906100141	OH	Hamilton	winter	no3	0.2378	1.0886
3906100141	OH	Hamilton	winter	ocm	0.19	0.961
3906100141	OH	Hamilton	winter	ec	0.035	0.8969
3906100141	OH	Hamilton	winter	soil	0.0229	1.4146
3906100141	OH	Hamilton	winter	nh4	0.1583	0.9077
3906100141	OH	Hamilton	winter	pbw	0.0874	0.8687
3906100141	OH	Hamilton	spring	so4	0.3583	0.6331
3906100141	OH	Hamilton	spring	no3	0.0025	1.0155
3906100141	OH	Hamilton	spring	ocm	0.1986	1.0798
3906100141	OH	Hamilton	spring	ec	0.0466	0.9228
3906100141	OH	Hamilton	spring	soil	0.0289	1.3785
3906100141	OH	Hamilton	spring	nh4	0.1215	0.6968
3906100141	OH	Hamilton	spring	pbw	0.128	0.6307
3906100141	OH	Hamilton	summer	so4	0.3722	0.577
3906100141	OH	Hamilton	summer	no3	0	1.0923
3906100141	OH	Hamilton	summer	ocm	0.121	1.082
3906100141	OH	Hamilton	summer	ec	0.0309	0.9099
3906100141	OH	Hamilton	summer	soil	0.0199	1.537
3906100141	OH	Hamilton	summer	nh4	0.1178	0.6441
3906100141	OH	Hamilton	summer	pbw	0.1261	0.5734
3906100141	OH	Hamilton	fall	so4	0.2608	0.7754
3906100141	OH	Hamilton	fall	no3	0.1184	0.9857
3906100141	OH	Hamilton	fall	ocm	0.213	1.0235
3906100141	OH	Hamilton	fall	ec	0.0512	0.8876
3906100141	OH	Hamilton	fall	soil	0.0328	1.4007
3906100141	OH	Hamilton	fall	nh4	0.1254	0.846
3906100141	OH	Hamilton	fall	pbw	0.0828	0.8172

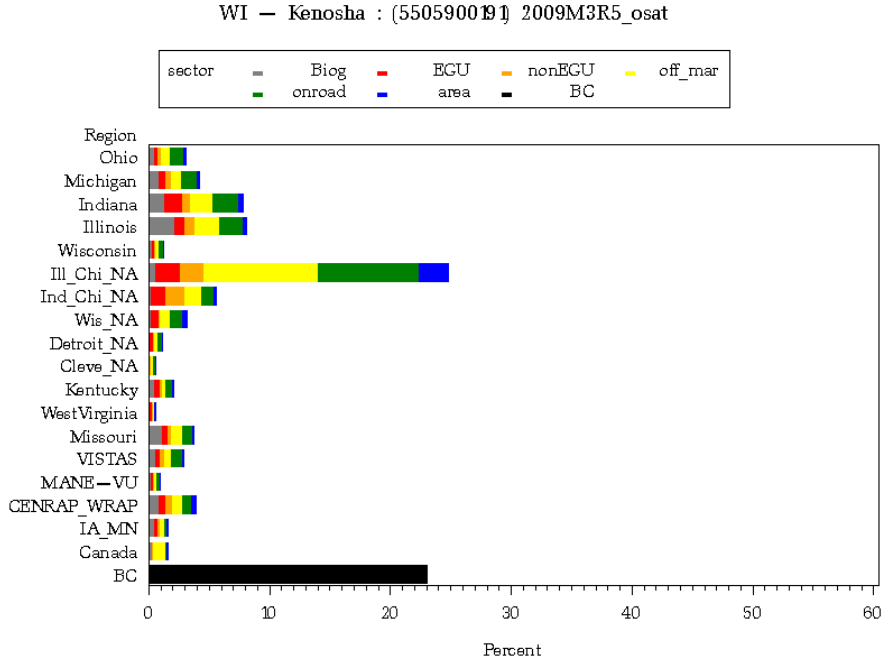
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3908110011	OH	Jefferson	winter	so4	0.2367	0.8217
3908110011	OH	Jefferson	winter	no3	0.1709	1.0522
3908110011	OH	Jefferson	winter	ocm	0.3288	0.8819
3908110011	OH	Jefferson	winter	ec	0.0435	0.9091
3908110011	OH	Jefferson	winter	soil	0.0272	0.4368
3908110011	OH	Jefferson	winter	nh4	0.1199	0.8904
3908110011	OH	Jefferson	winter	pbw	0.073	0.8583
3908110011	OH	Jefferson	spring	so4	0.3508	0.6666
3908110011	OH	Jefferson	spring	no3	0.0154	0.9156
3908110011	OH	Jefferson	spring	ocm	0.3078	0.9995
3908110011	OH	Jefferson	spring	ec	0.0395	0.9853
3908110011	OH	Jefferson	spring	soil	0.0407	0.4844
3908110011	OH	Jefferson	spring	nh4	0.114	0.7054
3908110011	OH	Jefferson	spring	pbw	0.1095	0.6713
3908110011	OH	Jefferson	summer	so4	0.3779	0.6156
3908110011	OH	Jefferson	summer	no3	0	1.0837
3908110011	OH	Jefferson	summer	ocm	0.2098	1.0145
3908110011	OH	Jefferson	summer	ec	0.0308	0.9689
3908110011	OH	Jefferson	summer	soil	0.0323	0.3632
3908110011	OH	Jefferson	summer	nh4	0.1065	0.6428
3908110011	OH	Jefferson	summer	pbw	0.1007	0.625
3908110011	OH	Jefferson	fall	so4	0.2315	0.7694
3908110011	OH	Jefferson	fall	no3	0.0702	1.0302
3908110011	OH	Jefferson	fall	ocm	0.372	0.9312
3908110011	OH	Jefferson	fall	ec	0.051	0.9086
3908110011	OH	Jefferson	fall	soil	0.0344	0.4555
3908110011	OH	Jefferson	fall	nh4	0.0859	0.8284
3908110011	OH	Jefferson	fall	pbw	0.0629	0.7951
3911300321	OH	Montgomer	winter	so4	0.2613	0.8598
3911300321	OH	Montgomer	winter	no3	0.2407	1.029
3911300321	OH	Montgomer	winter	ocm	0.1954	0.9442
3911300321	OH	Montgomer	winter	ec	0.036	0.8746
3911300321	OH	Montgomer	winter	soil	0.0259	1.1295
3911300321	OH	Montgomer	winter	nh4	0.1531	0.9304
3911300321	OH	Montgomer	winter	pbw	0.0876	0.9205
3911300321	OH	Montgomer	spring	so4	0.3659	0.6606
3911300321	OH	Montgomer	spring	no3	0.0163	0.8639
3911300321	OH	Montgomer	spring	ocm	0.1895	1.0976
3911300321	OH	Montgomer	spring	ec	0.0442	0.9417
3911300321	OH	Montgomer	spring	soil	0.0253	1.0873
3911300321	OH	Montgomer	spring	nh4	0.1313	0.7149
3911300321	OH	Montgomer	spring	pbw	0.1326	0.6839
3911300321	OH	Montgomer	summer	so4	0.375	0.6234
3911300321	OH	Montgomer	summer	no3	0	0.9474
3911300321	OH	Montgomer	summer	ocm	0.128	1.1047
3911300321	OH	Montgomer	summer	ec	0.029	0.9496
3911300321	OH	Montgomer	summer	soil	0.0205	1.1299
3911300321	OH	Montgomer	summer	nh4	0.1114	0.6931
3911300321	OH	Montgomer	summer	pbw	0.1114	0.6482
3911300321	OH	Montgomer	fall	so4	0.3062	0.8033
3911300321	OH	Montgomer	fall	no3	0.1012	0.9634
3911300321	OH	Montgomer	fall	ocm	0.2221	1.0158
3911300321	OH	Montgomer	fall	ec	0.0514	0.877
3911300321	OH	Montgomer	fall	soil	0.028	1.1391
3911300321	OH	Montgomer	fall	nh4	0.1352	0.8625
3911300321	OH	Montgomer	fall	pbw	0.0982	0.8475

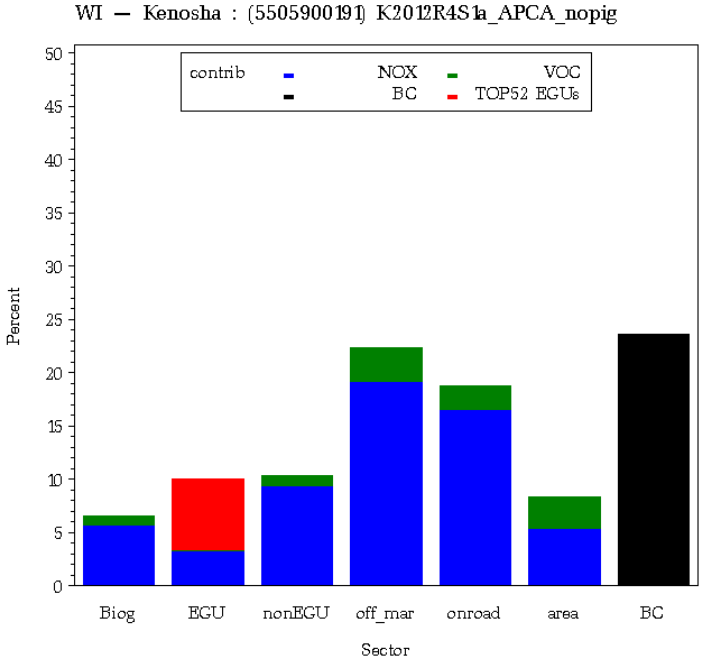
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3915100171	OH	Stark	winter	so4	0.2362	0.8558
3915100171	OH	Stark	winter	no3	0.2234	1.0222
3915100171	OH	Stark	winter	ocm	0.2478	0.9255
3915100171	OH	Stark	winter	ec	0.0414	0.8866
3915100171	OH	Stark	winter	soil	0.0334	1.099
3915100171	OH	Stark	winter	nh4	0.1376	0.925
3915100171	OH	Stark	winter	pbw	0.0802	0.9155
3915100171	OH	Stark	spring	so4	0.3581	0.6834
3915100171	OH	Stark	spring	no3	0.0236	0.855
3915100171	OH	Stark	spring	ocm	0.221	1.0892
3915100171	OH	Stark	spring	ec	0.0501	1.0017
3915100171	OH	Stark	spring	soil	0.058	1.0528
3915100171	OH	Stark	spring	nh4	0.1288	0.7264
3915100171	OH	Stark	spring	pbw	0.1256	0.7009
3915100171	OH	Stark	summer	so4	0.3621	0.6277
3915100171	OH	Stark	summer	no3	0	0.8203
3915100171	OH	Stark	summer	ocm	0.1483	1.0984
3915100171	OH	Stark	summer	ec	0.0403	1.016
3915100171	OH	Stark	summer	soil	0.037	1.0781
3915100171	OH	Stark	summer	nh4	0.1157	0.6739
3915100171	OH	Stark	summer	pbw	0.124	0.651
3915100171	OH	Stark	fall	so4	0.2293	0.8041
3915100171	OH	Stark	fall	no3	0.1262	0.9363
3915100171	OH	Stark	fall	ocm	0.2722	1.0226
3915100171	OH	Stark	fall	ec	0.0545	0.9202
3915100171	OH	Stark	fall	soil	0.0461	1.0959
3915100171	OH	Stark	fall	nh4	0.1105	0.8549
3915100171	OH	Stark	fall	pbw	0.0706	0.8428
3915300171	OH	Summit	winter	so4	0.2511	0.8771
3915300171	OH	Summit	winter	no3	0.2376	1.0052
3915300171	OH	Summit	winter	ocm	0.2185	0.9429
3915300171	OH	Summit	winter	ec	0.0334	0.8677
3915300171	OH	Summit	winter	soil	0.0255	1.0835
3915300171	OH	Summit	winter	nh4	0.1489	0.9374
3915300171	OH	Summit	winter	pbw	0.0851	0.945
3915300171	OH	Summit	spring	so4	0.387	0.7046
3915300171	OH	Summit	spring	no3	0.0072	0.8466
3915300171	OH	Summit	spring	ocm	0.1901	1.0967
3915300171	OH	Summit	spring	ec	0.035	0.9482
3915300171	OH	Summit	spring	soil	0.0304	1.0524
3915300171	OH	Summit	spring	nh4	0.1294	0.7521
3915300171	OH	Summit	spring	pbw	0.1342	0.7384
3915300171	OH	Summit	summer	so4	0.3694	0.6378
3915300171	OH	Summit	summer	no3	0	0.8587
3915300171	OH	Summit	summer	ocm	0.1417	1.1077
3915300171	OH	Summit	summer	ec	0.0332	0.9506
3915300171	OH	Summit	summer	soil	0.0198	1.0744
3915300171	OH	Summit	summer	nh4	0.1121	0.6961
3915300171	OH	Summit	summer	pbw	0.1146	0.6691
3915300171	OH	Summit	fall	so4	0.2443	0.8074
3915300171	OH	Summit	fall	no3	0.1175	0.9392
3915300171	OH	Summit	fall	ocm	0.2636	1.0252
3915300171	OH	Summit	fall	ec	0.0623	0.8883
3915300171	OH	Summit	fall	soil	0.0494	1.086
3915300171	OH	Summit	fall	nh4	0.109	0.8622
3915300171	OH	Summit	fall	pbw	0.0723	0.8506

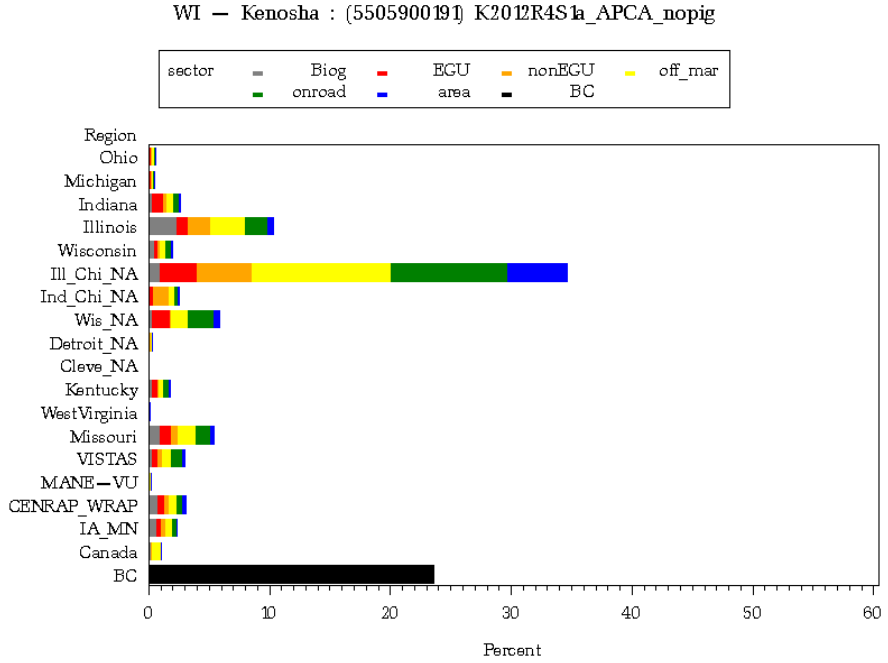
APPENDIX II

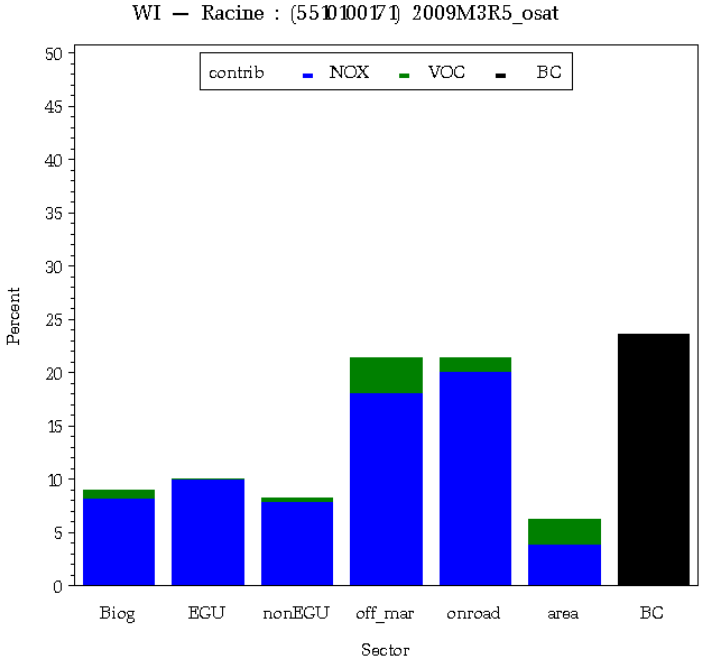
Ozone Source Apportionment Modeling Results


WI — Kenosha : (550590019) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Kenosha : (550590019) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Kenosha : (550590019) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Kenosha : (550590019) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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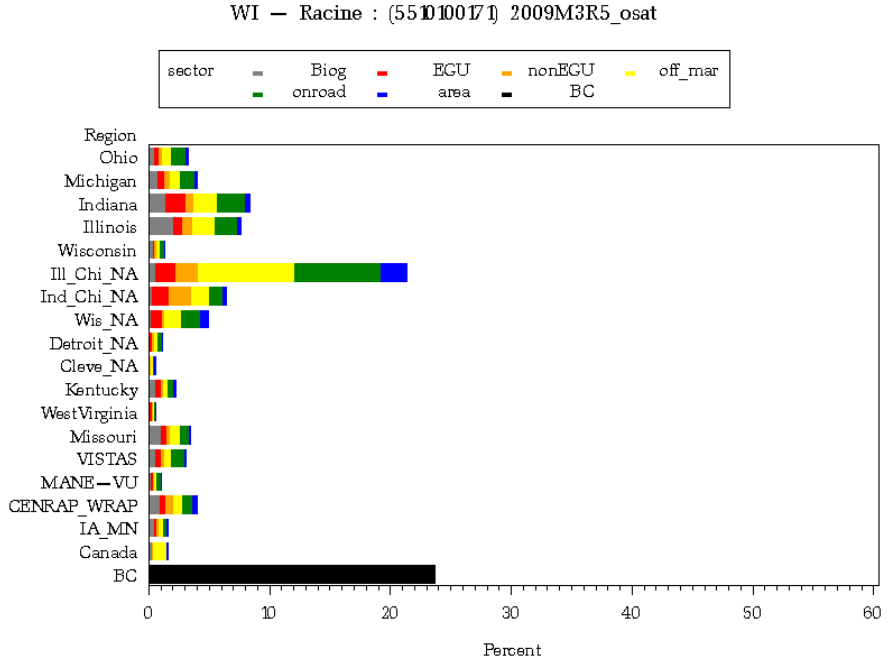
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector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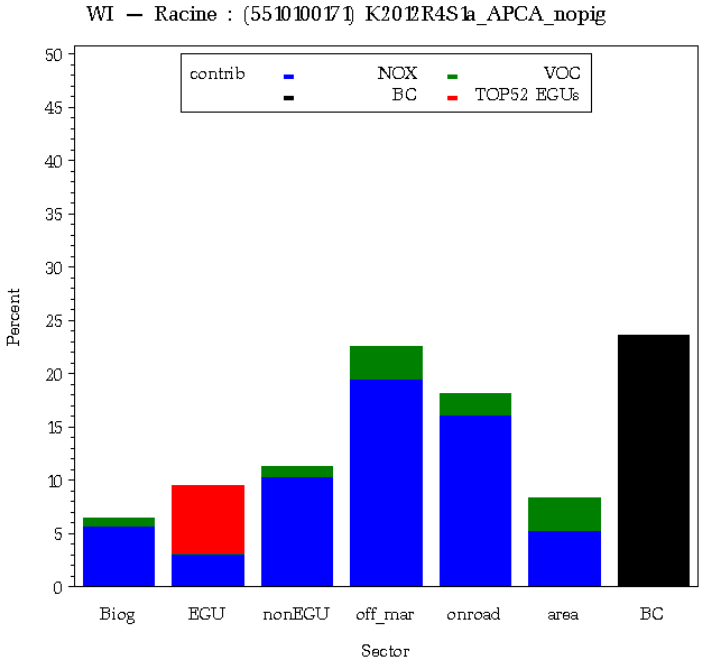
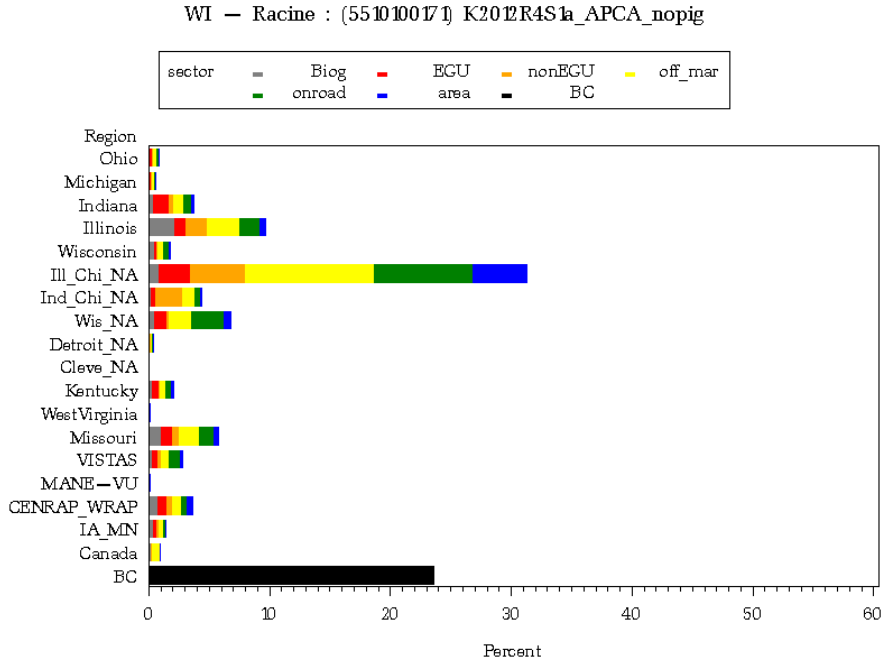
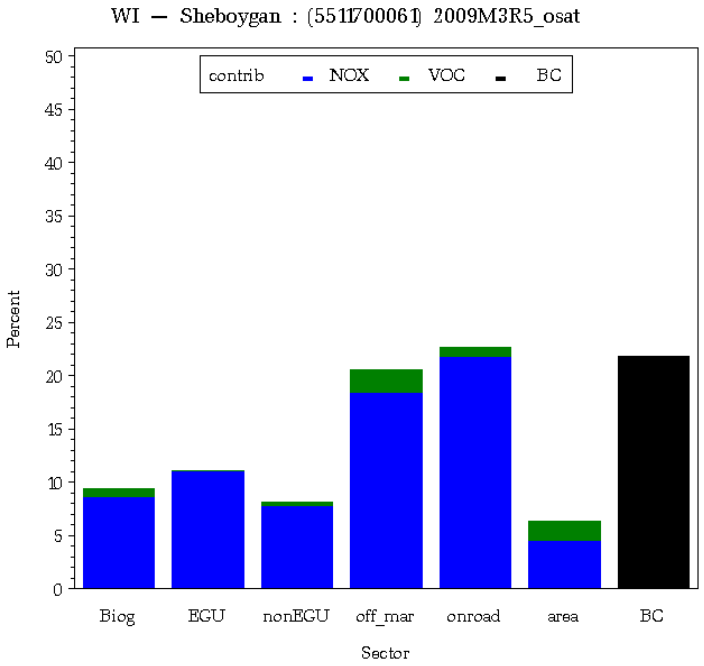
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Racine : (551010017) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Racine : (551010017) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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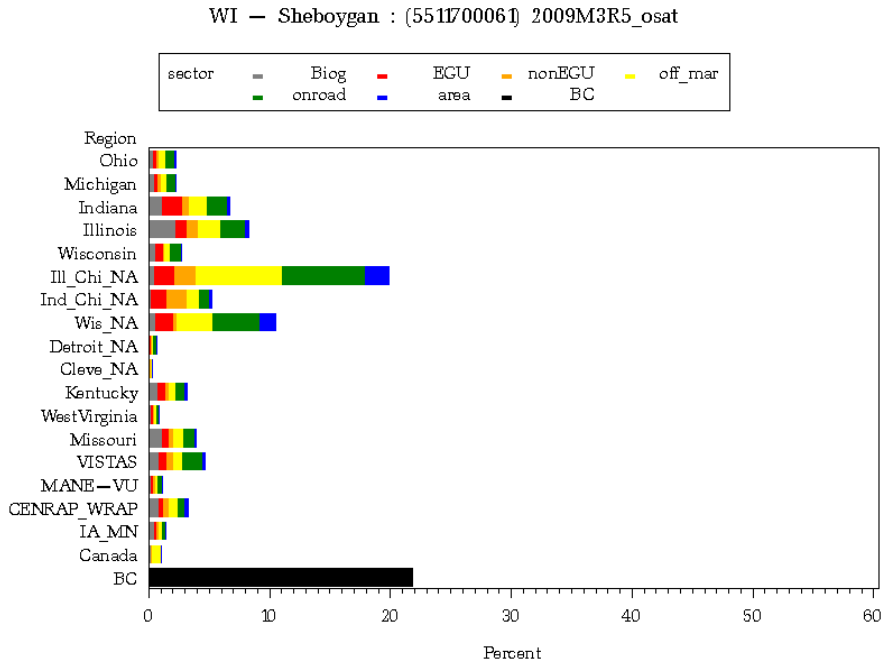
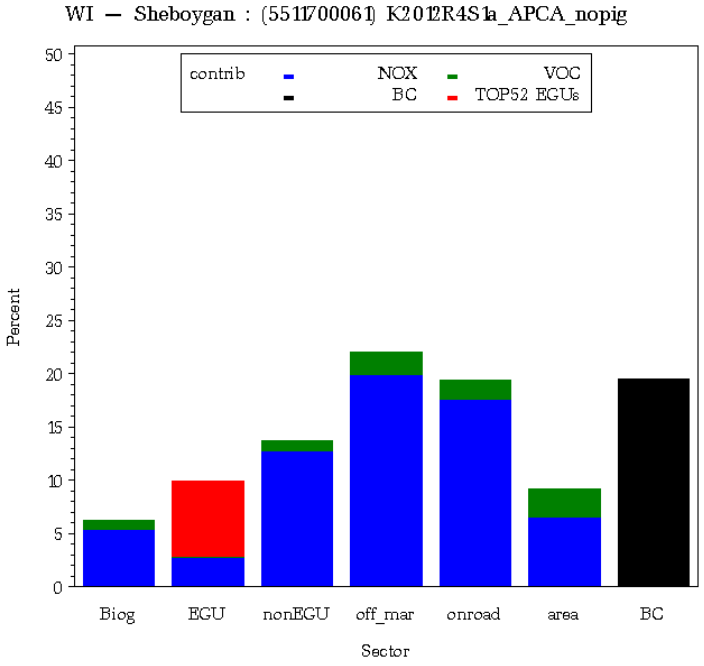
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Sheboygan : (551700061) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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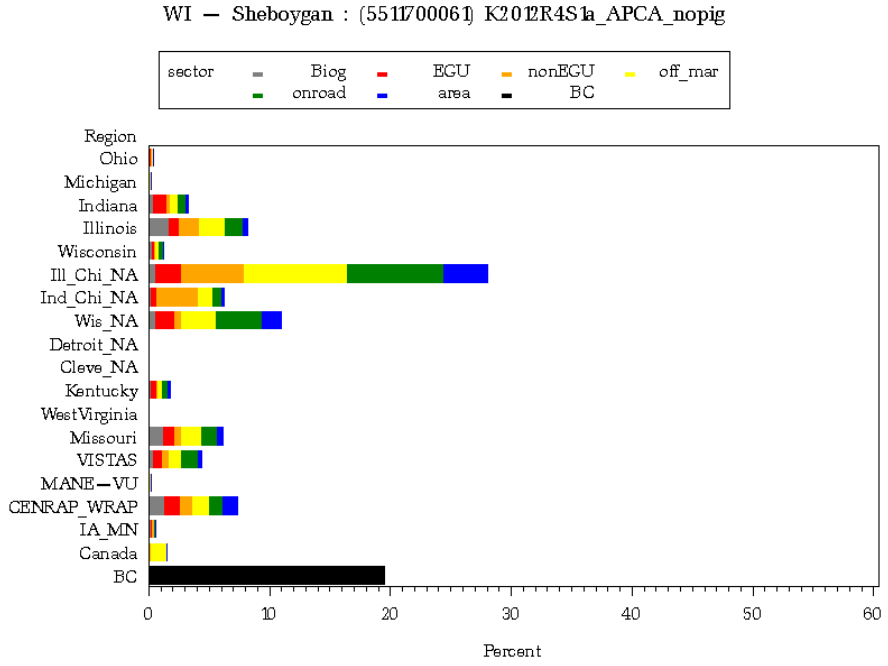
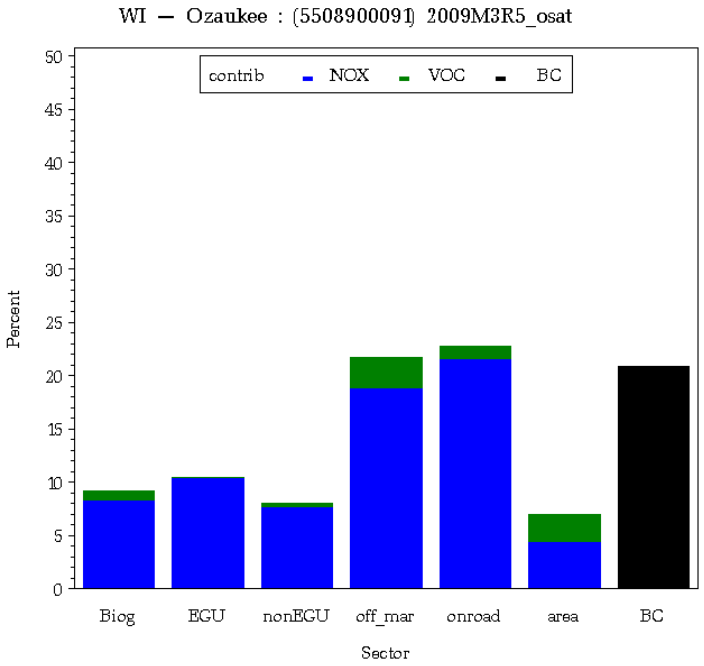
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Sheboygan : (551700061) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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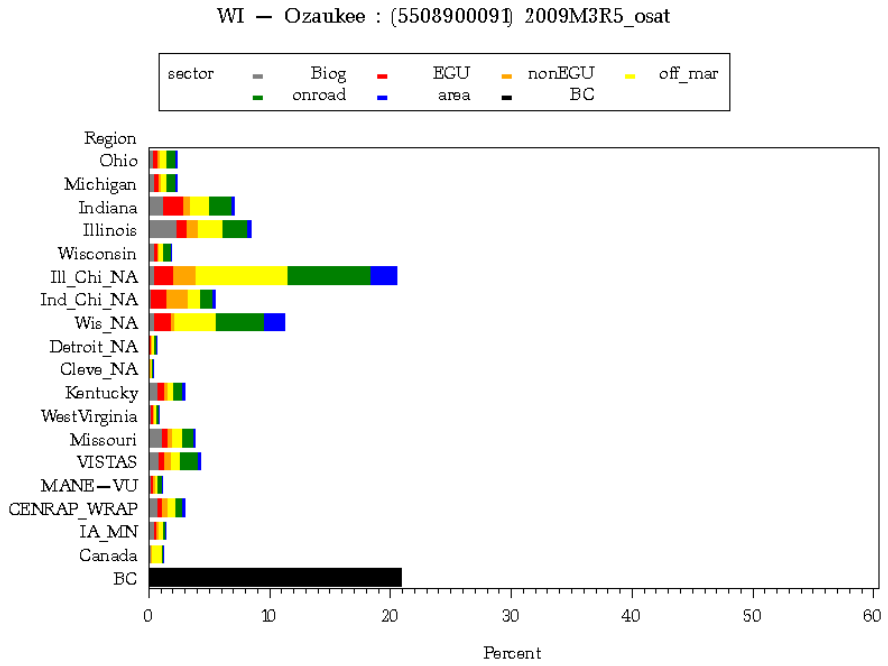
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector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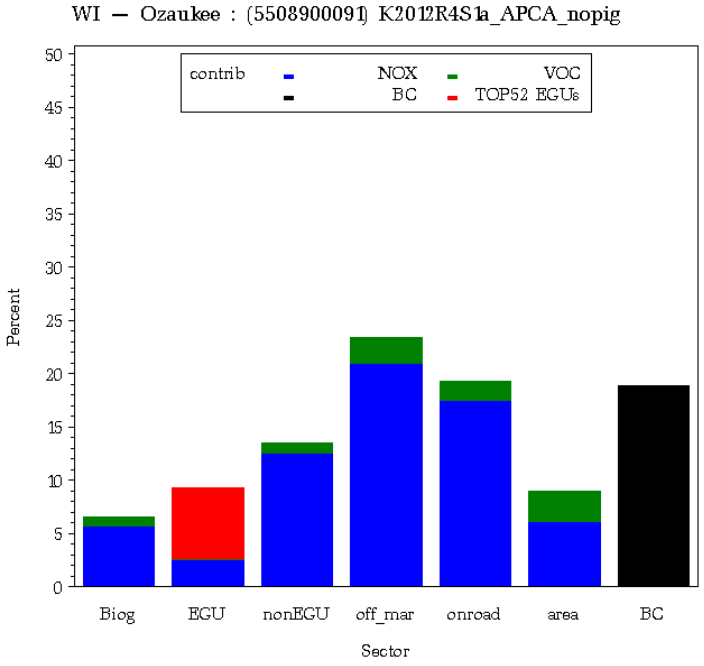
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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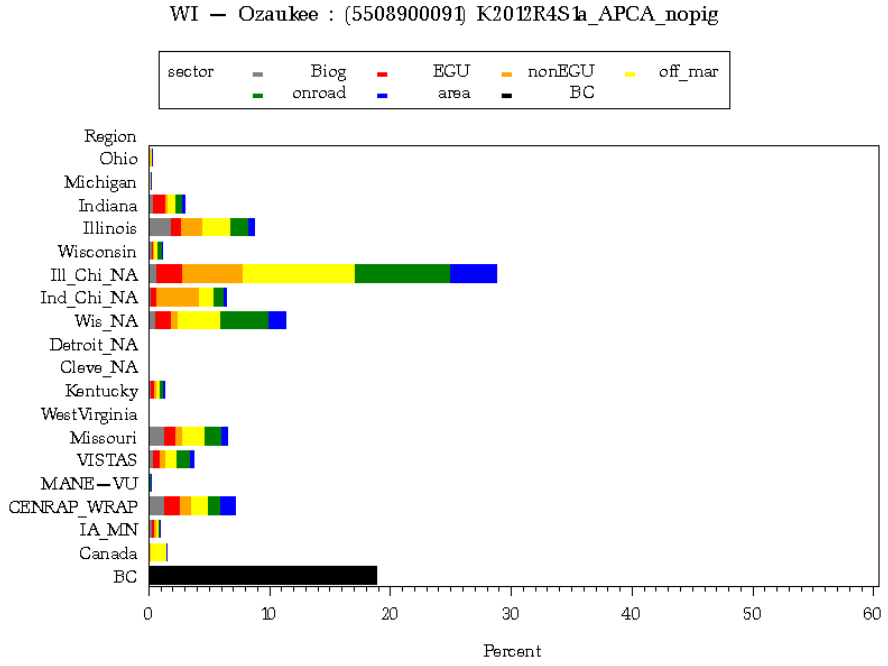
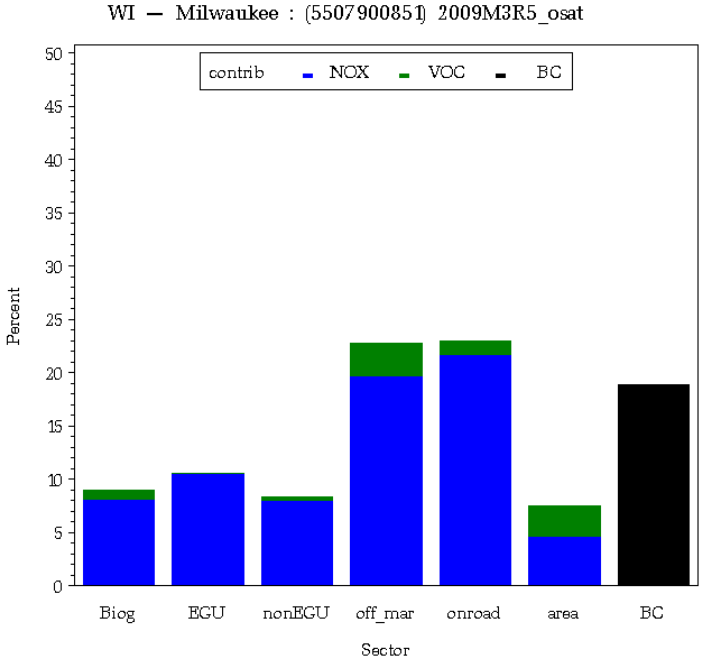
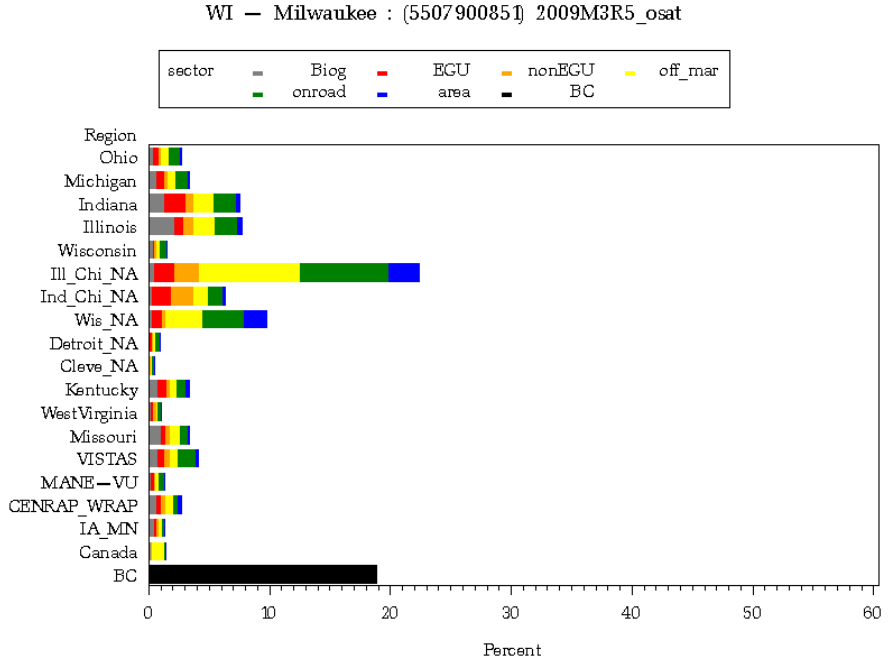
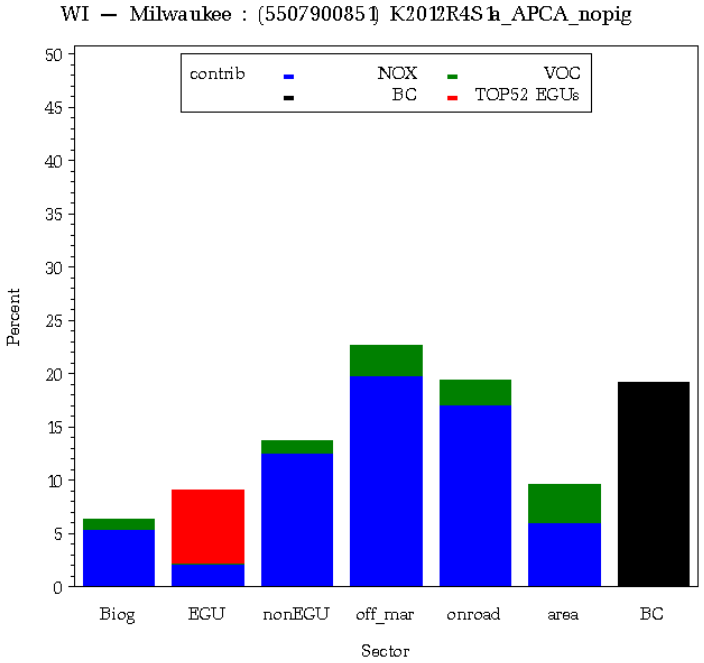
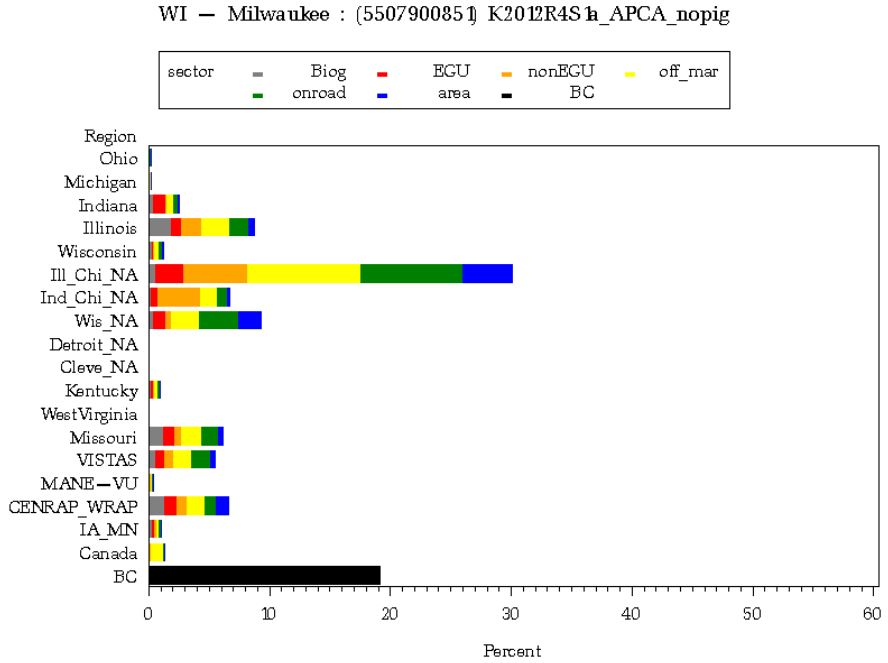
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

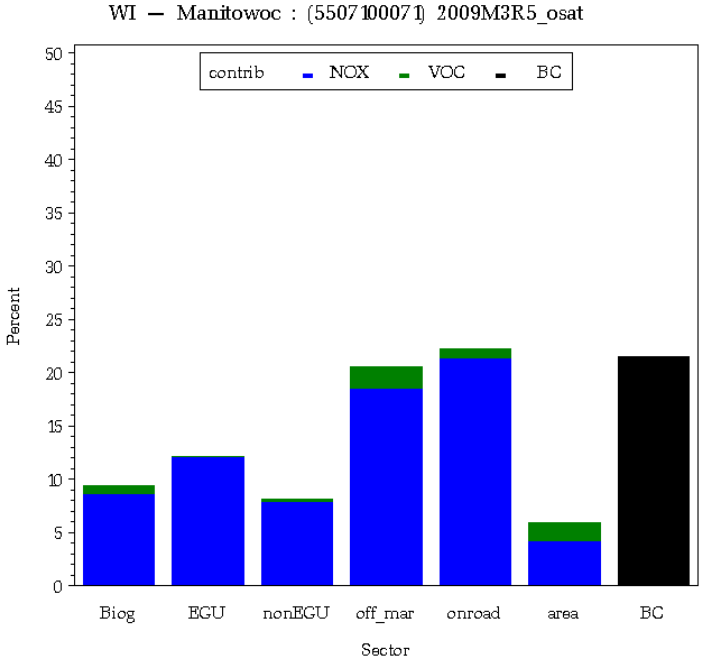

WI — Ozaukee : (5508900091) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

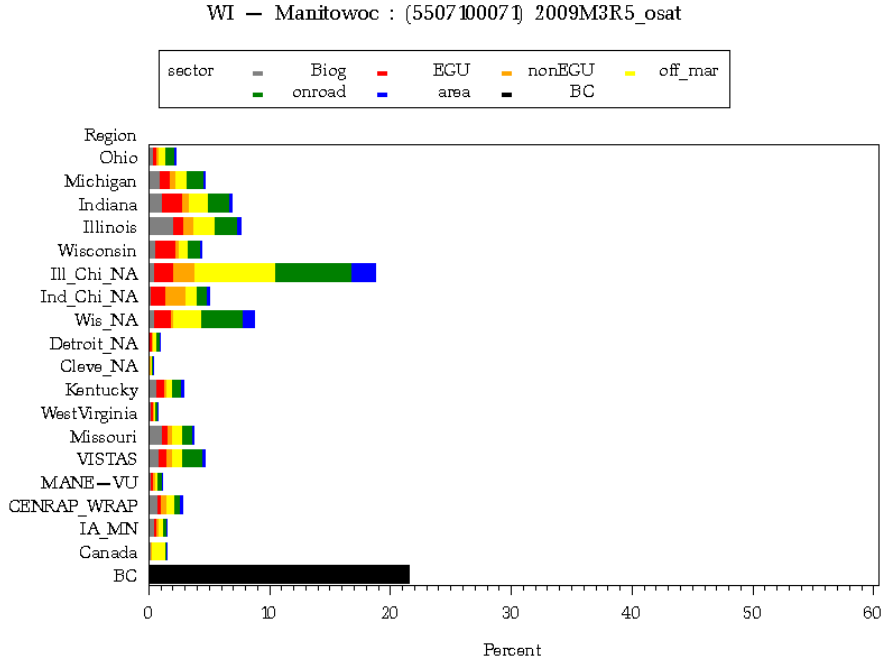

WI — Milwaukee : (550790085 1) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

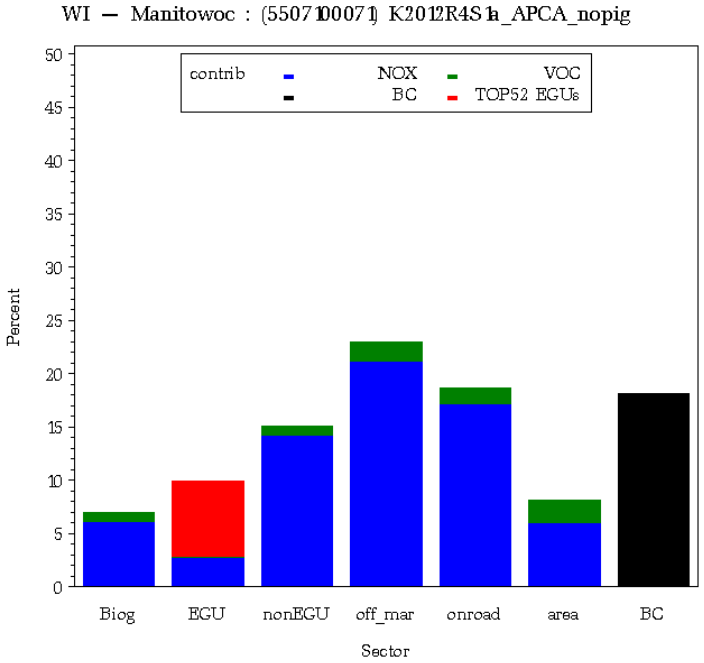

WI — Milwaukee : (550790085 1) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

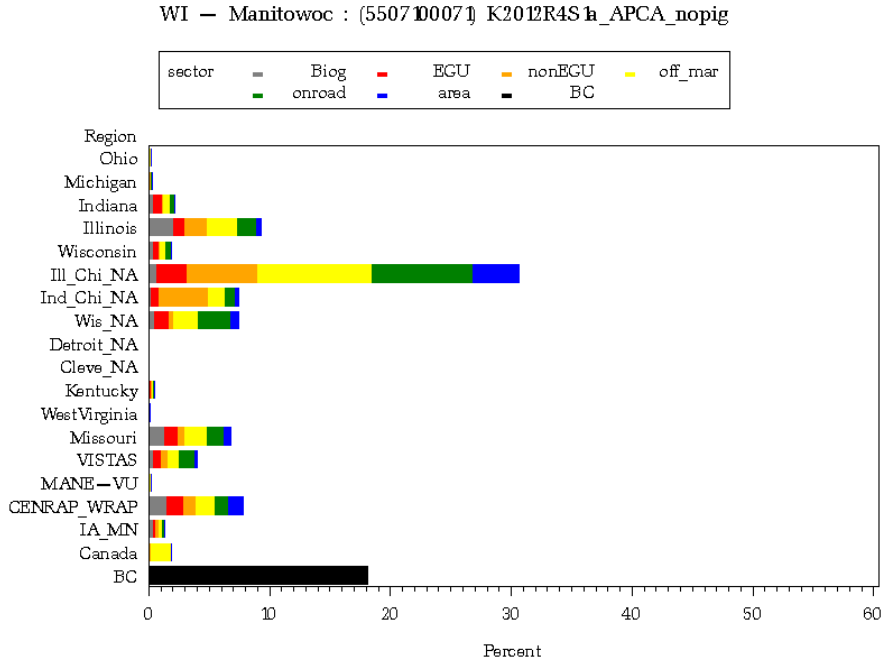

WI — Milwaukee : (550790085 1) K2012R4S ha_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

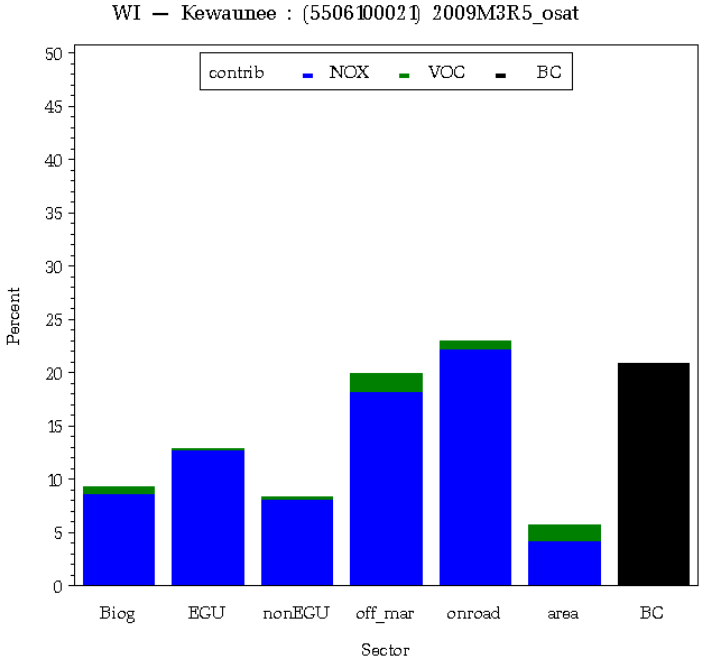

WI — Milwaukee : (550790085 1) K2012R4S ha_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

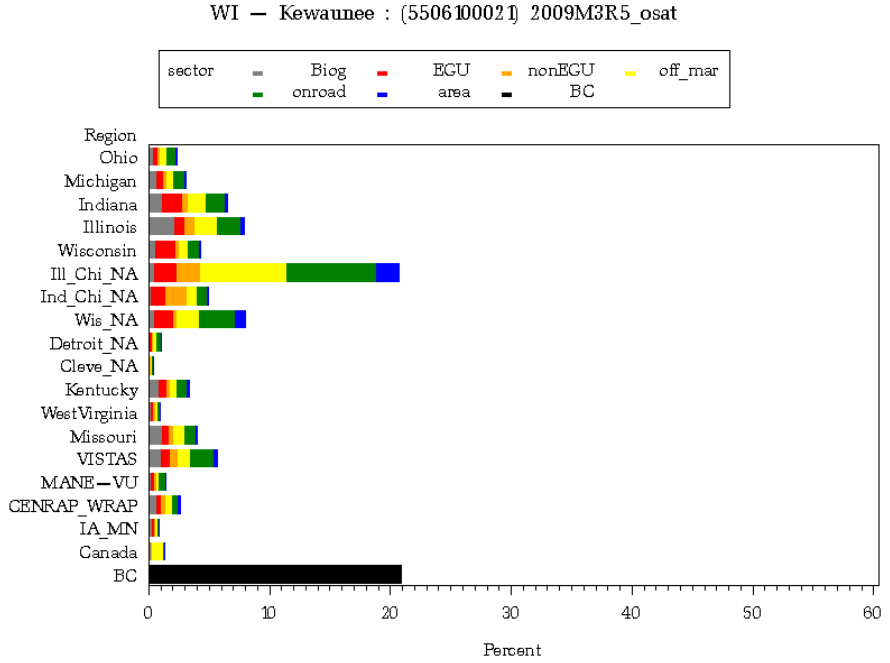

WI — Manitowoc : (550710071) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

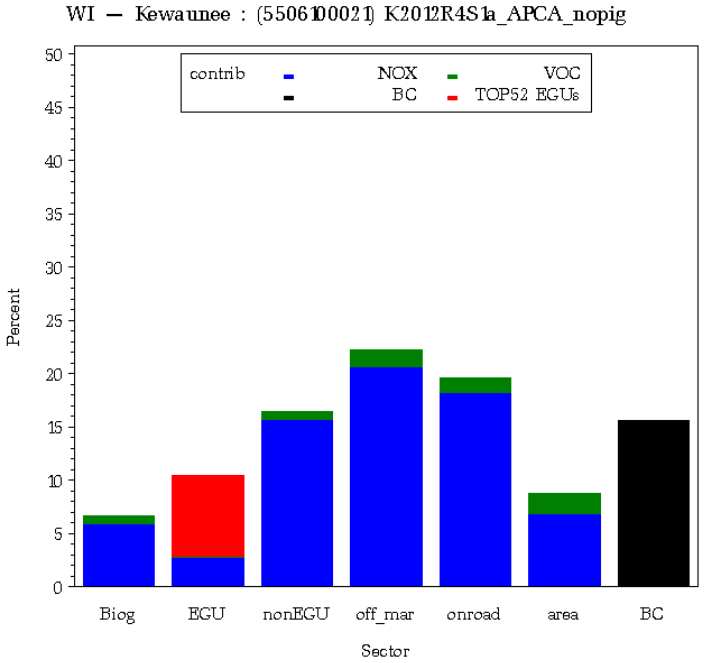

WI — Manitowoc : (550710071) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

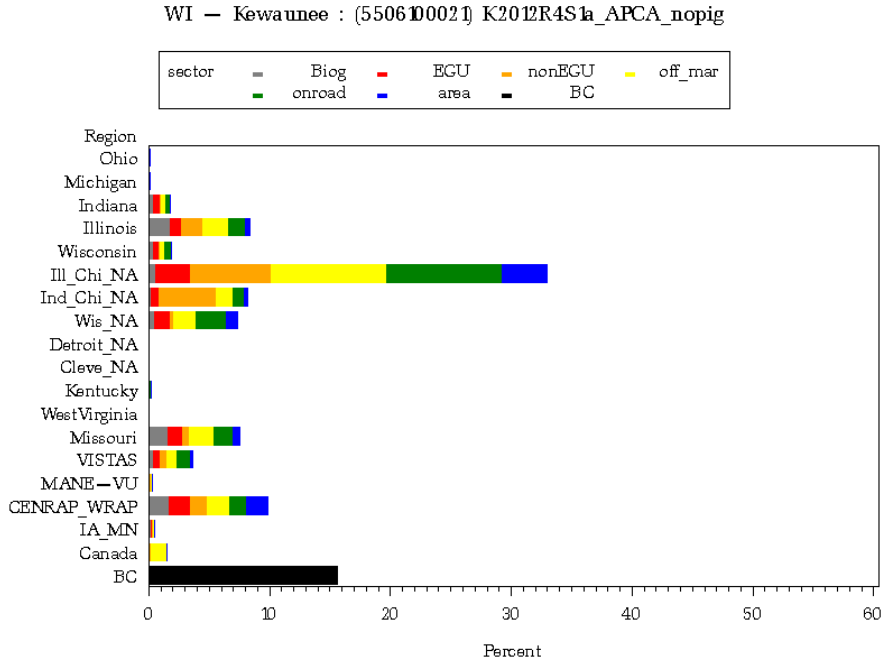

WI — Manitowoc : (550710071) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Manitowoc : (550710071) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Kewaunee : (550610002 1) 2009M3R5_osat
contrib NOX VOC BC
Percent
0 5 10 15 20 25 30 35 40 45 50
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Kewaunee : (550610002 1) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0 10 20 30 40 50 60
Percent


WI — Kewaunee : (550610002 1) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
0 5 10 15 20 25 30 35 40 45 50
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Kewaunee : (550610002 1) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
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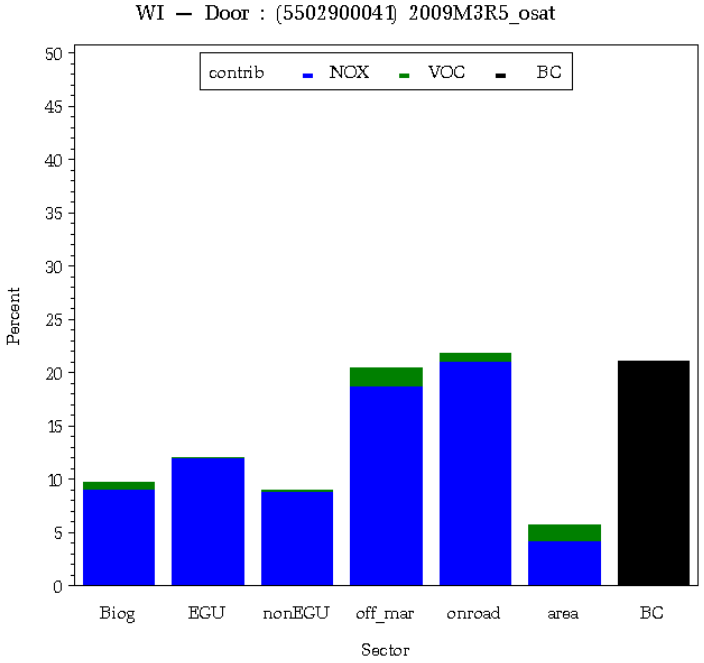
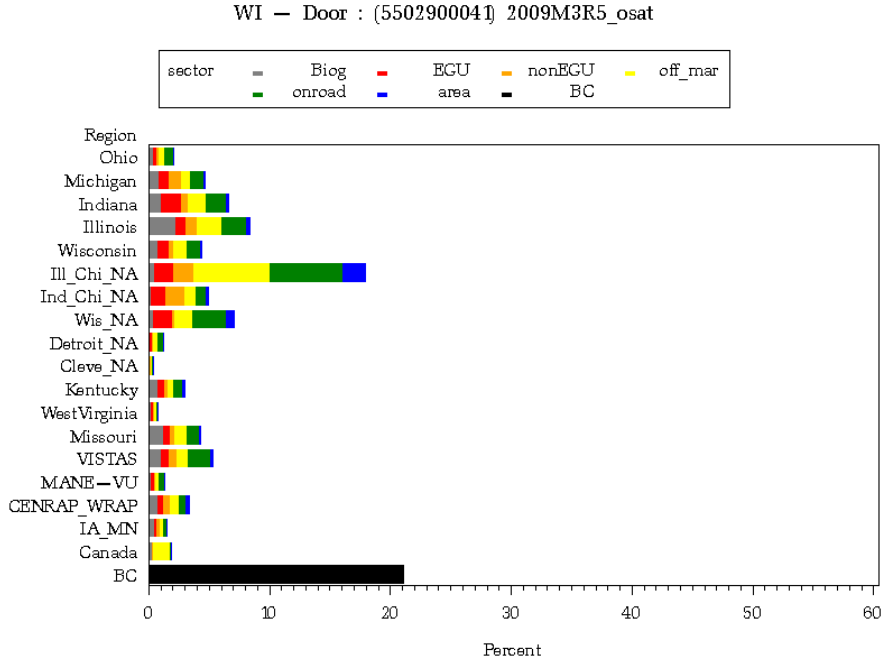
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0 10 20 30 40 50 60
Percent


WI — Door : (550290041) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Door : (550290041) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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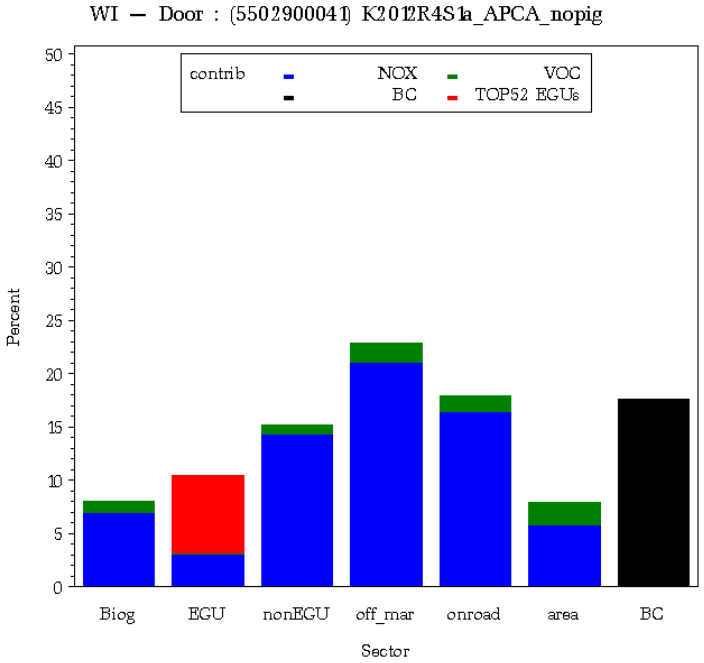
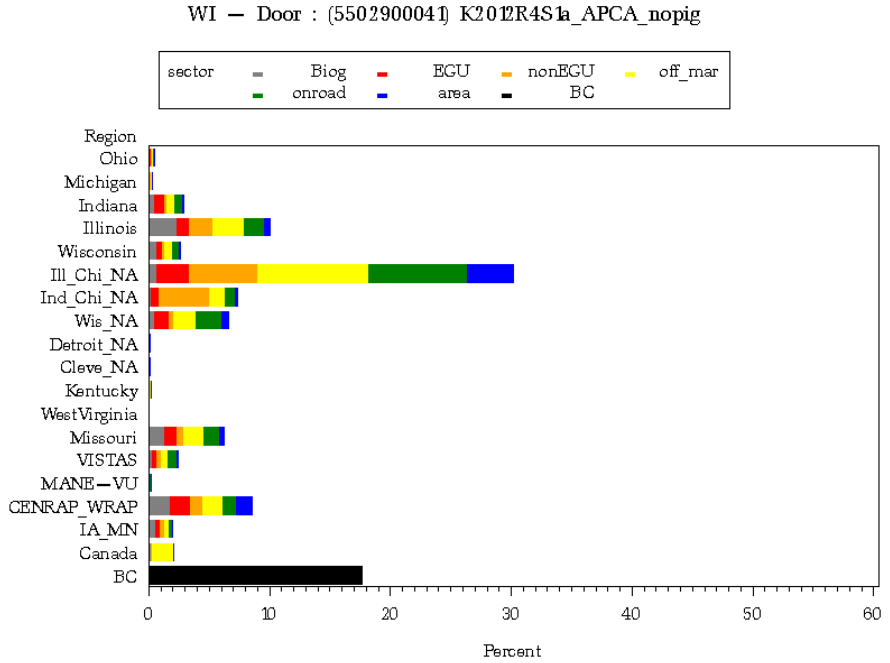
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Door : (550290041) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Door : (550290041) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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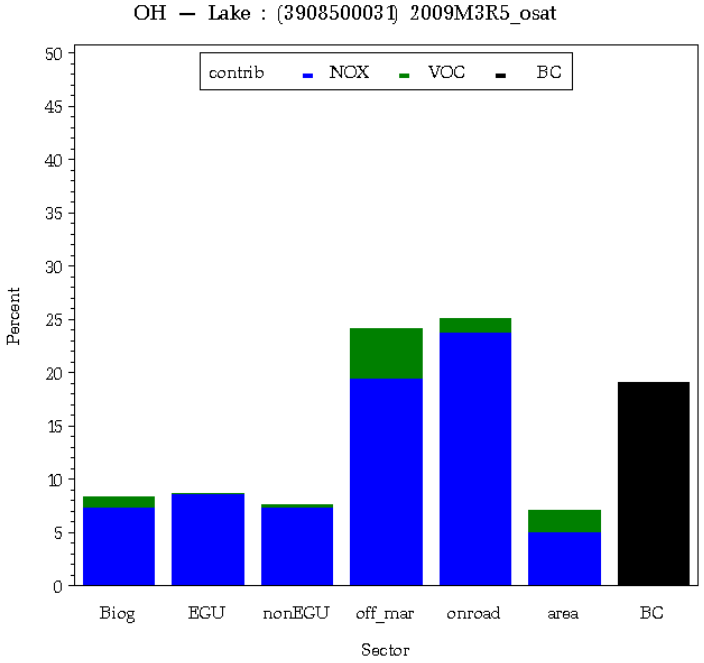
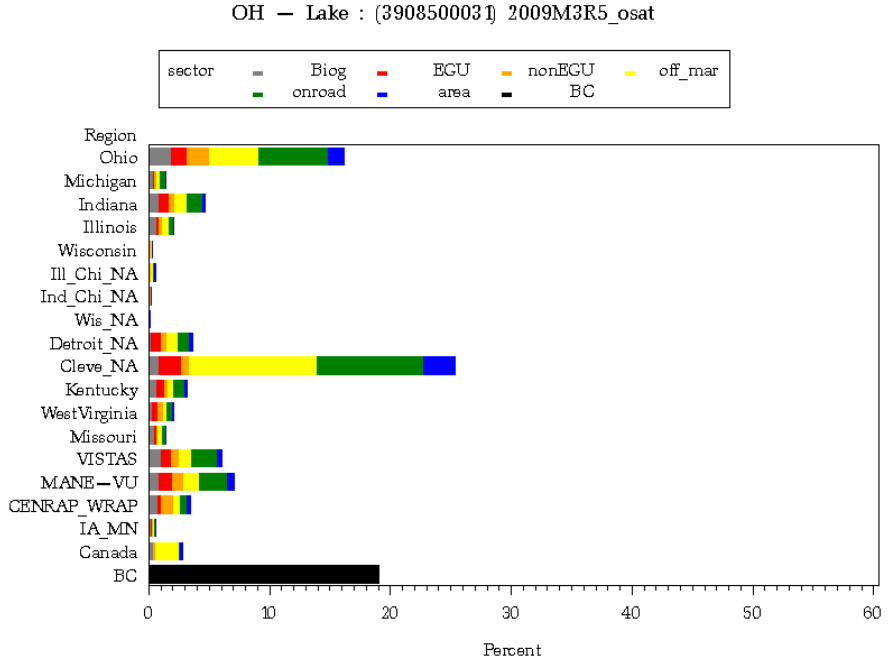
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Lake : (390850003) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


OH — Lake : (390850003) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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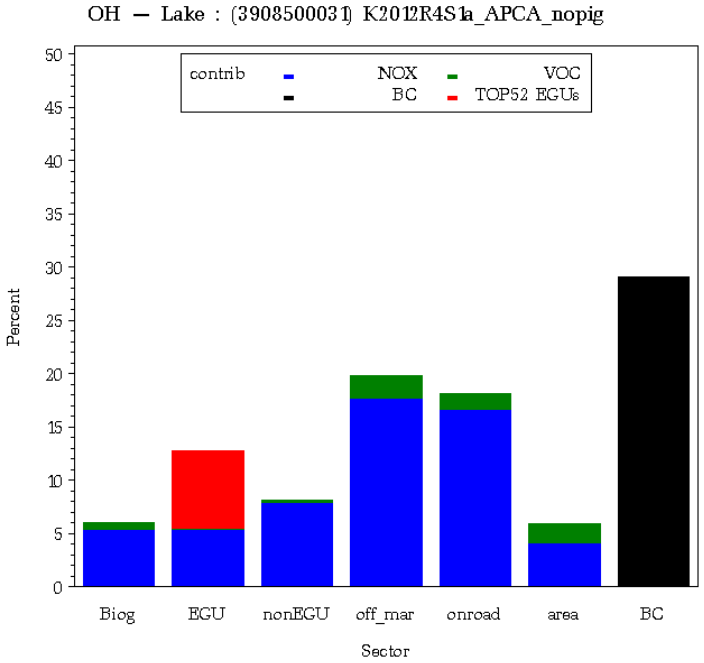
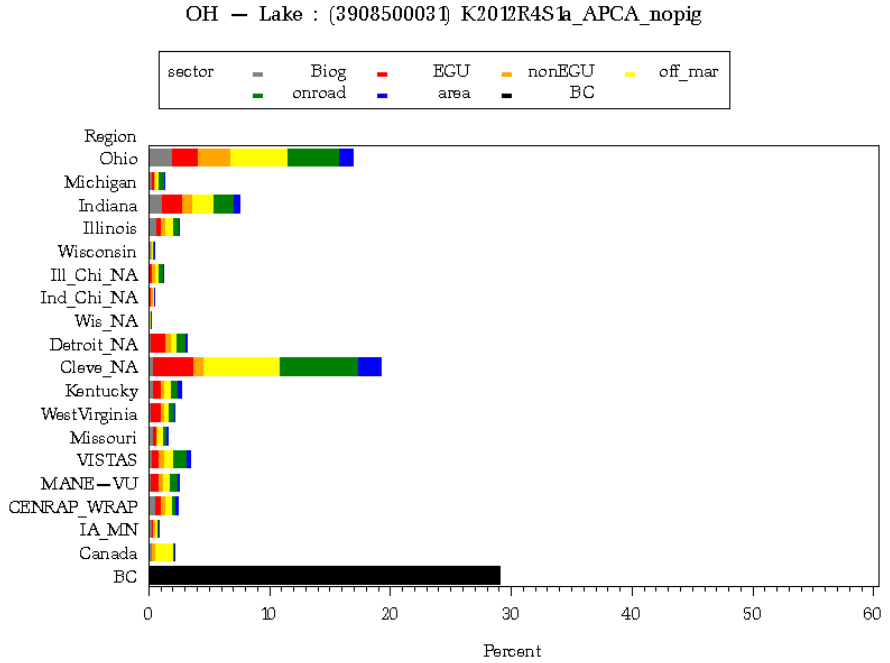
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Lake : (390850003) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


OH — Lake : (390850003) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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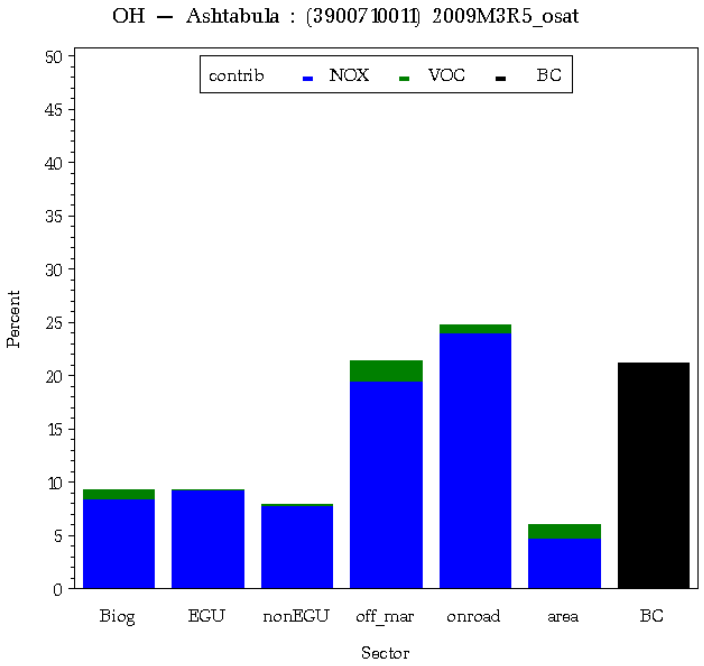
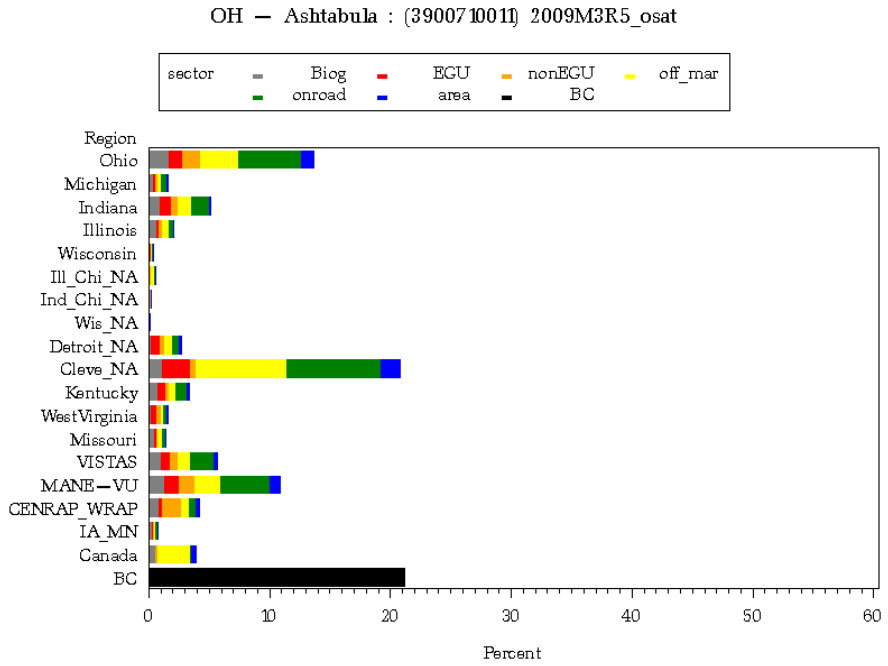
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Ashtabula : (390071001) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Ashtabula : (390071001) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
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Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
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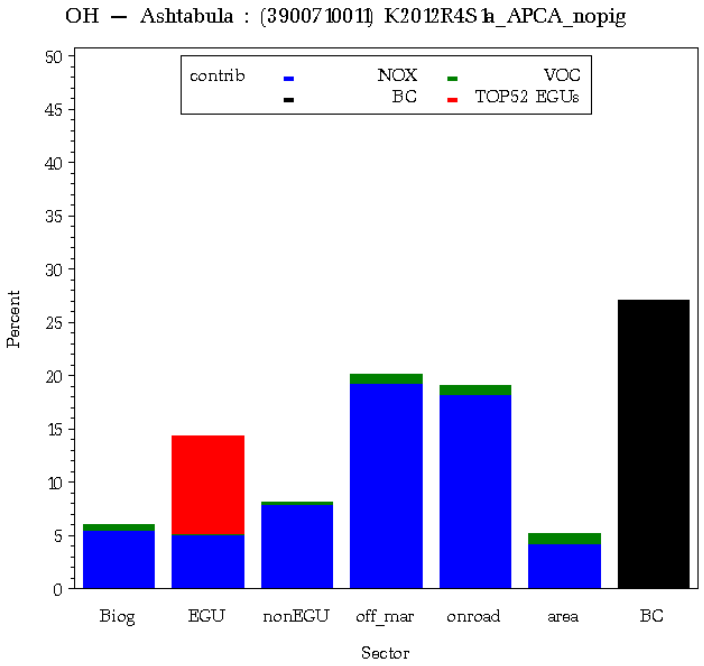
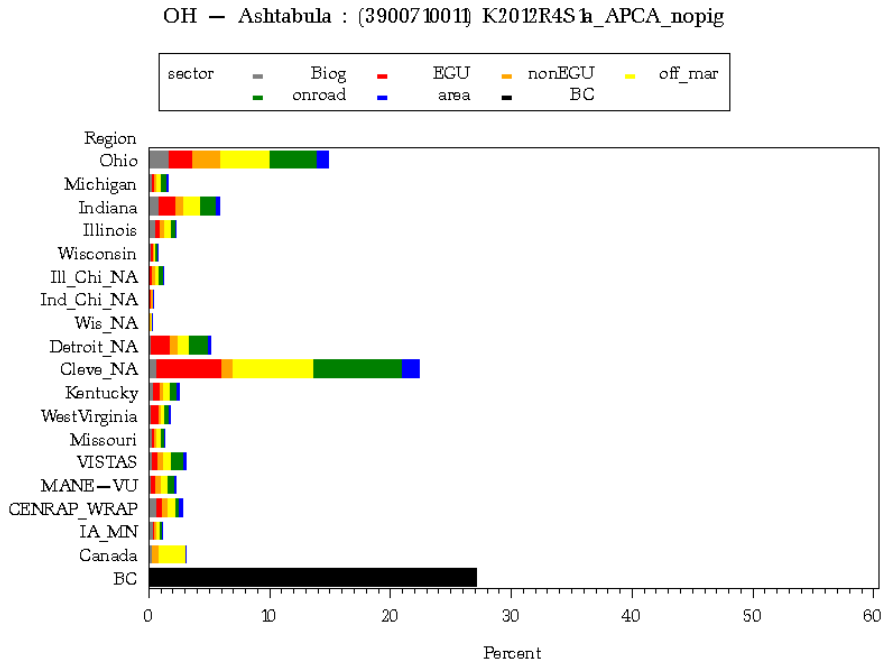
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Ashtabula : (390071001) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Ashtabula : (390071001) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
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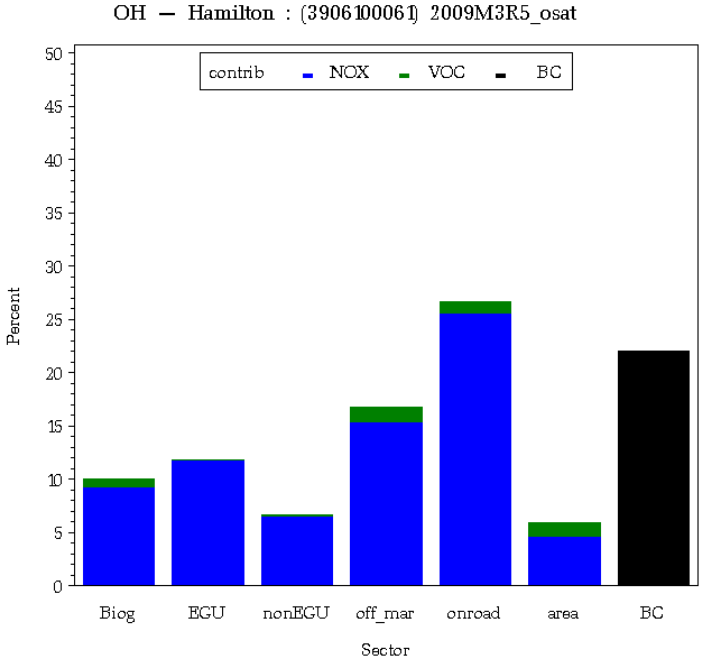
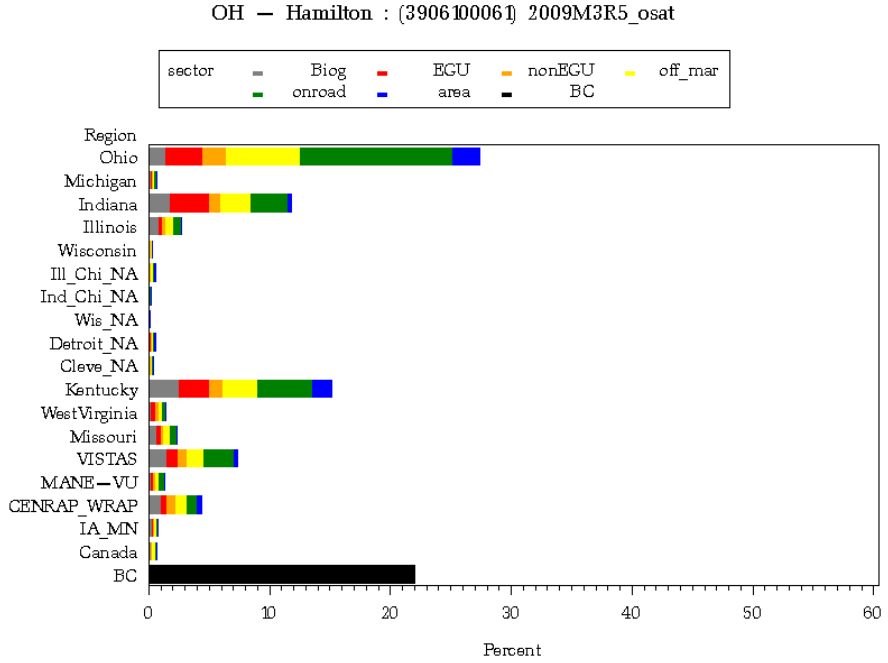
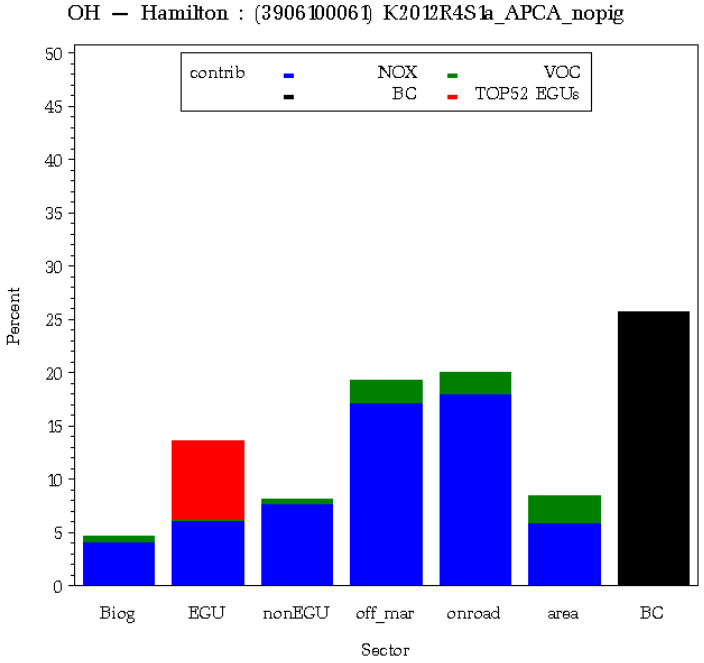
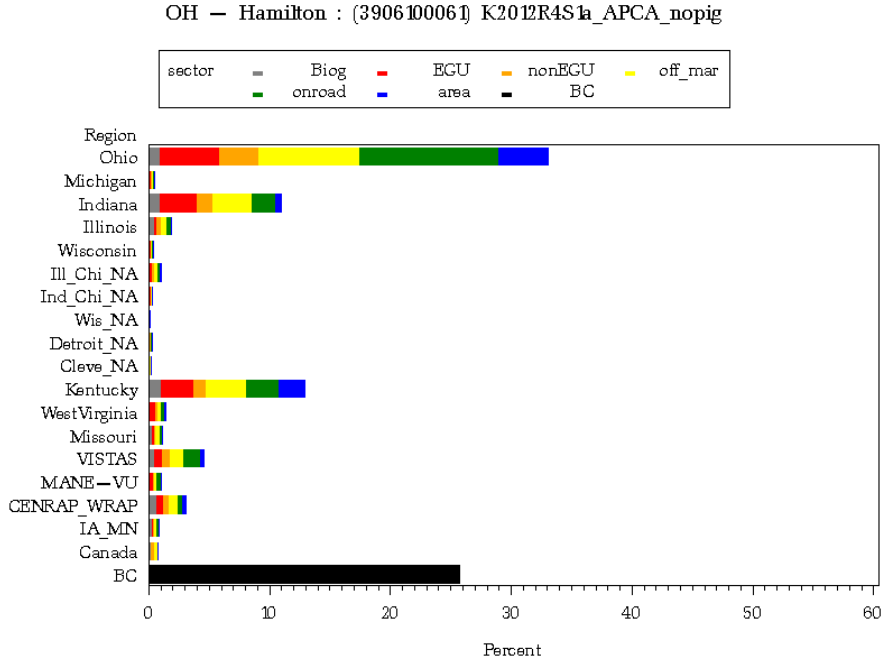
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Hamilton : (3906100061) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Hamilton : (3906100061) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Hamilton : (3906100061) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Hamilton : (3906100061) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
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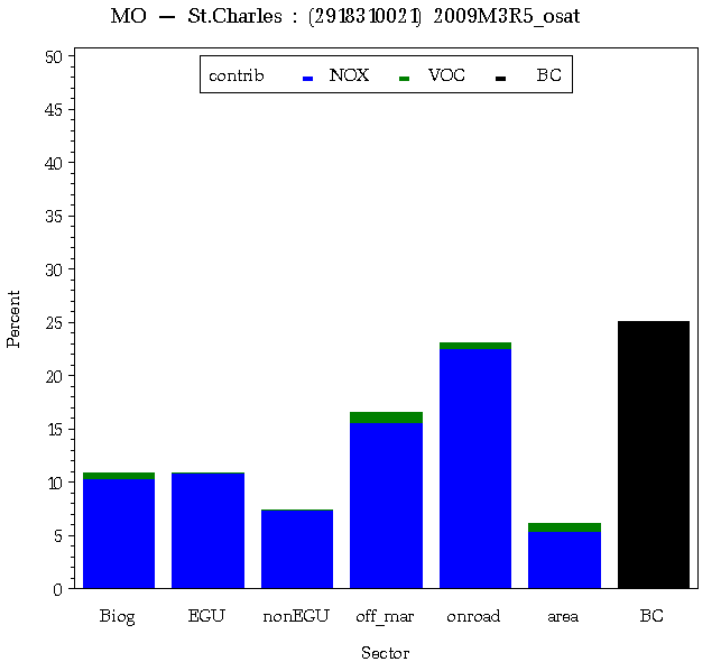
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


MO — St.Charles : (291831002 1) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
0
5
10
15
20
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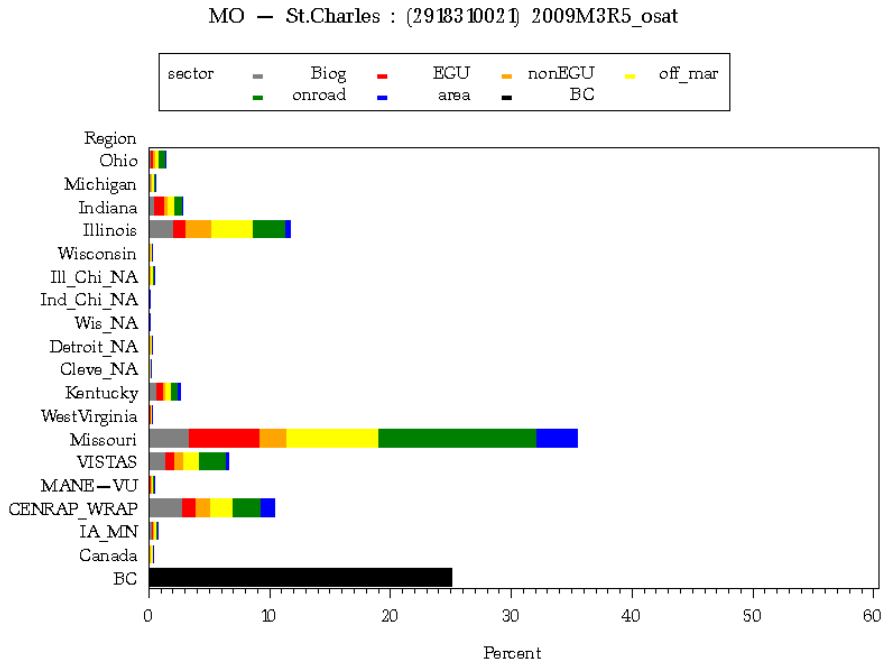
30
35
40
45
50
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


MO — St.Charles : (291831002 1) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
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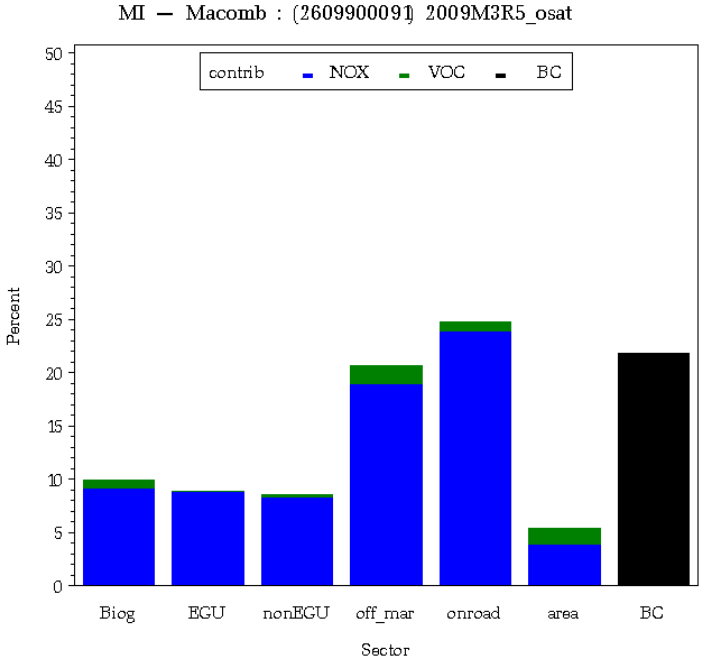
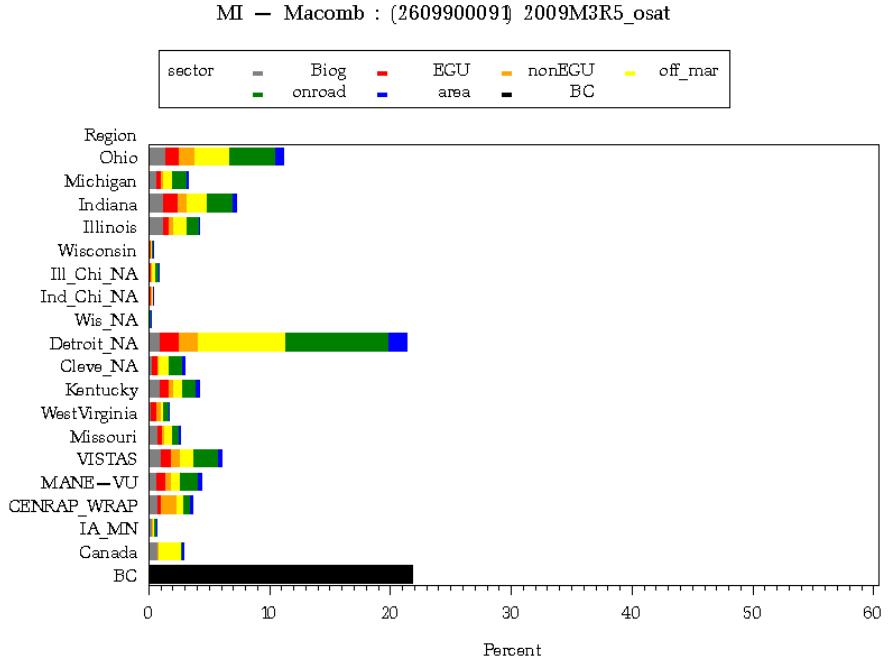
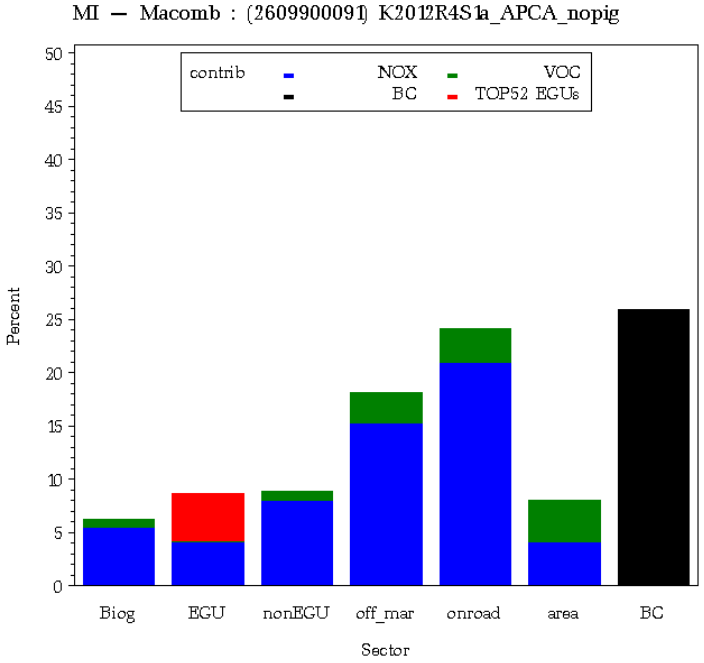
CENRAP_WRAP
IA_MN
Canada
BC
0
10
20
30
40
50
60
Percent


MI — Macomb : (2609900091) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Macomb : (2609900091) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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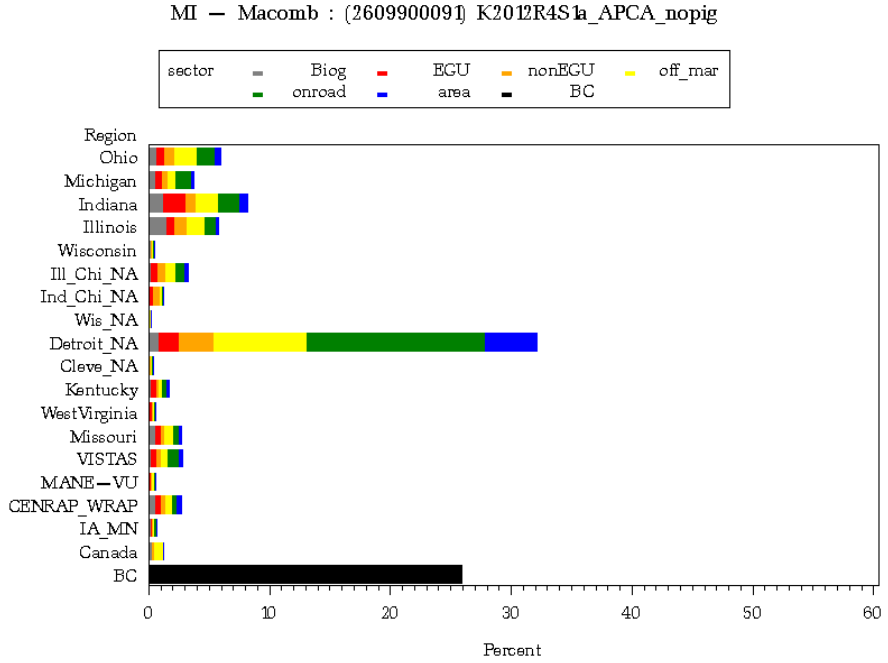
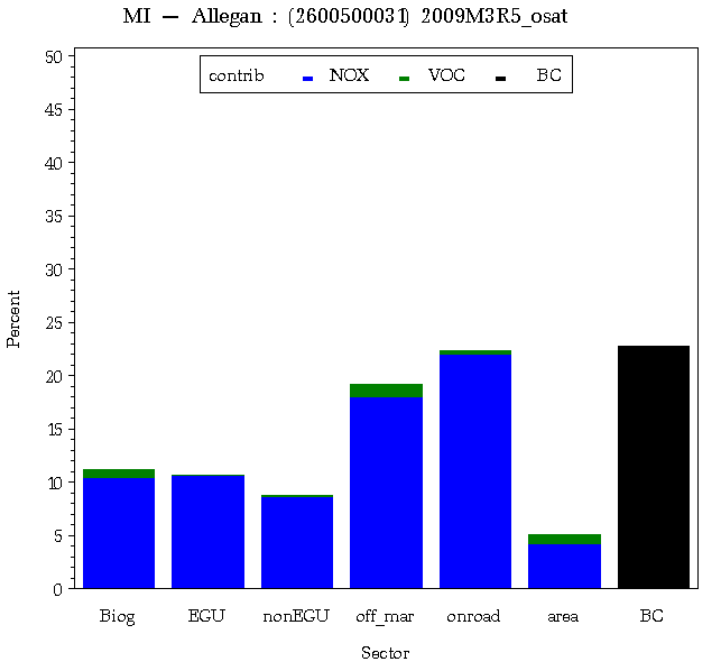
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Macomb : (2609900091) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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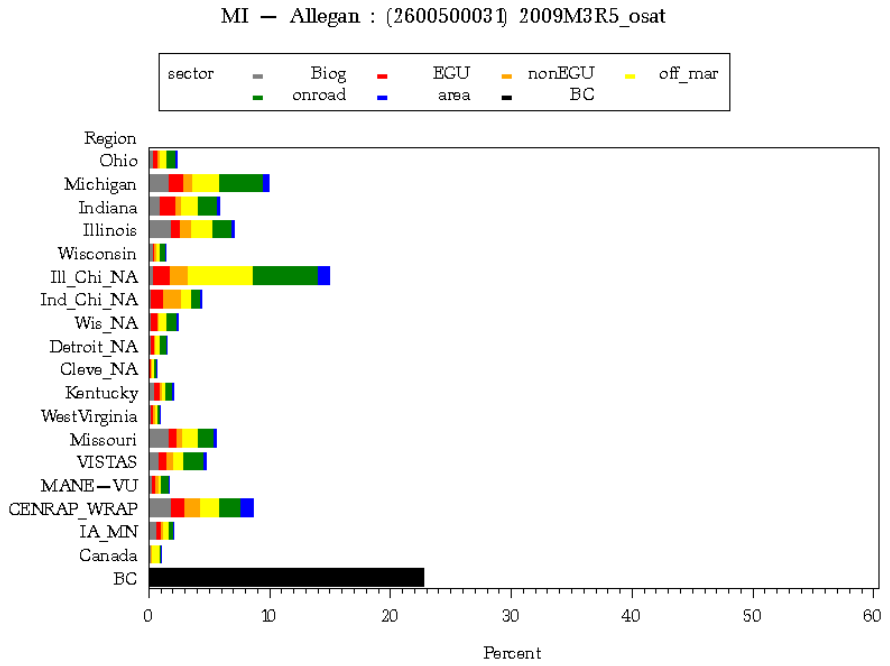
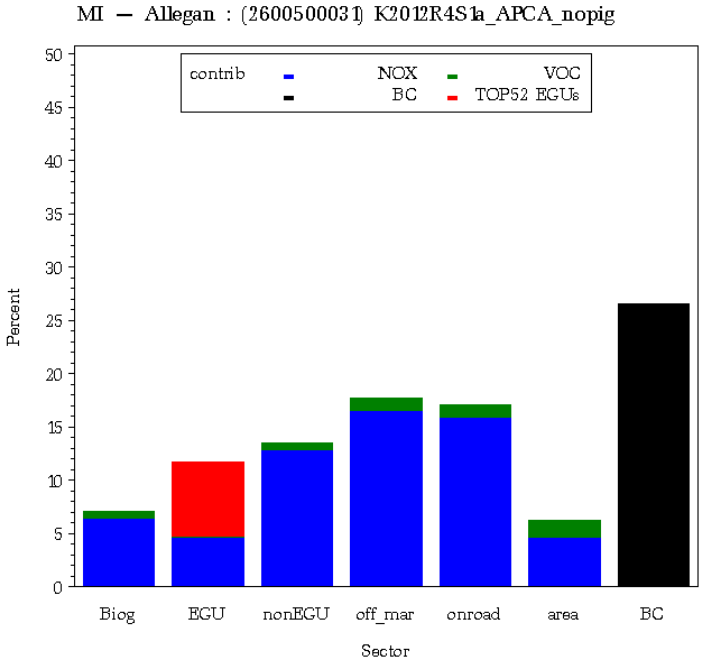
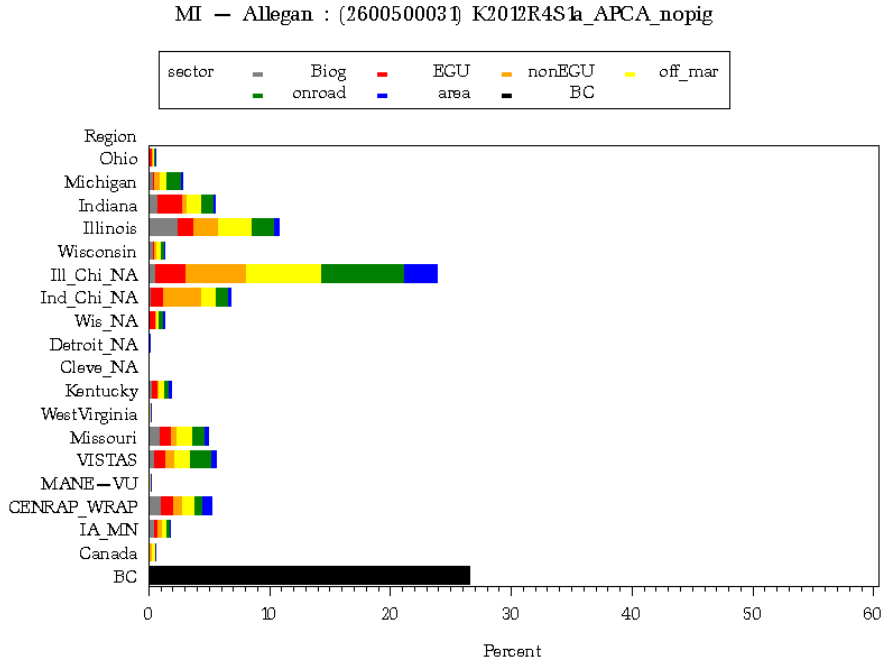
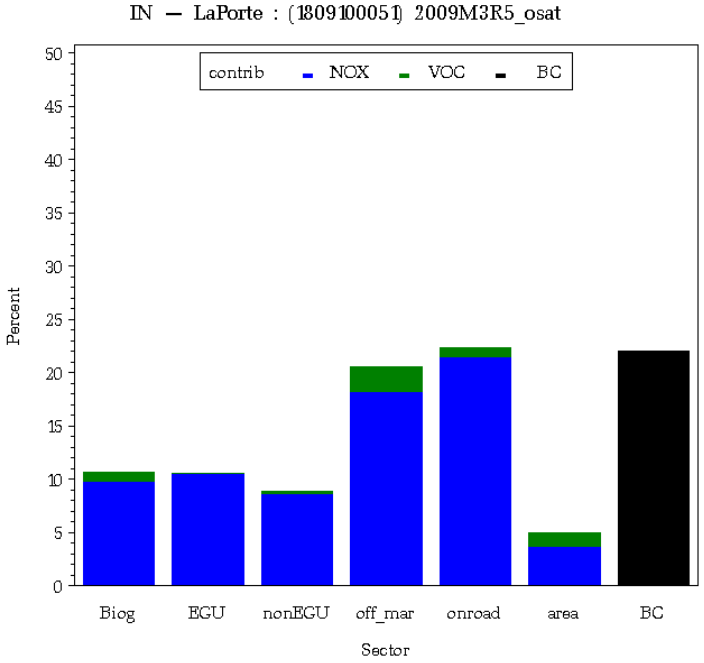
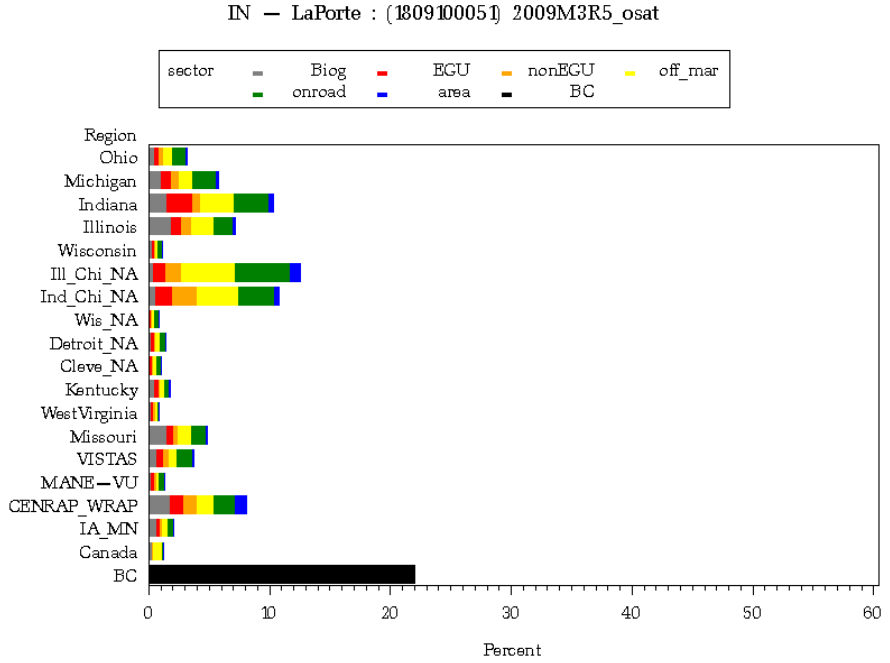
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Allegan : (2600500031) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


MI — Allegan : (2600500031) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Allegan : (2600500031) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — LaPorte : (180910005 1) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — LaPorte : (180910005 1) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
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WestVirginia
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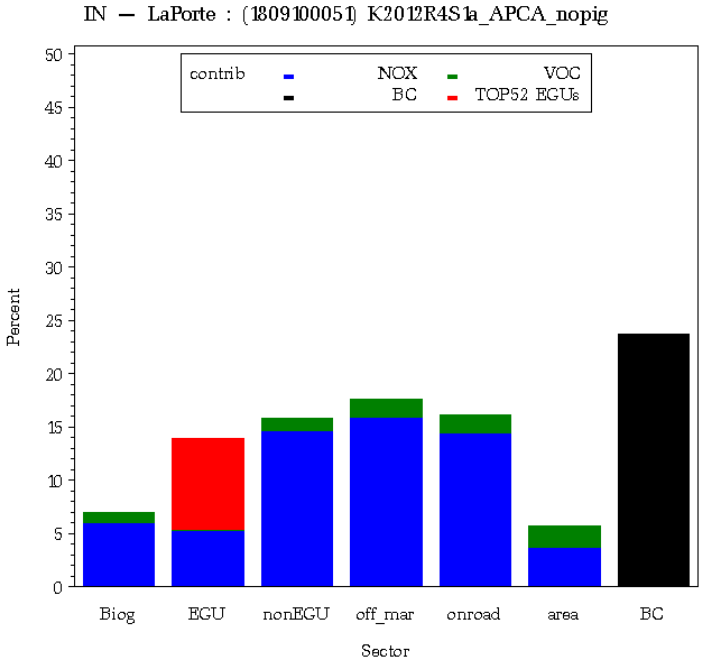
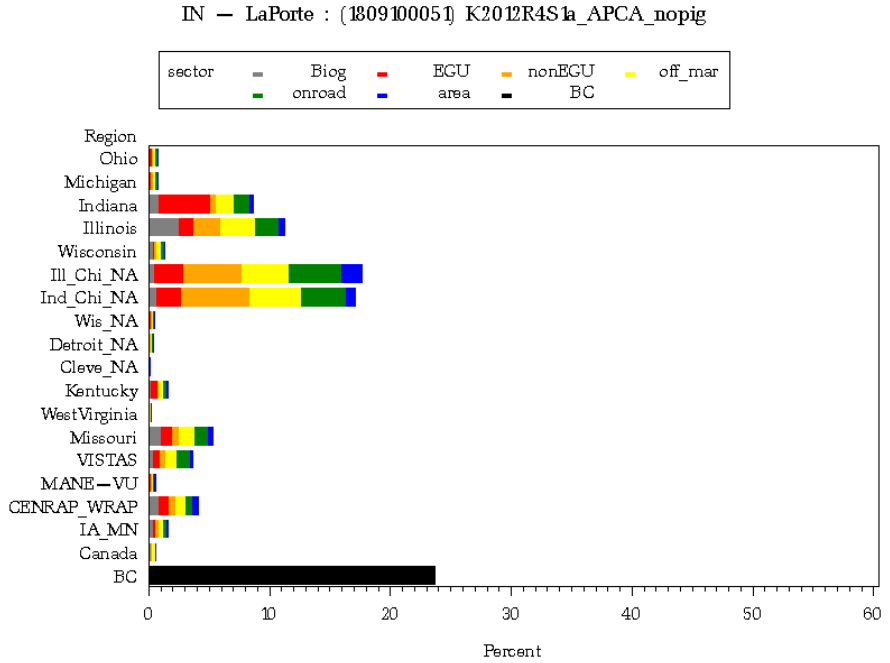
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — LaPorte : (180910005 1) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — LaPorte : (180910005 1) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
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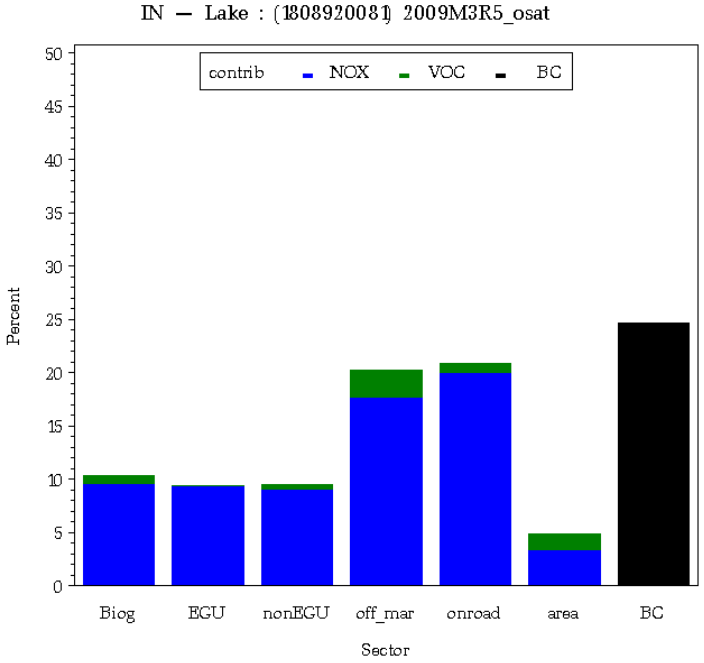
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — Lake : (1808920081) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
0
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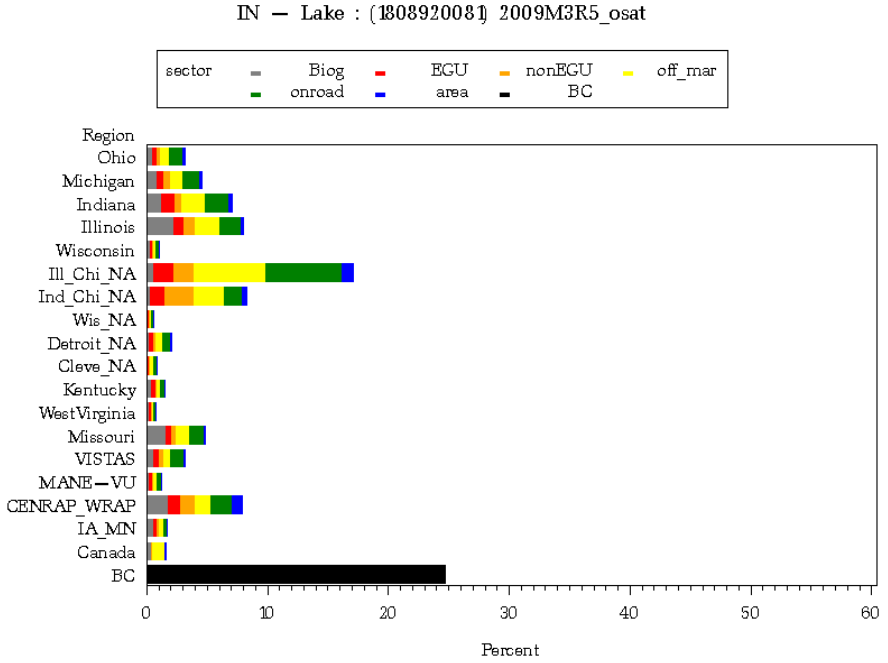
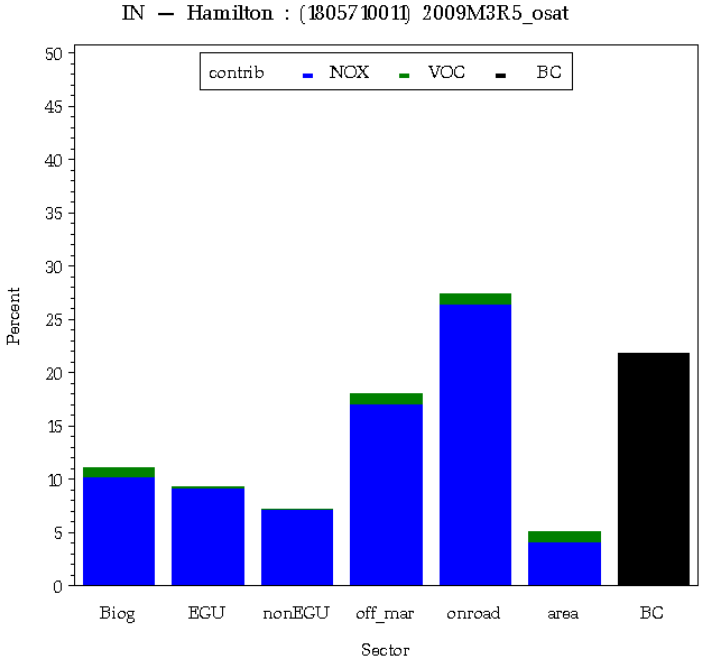
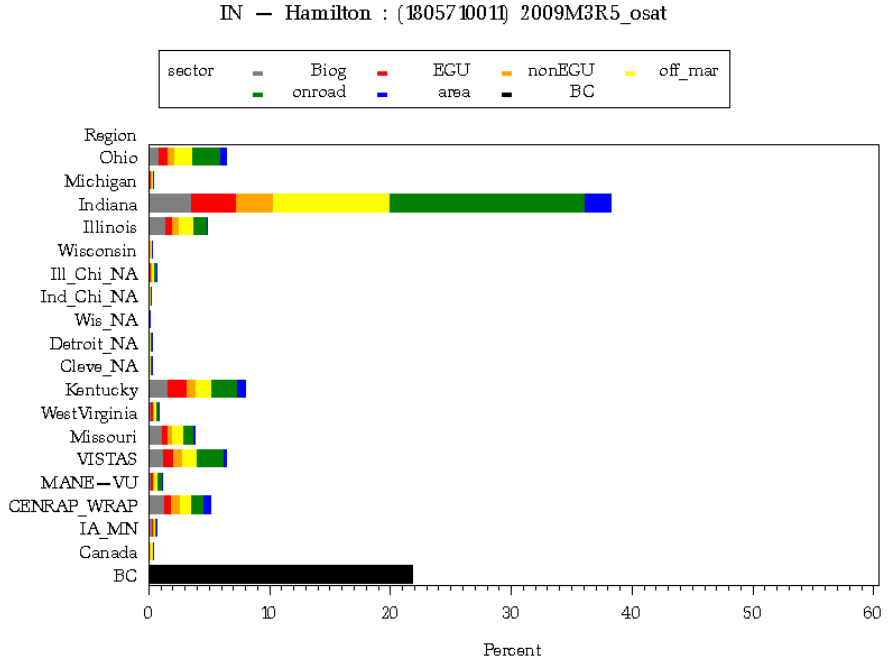
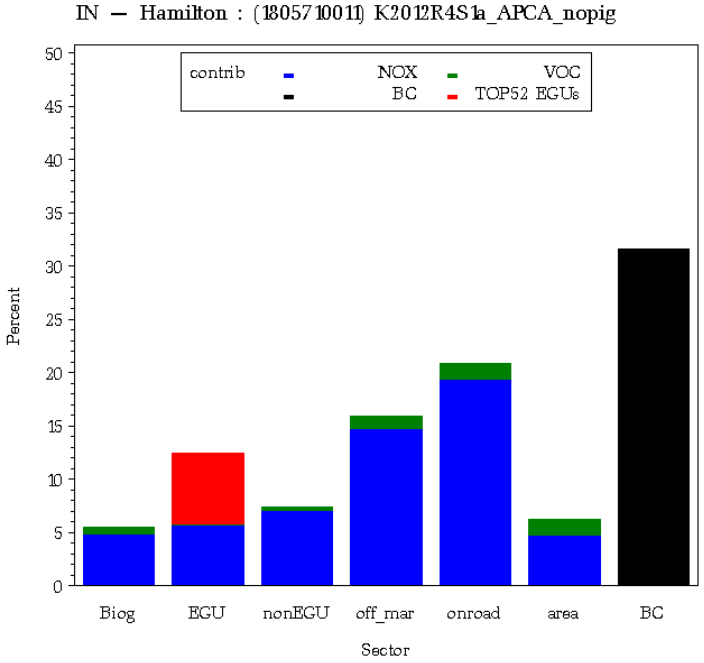
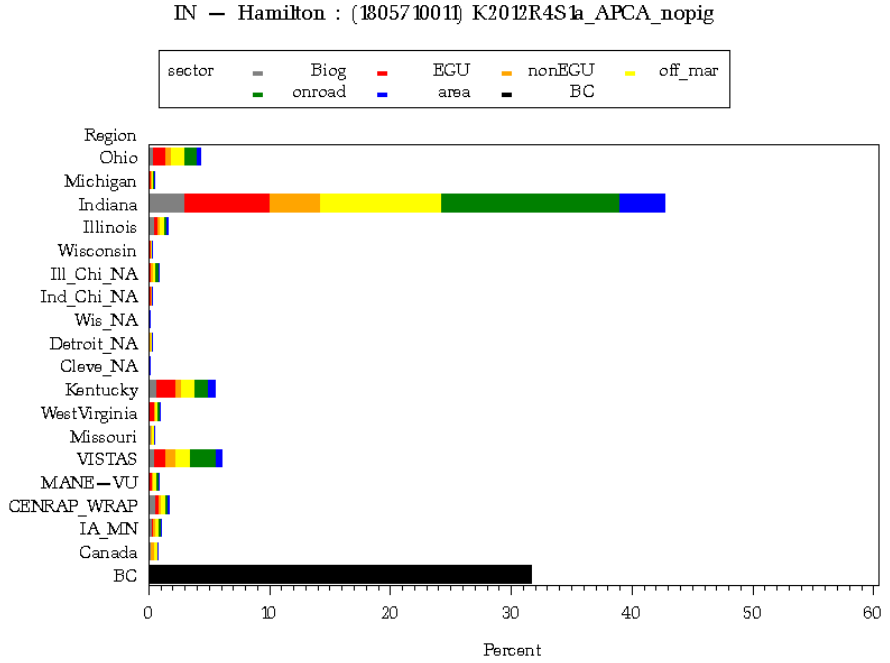
25
30
35
40
45
50
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — Lake : (1808920081) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0
10
20
30
40
50
60
Percent


IN — Hamilton : (180571011) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — Hamilton : (180571011) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — Hamilton : (180571011) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector

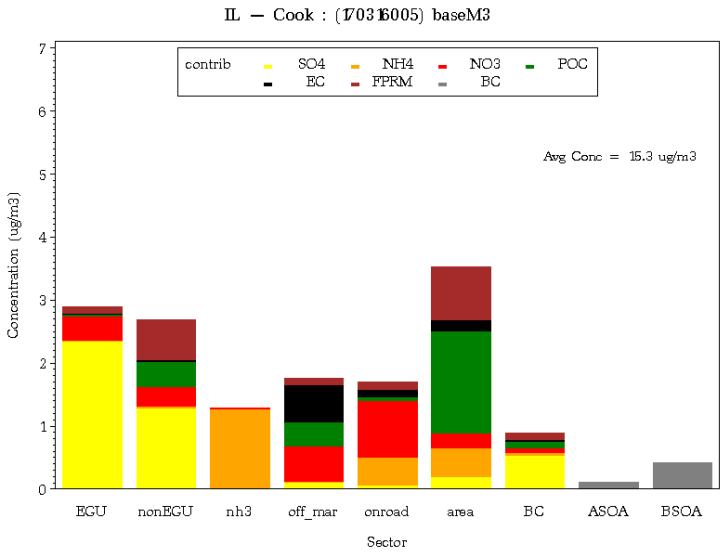

IN — Hamilton : (180571011) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

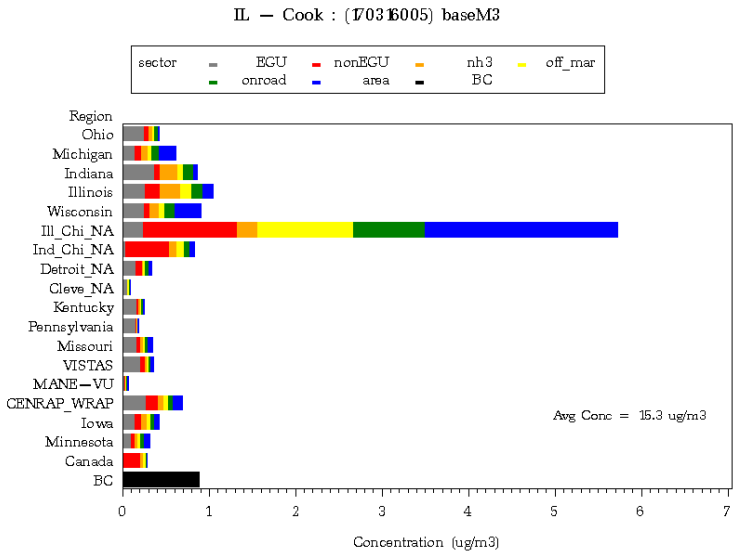
APPENDIX III

$PM_{2.5}$ Source Apportionment Modeling Results

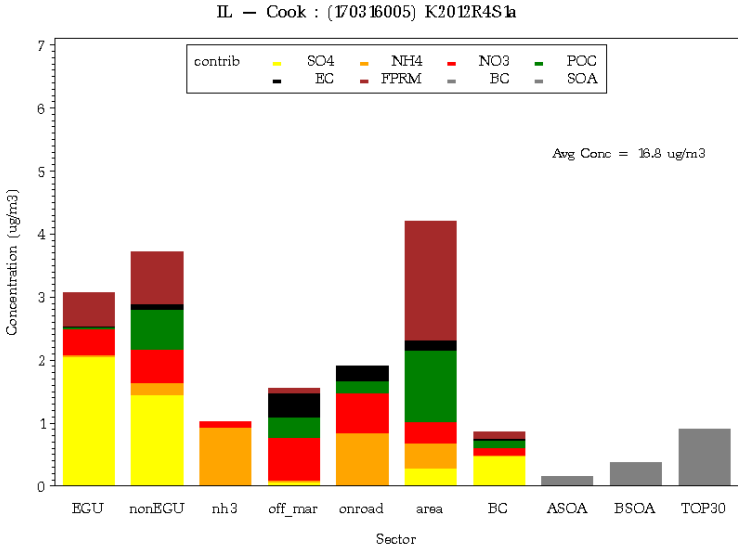
Chicago (Cicero), Illinois

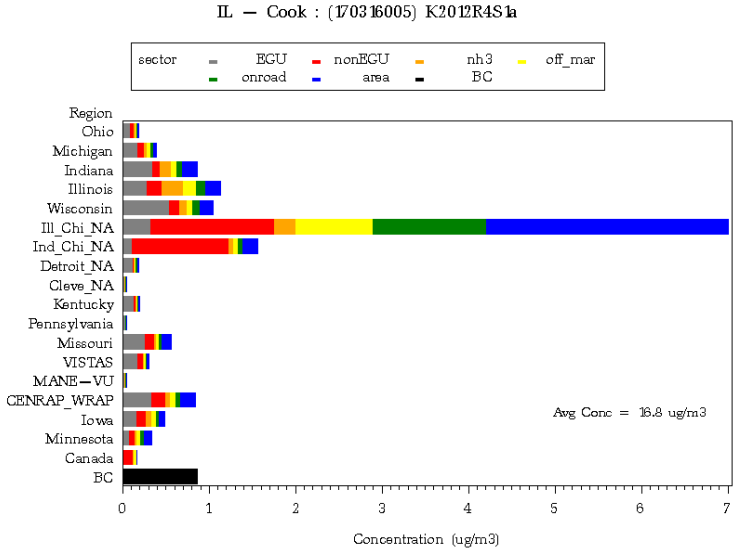
2005 (Round 5)



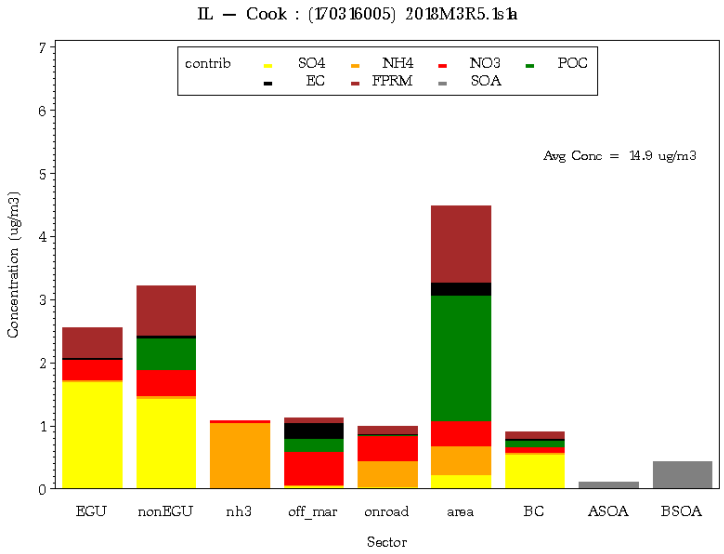


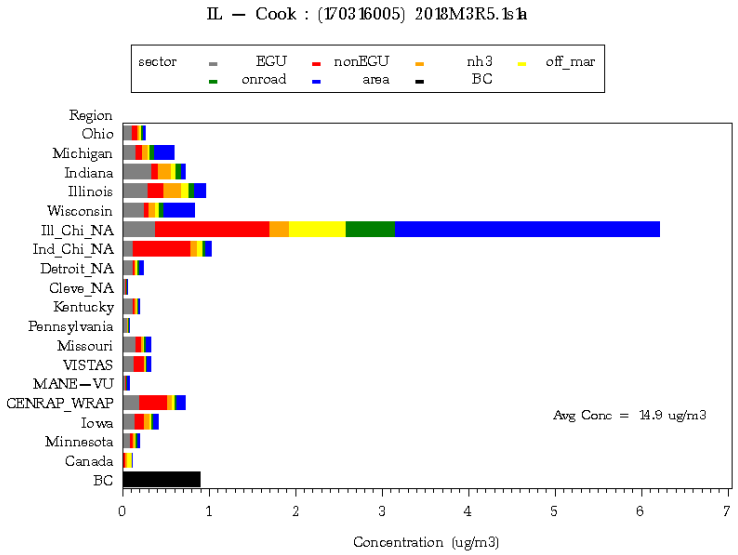
2012 (Round 4)





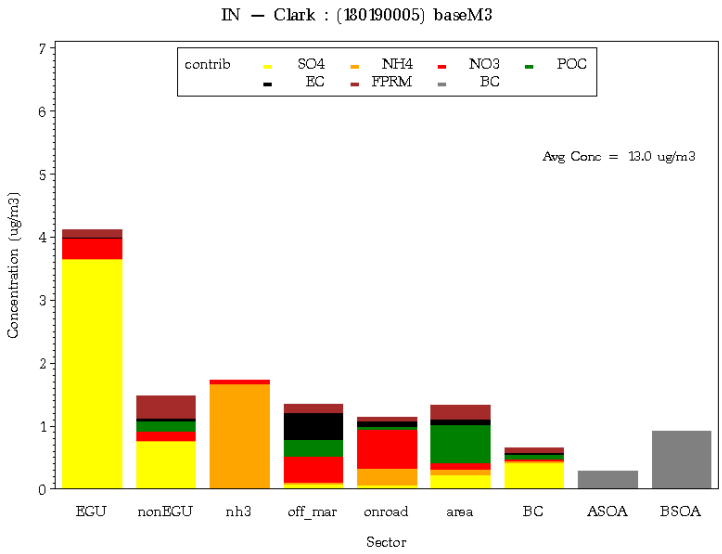
2018 (Round 5)

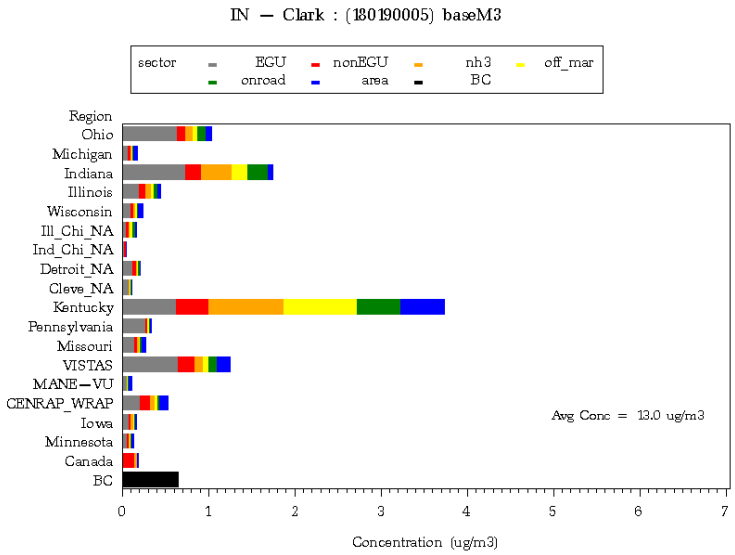




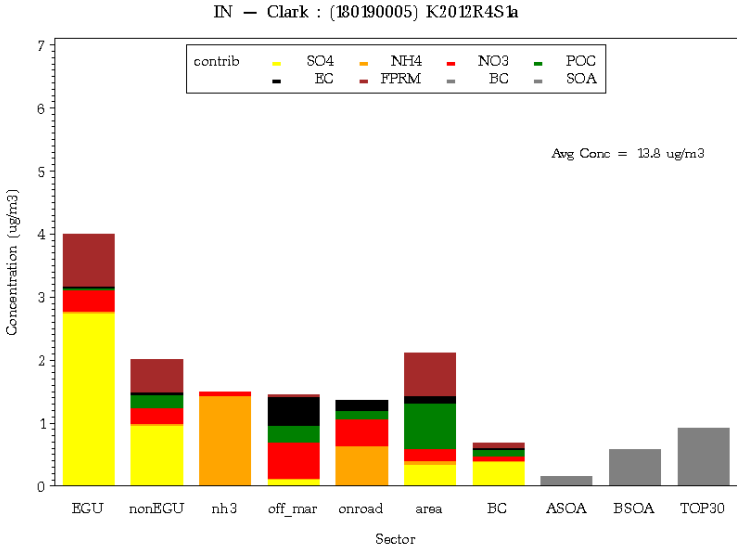
Clark County, Indiana

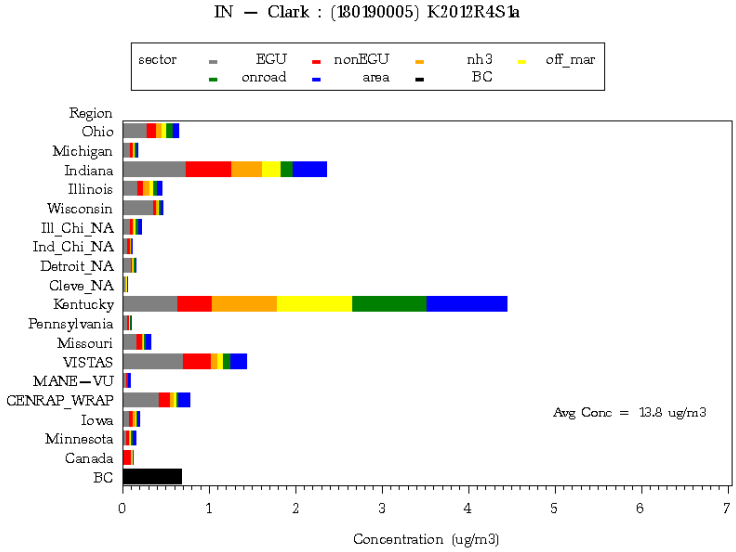
2005 (Round 5)



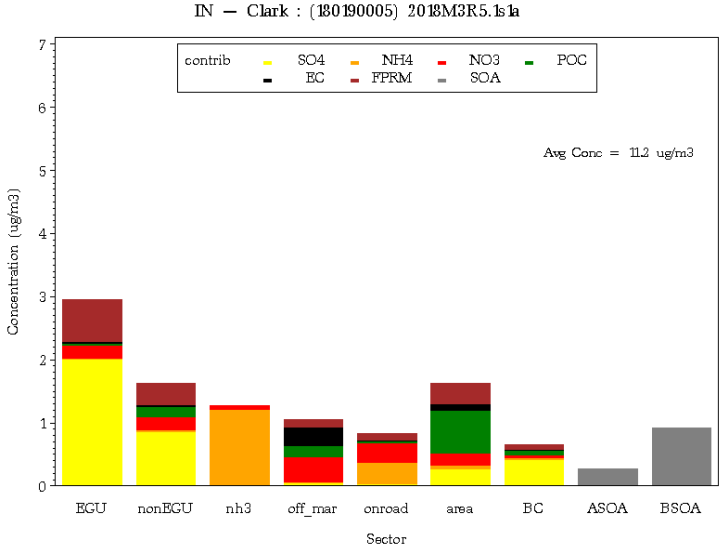


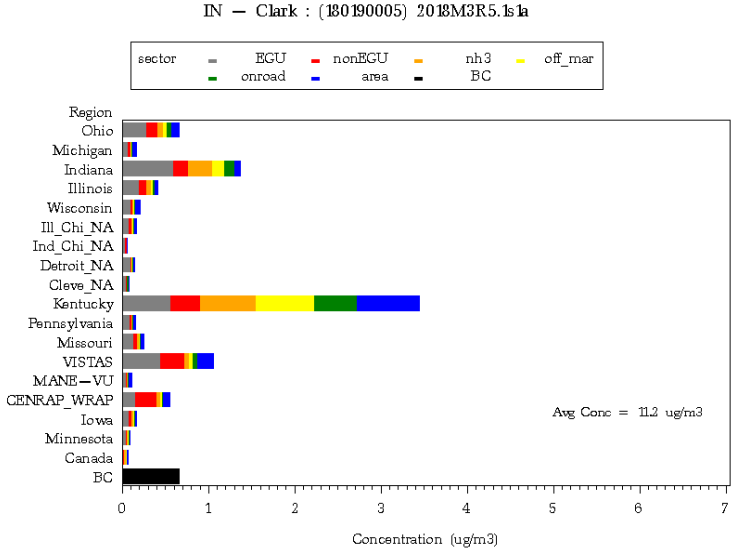
2012 (Round 4)





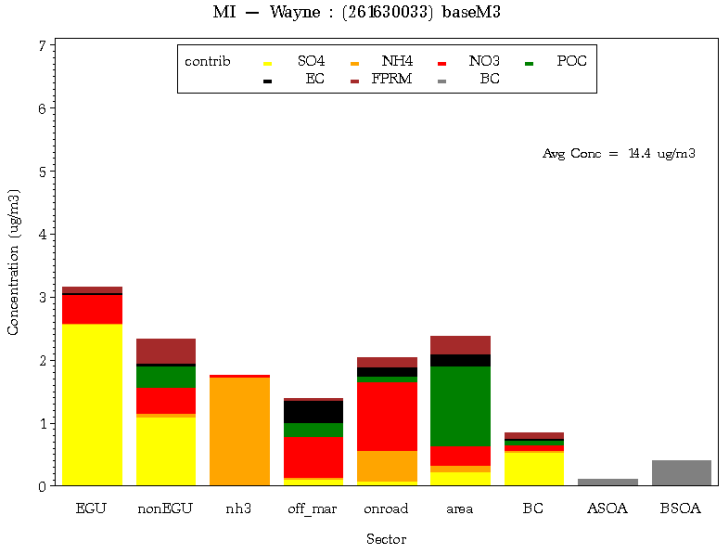
2018 (Round 5)

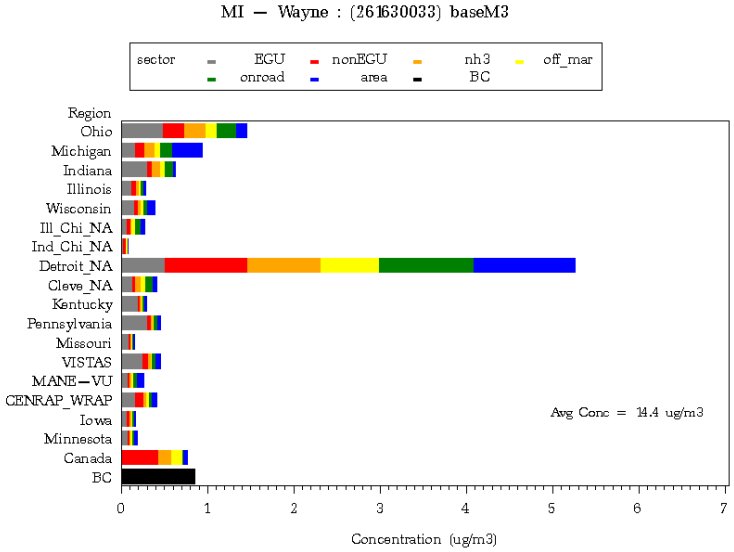




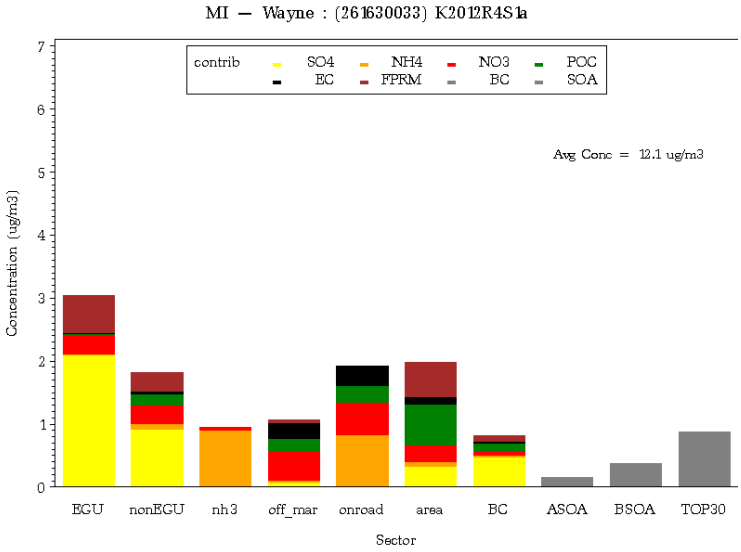
Dearborn, Michigan

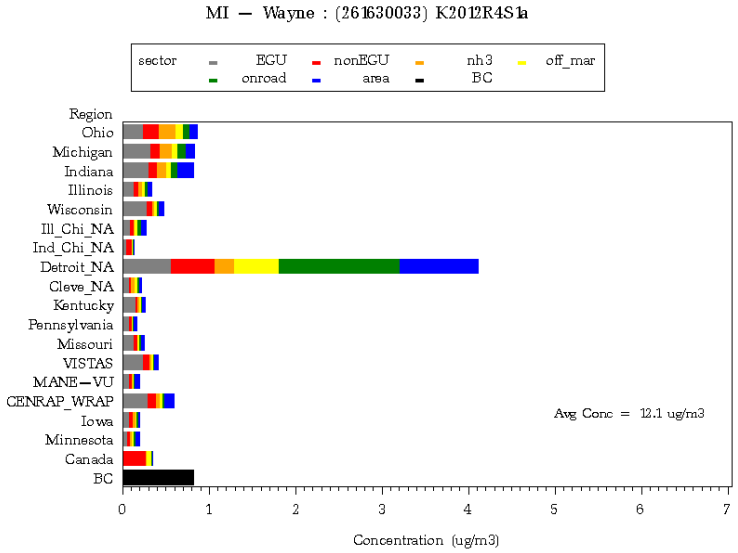
2005 (Round 5)



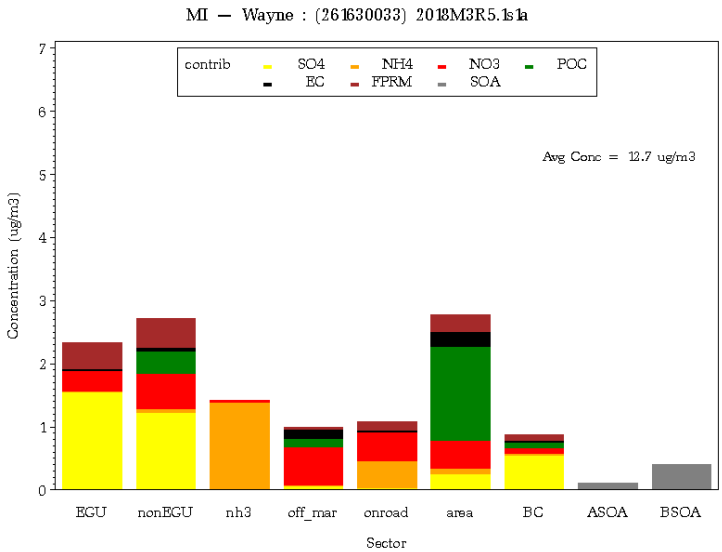


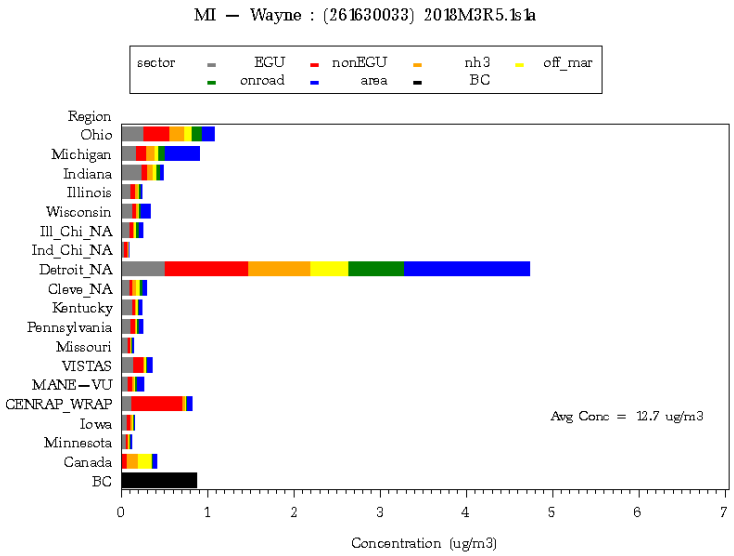
2012 (Round 4)





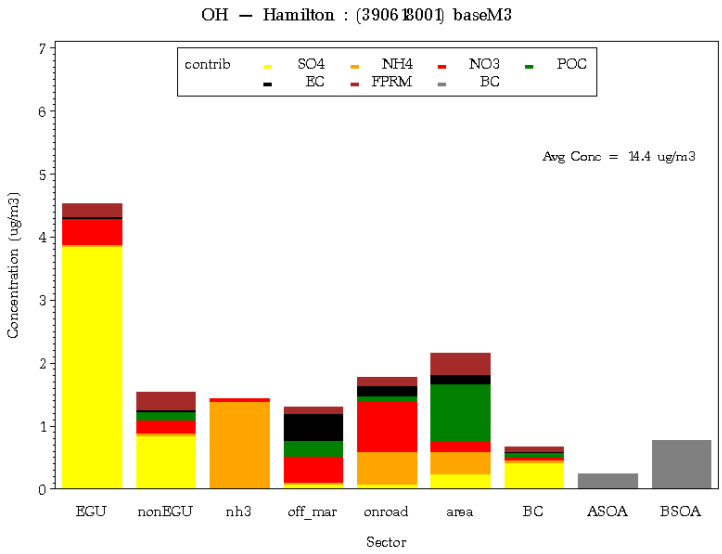
2018 (Round 5)

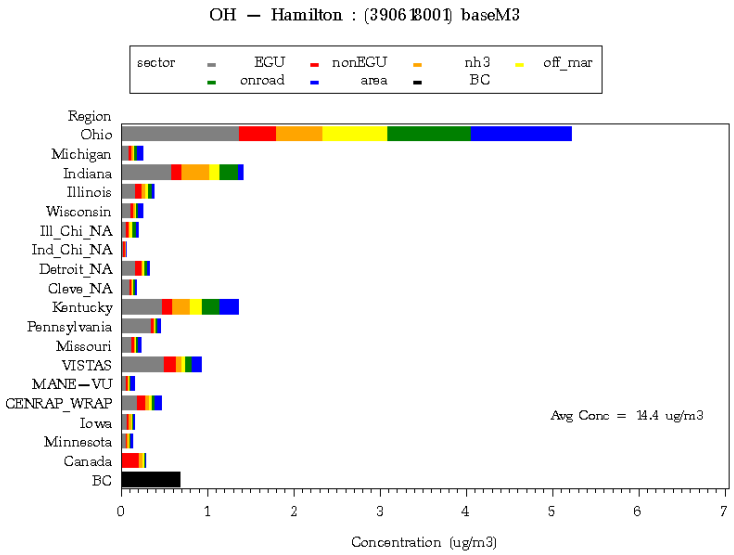




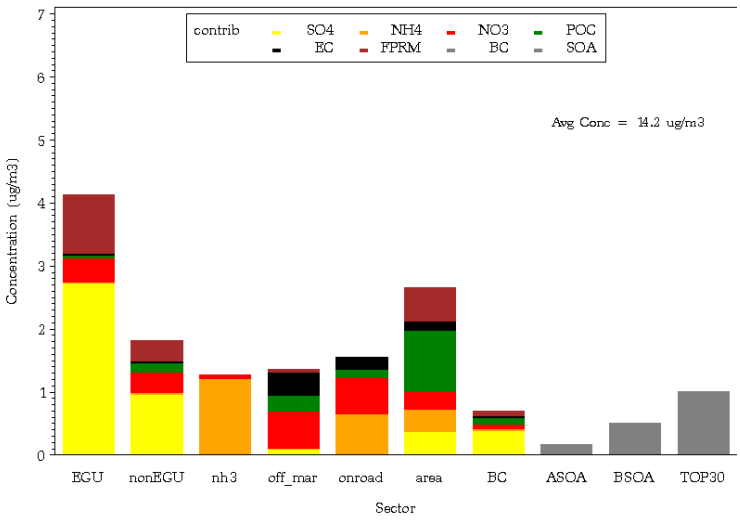
Cincinnati, Ohio

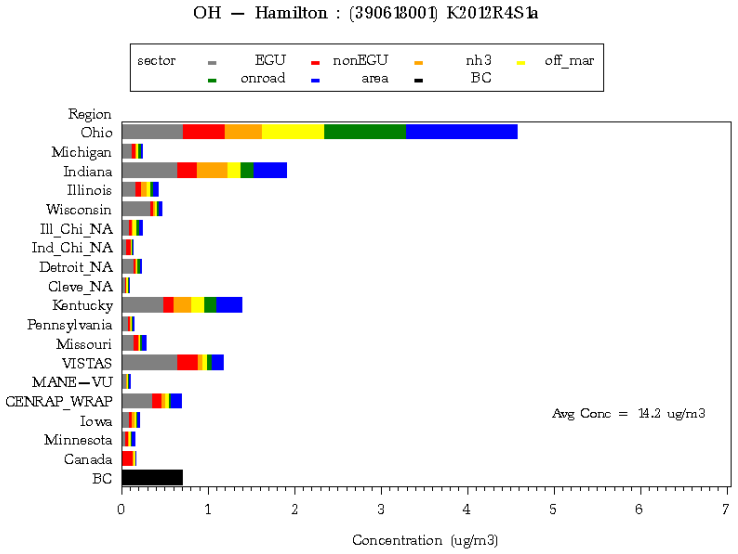
2005 (Round 5)



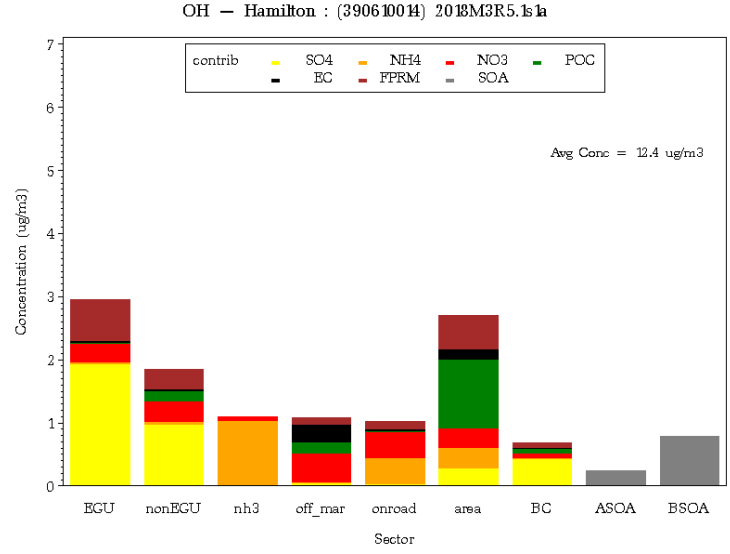


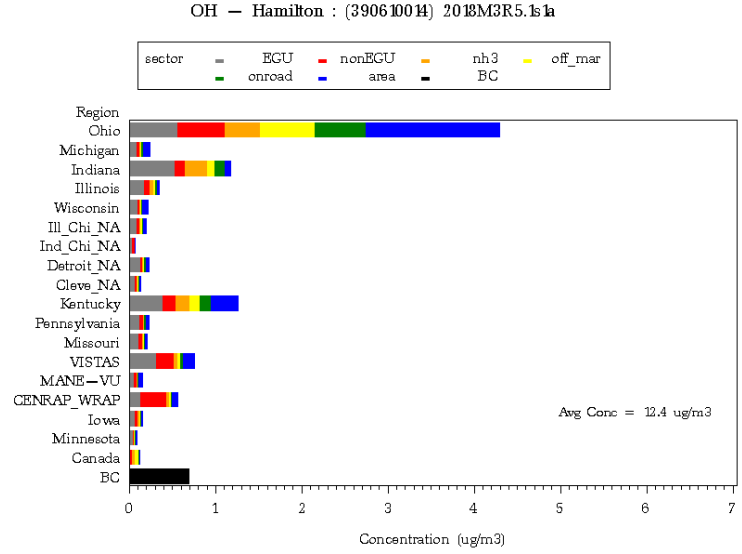
2012 (Round 4)





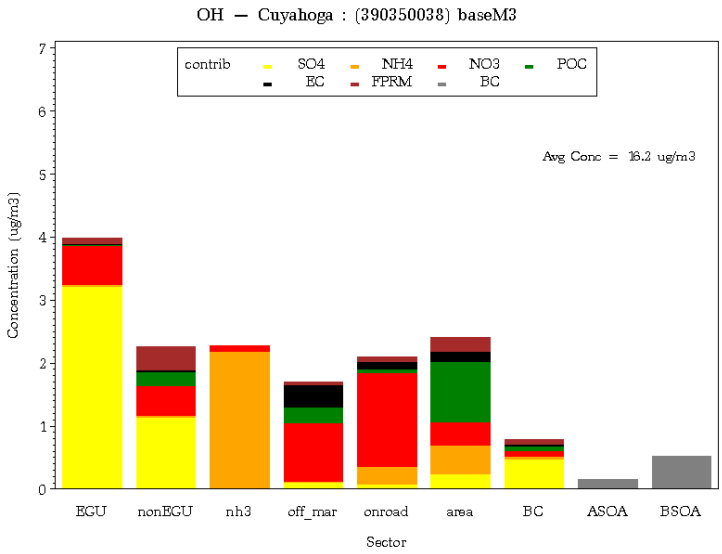
2018 (Round 5)

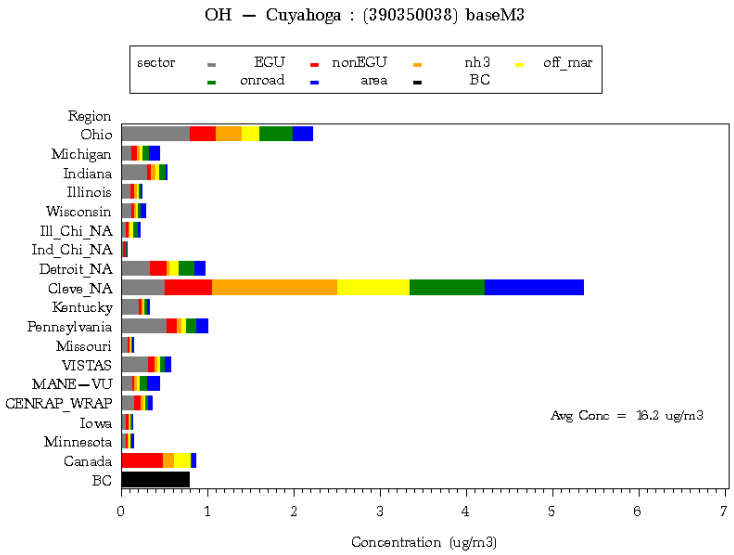




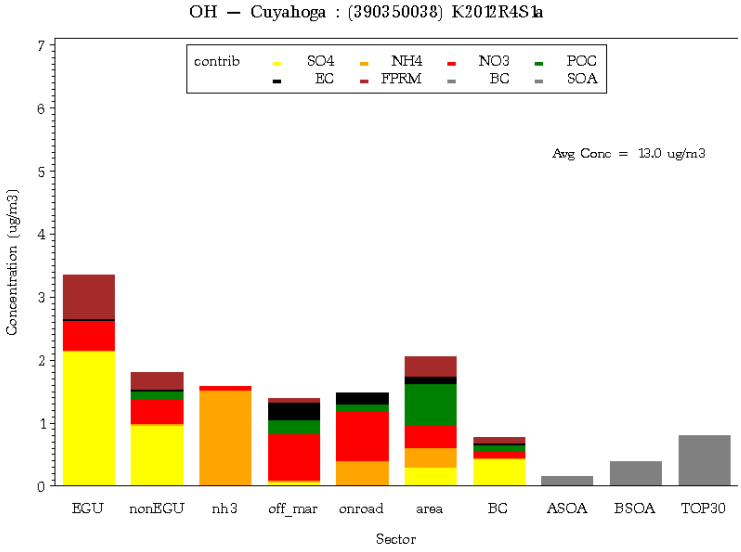
Cleveland, Ohio

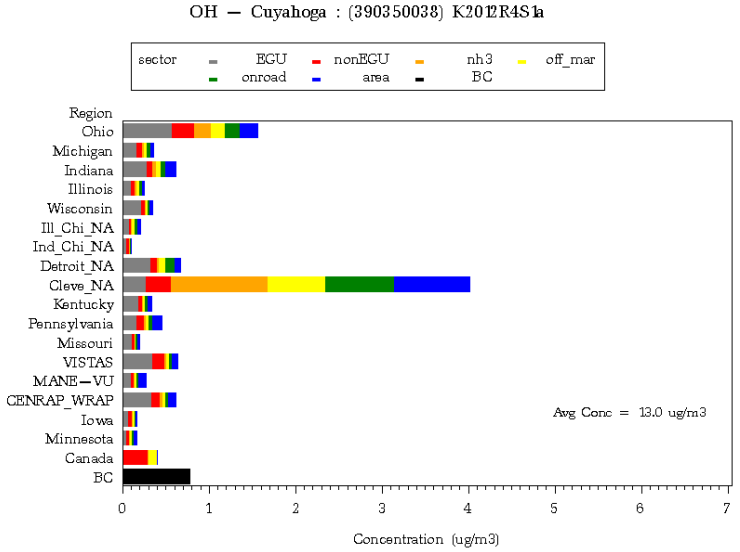
2005 (Round 5)



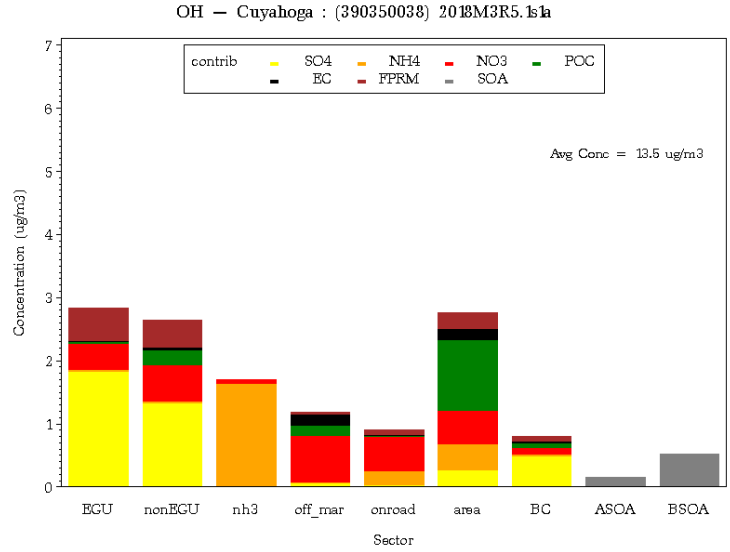


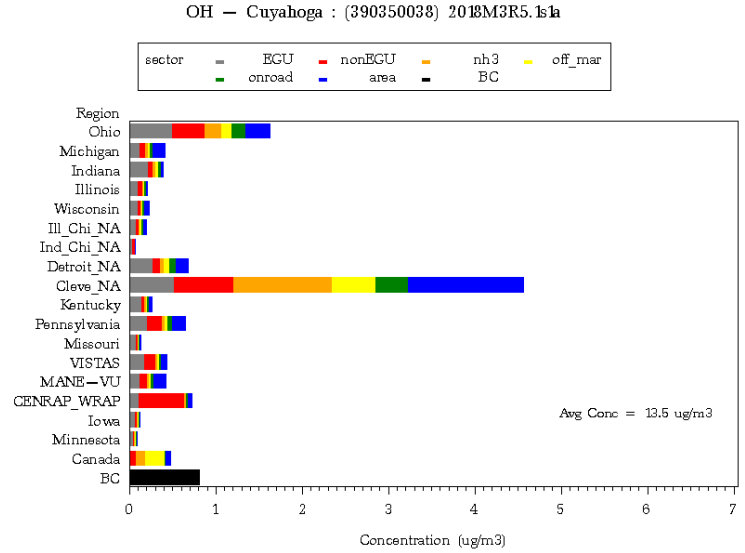
2012 (Round 4)





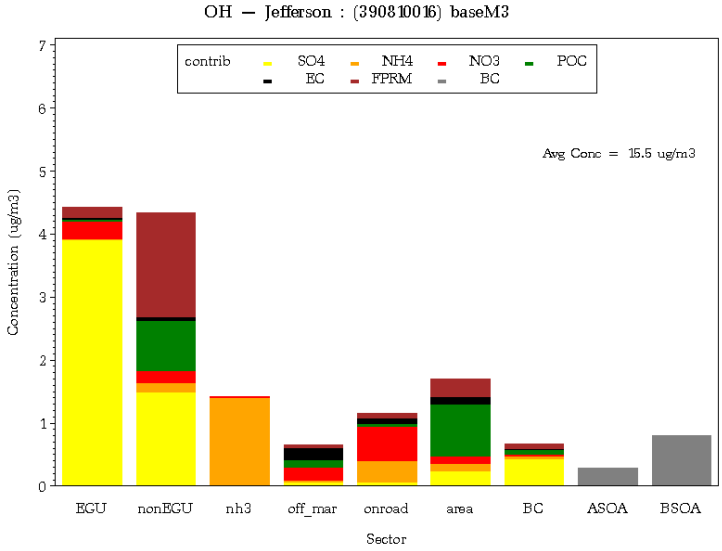
2018 (Round 5)

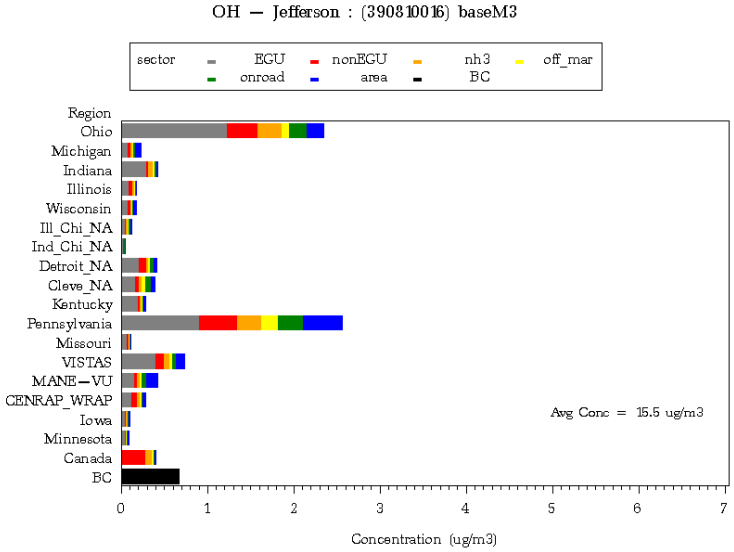




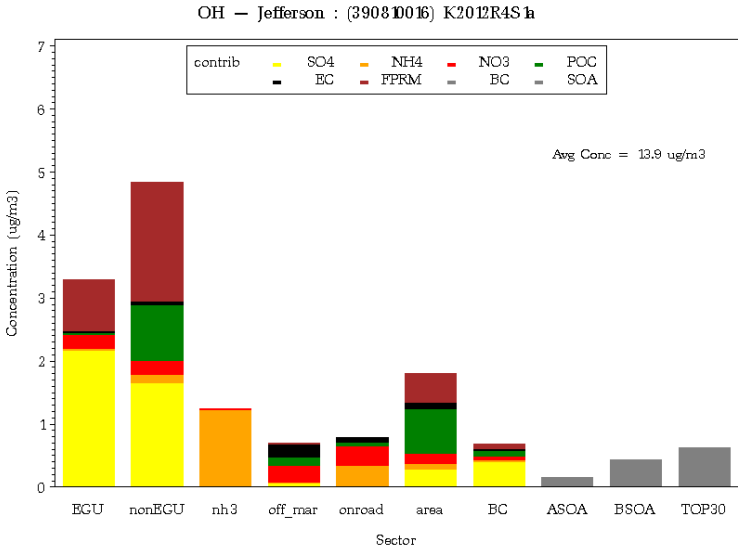
Steubenville, Ohio

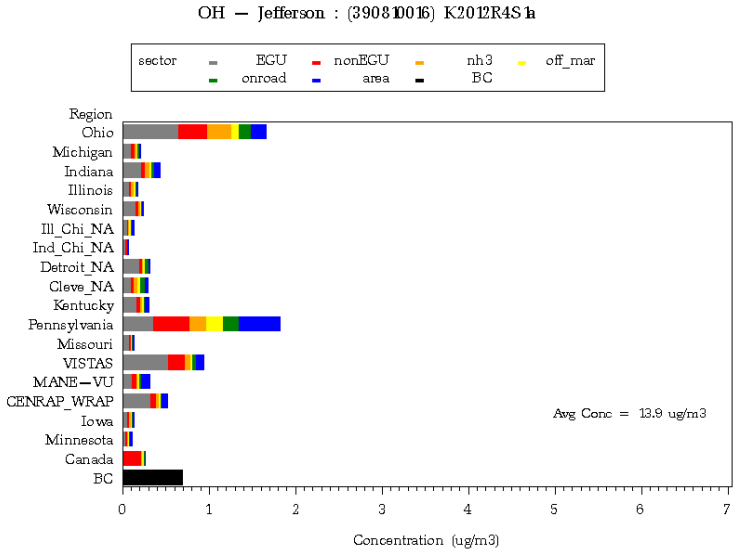
2005 (Round 5)



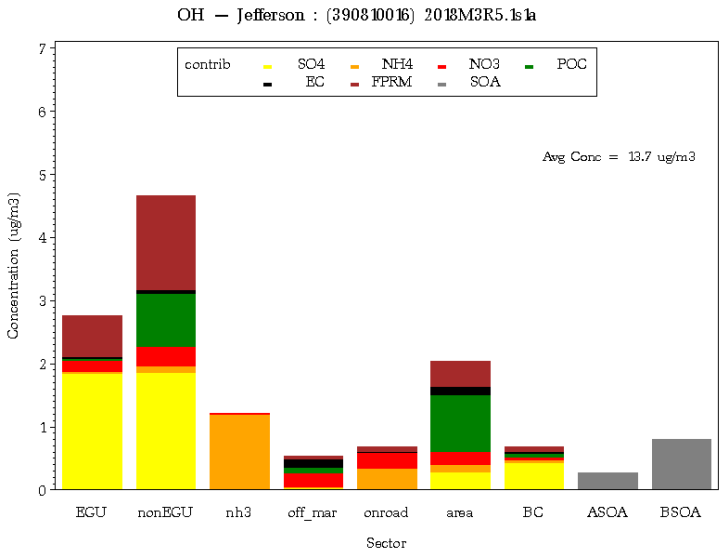


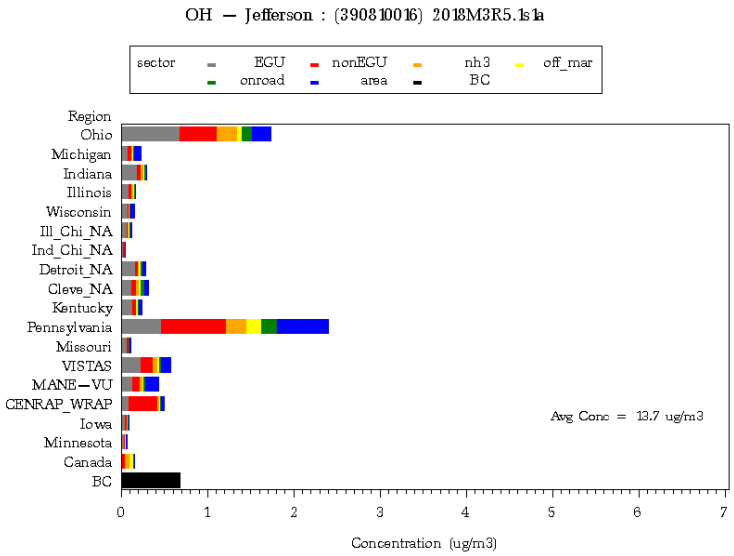
2012 (Round 4)





2018 (Round 5)



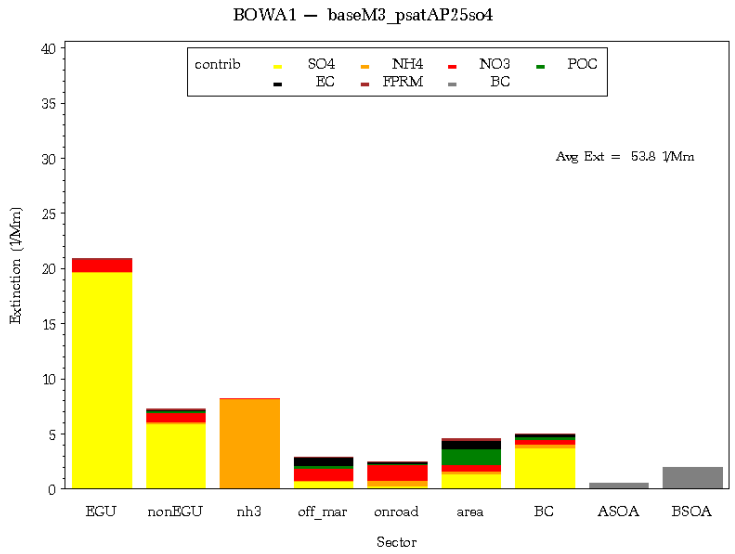


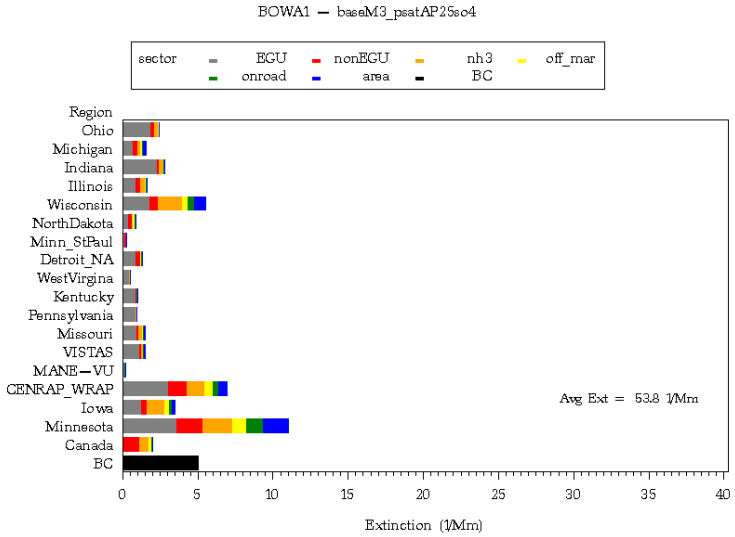
APPENDIX IV

Haze Source Apportionment Modeling Results

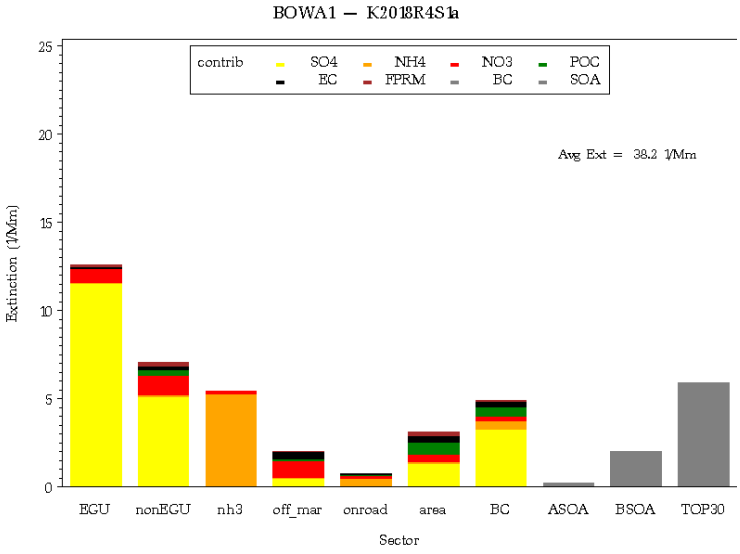
Boundary Waters, Minnesota

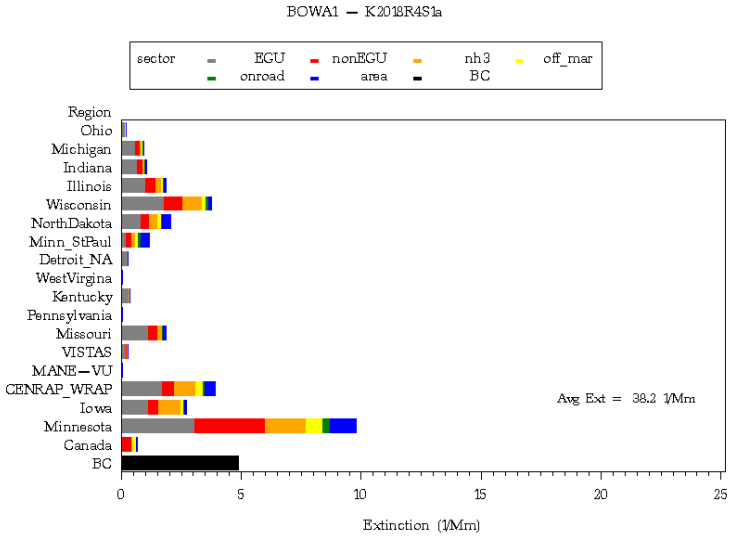
2005 (Round 5)



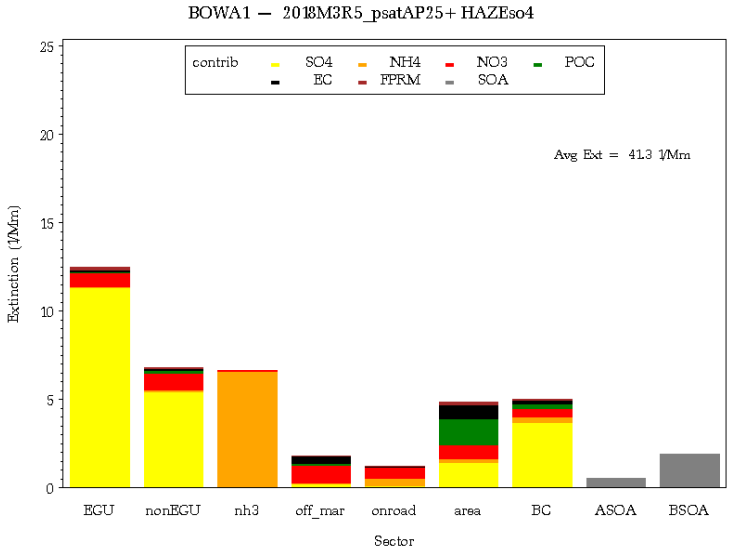


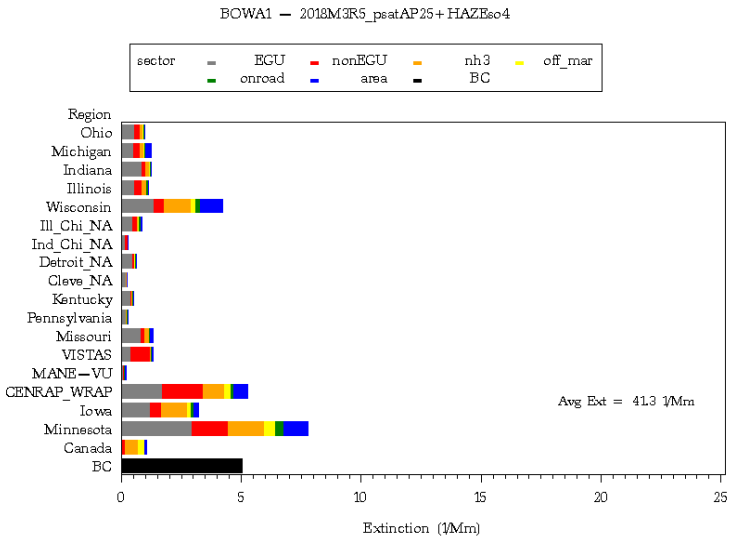
2018 (Round 4)





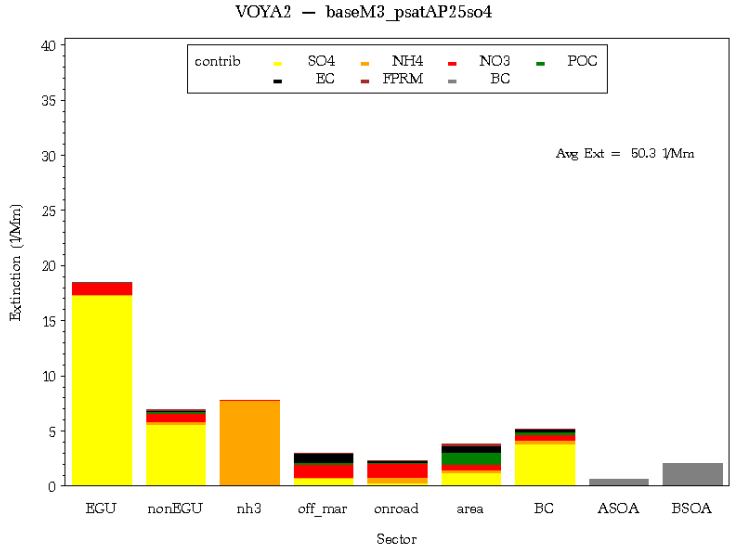
2018 (Round 5)

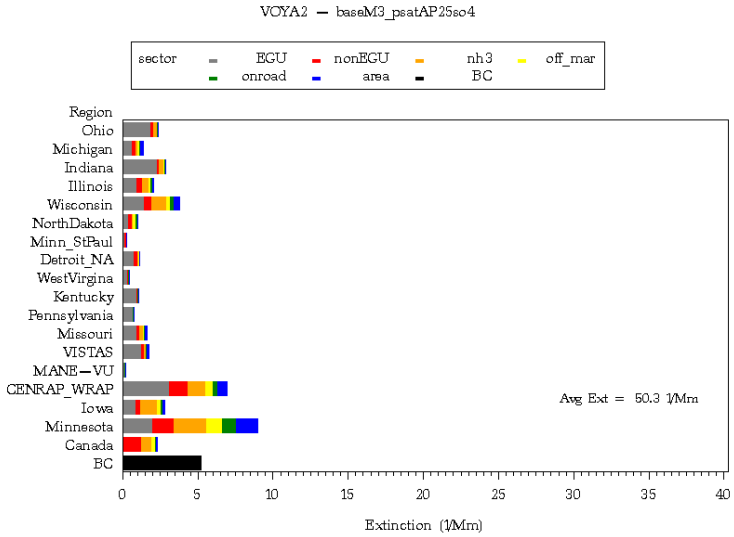




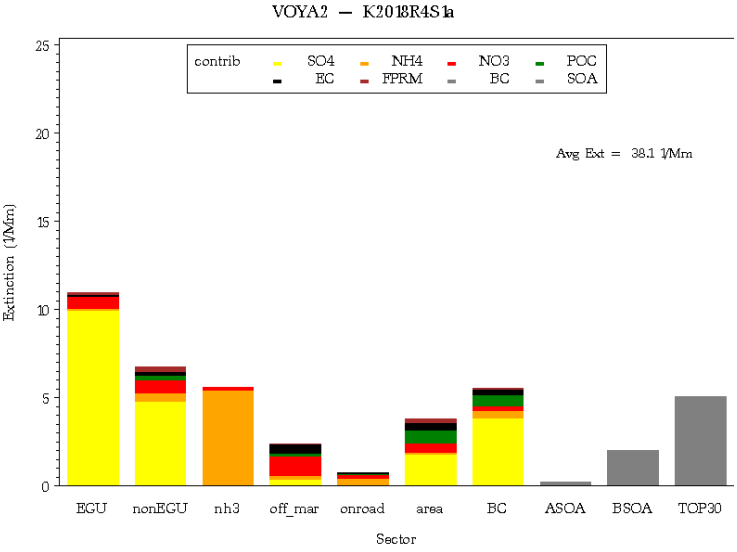
Voyageurs, Minnesota

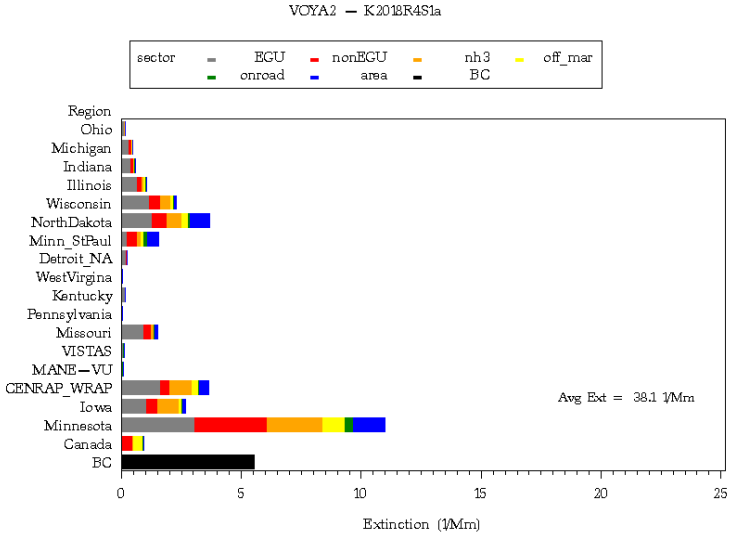
2005 (Round 5)



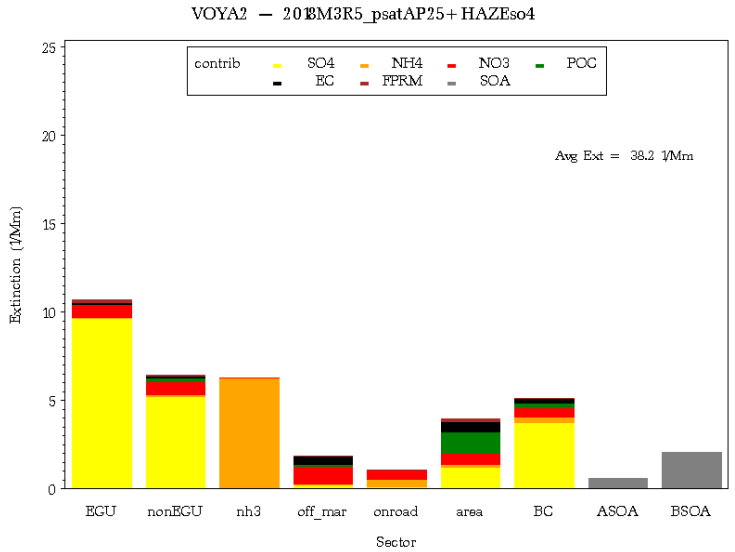


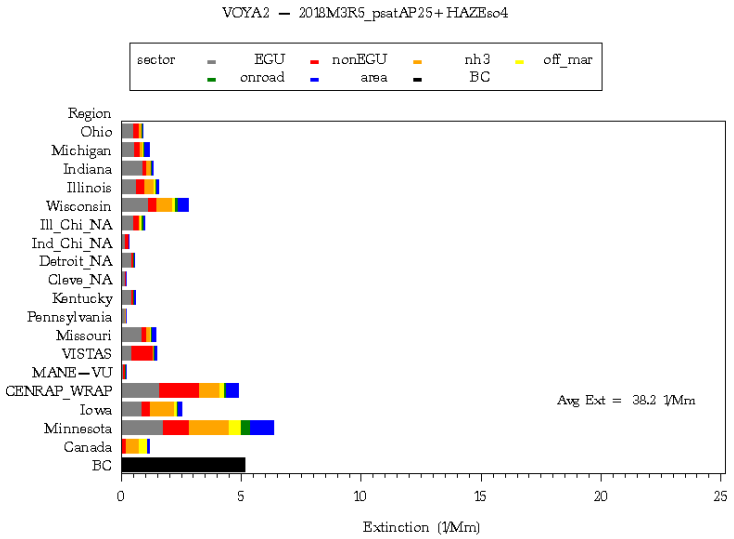
2018 (Round 4)





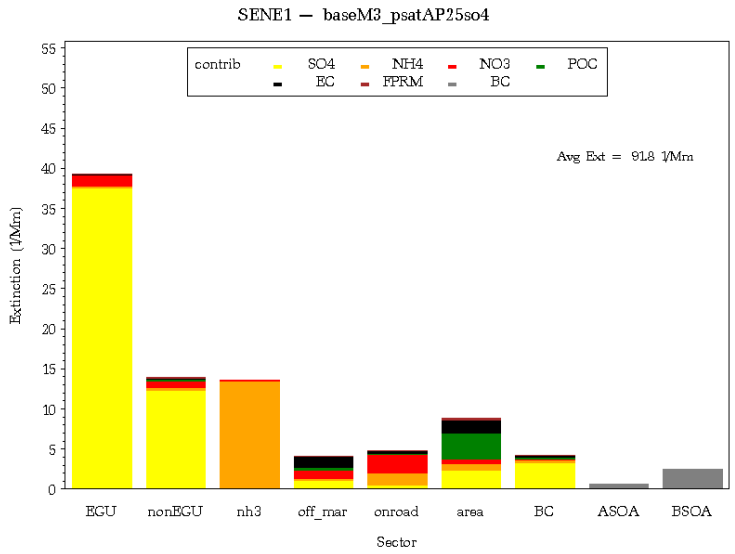
2018 (Round 5)

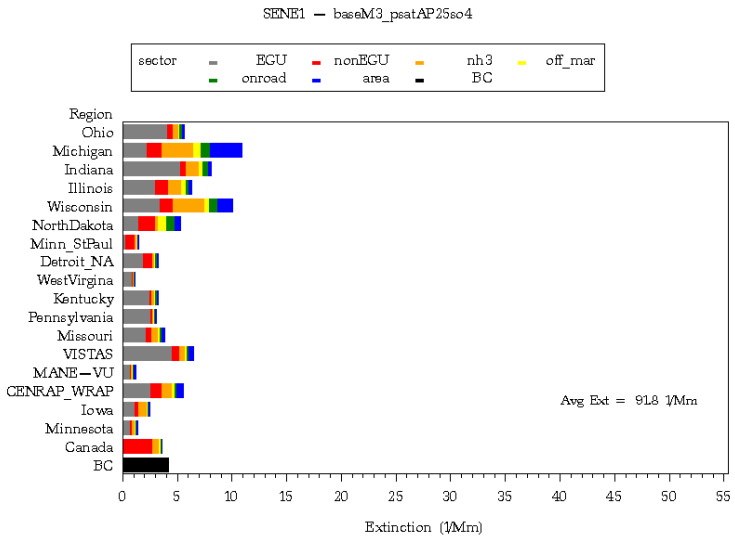




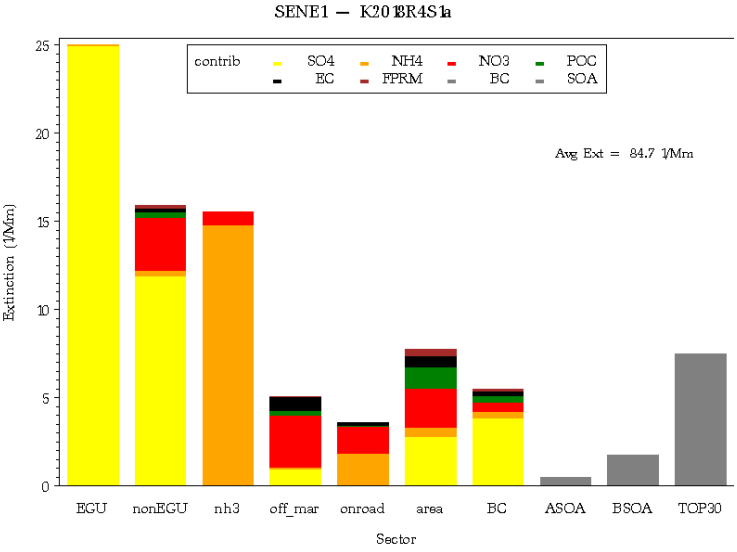
Seney, Michigan

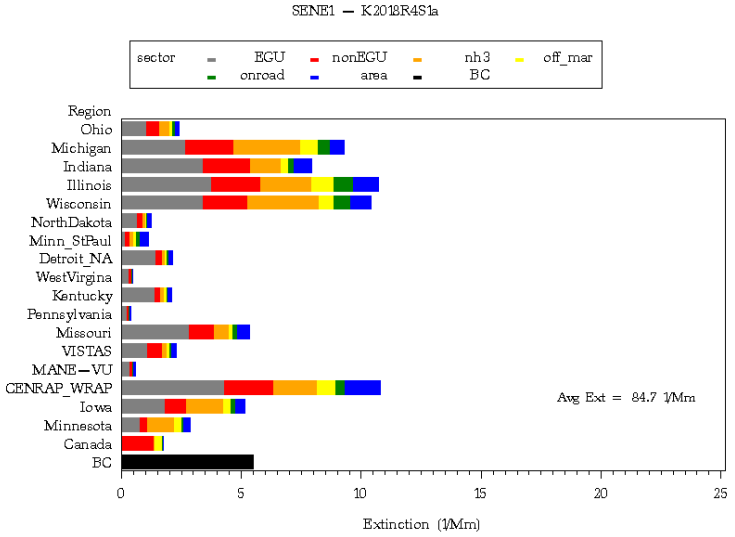
2005 (Round 5)





2018 (Round 4)





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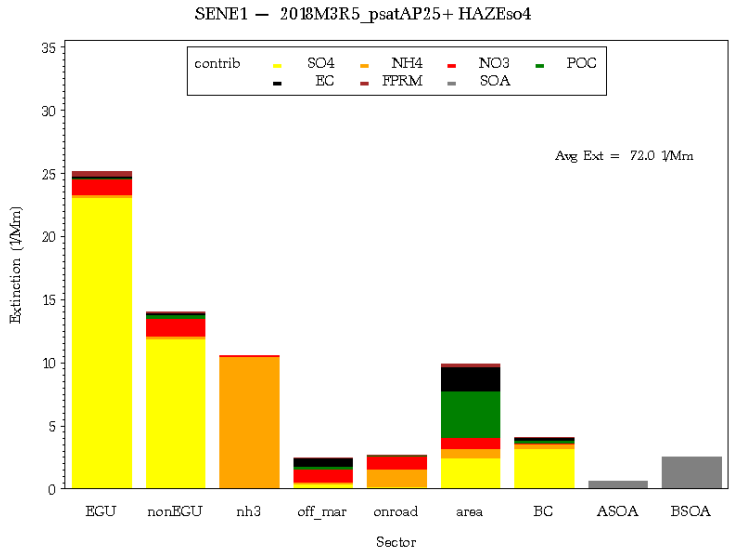
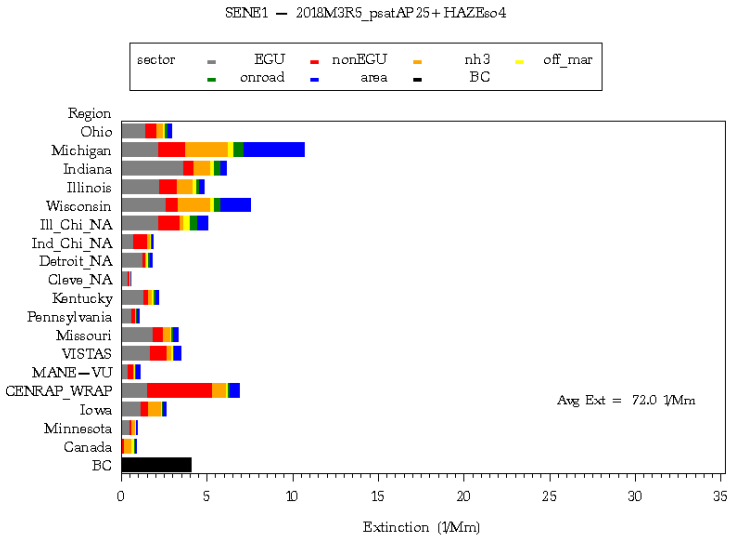
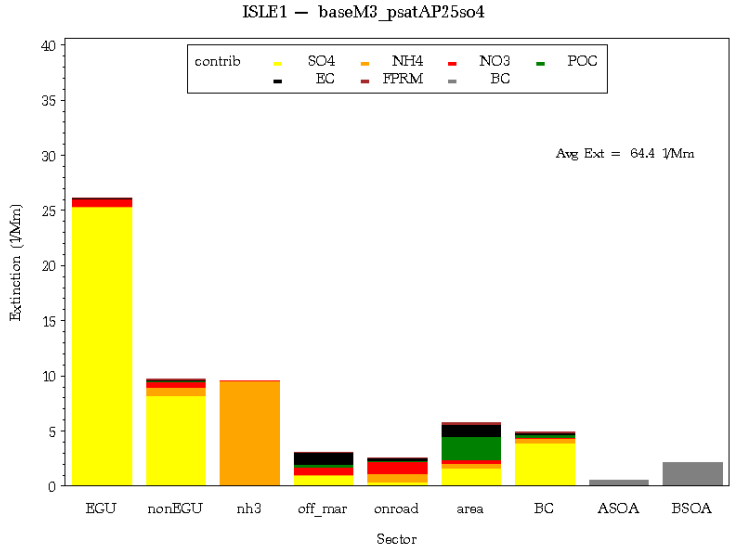
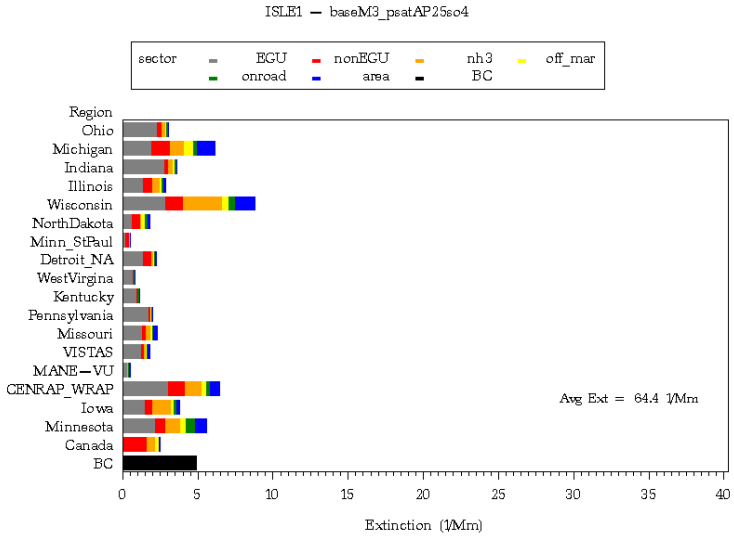




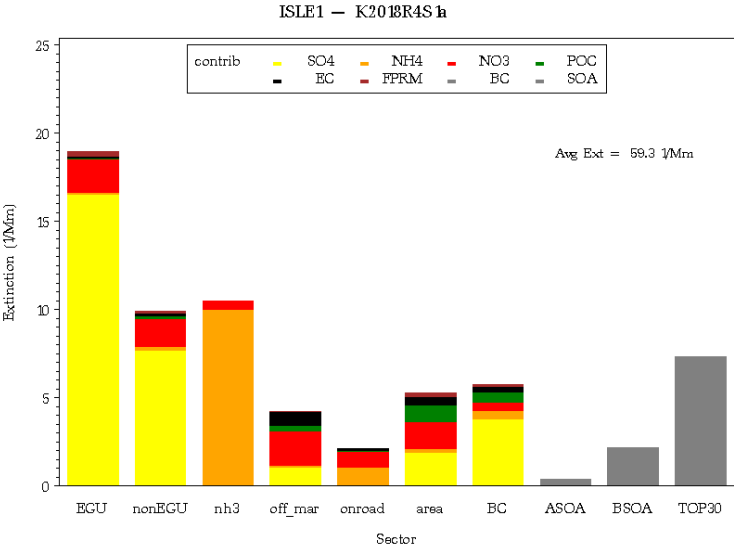
Isle Royale, Michigan

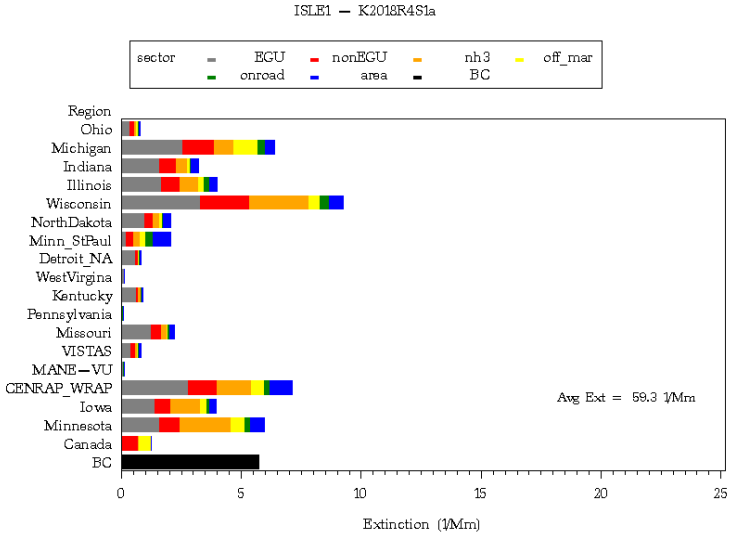
2005 (Round 5)



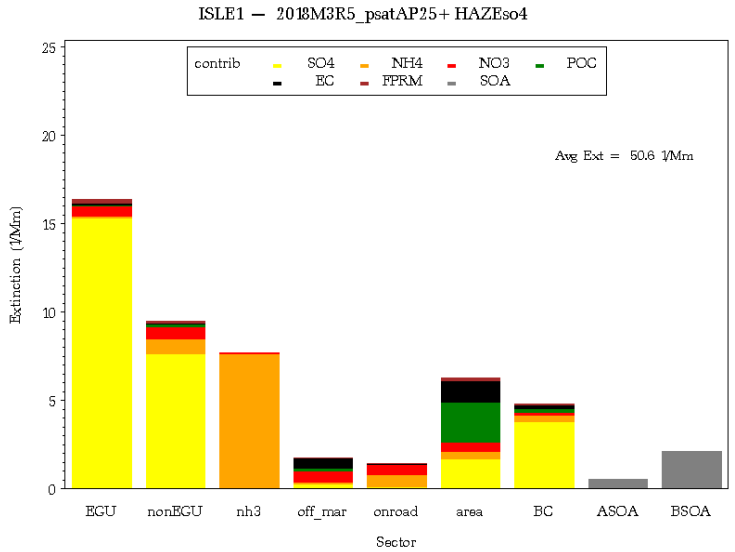


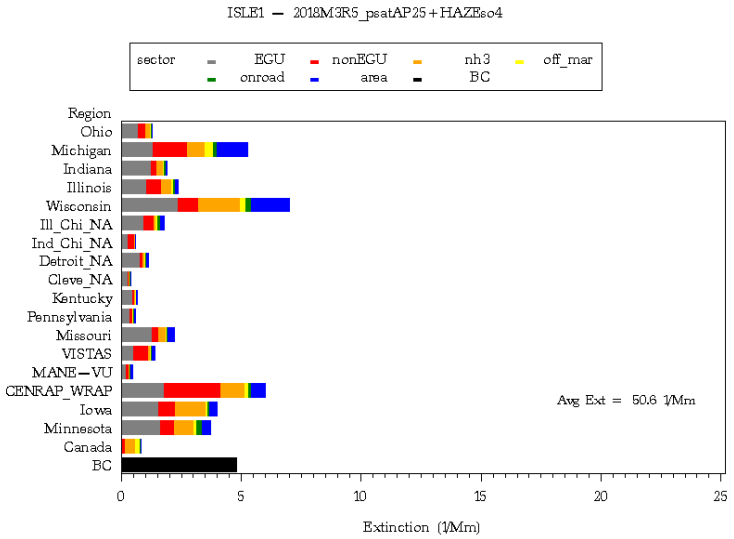
2018 (Round 4)





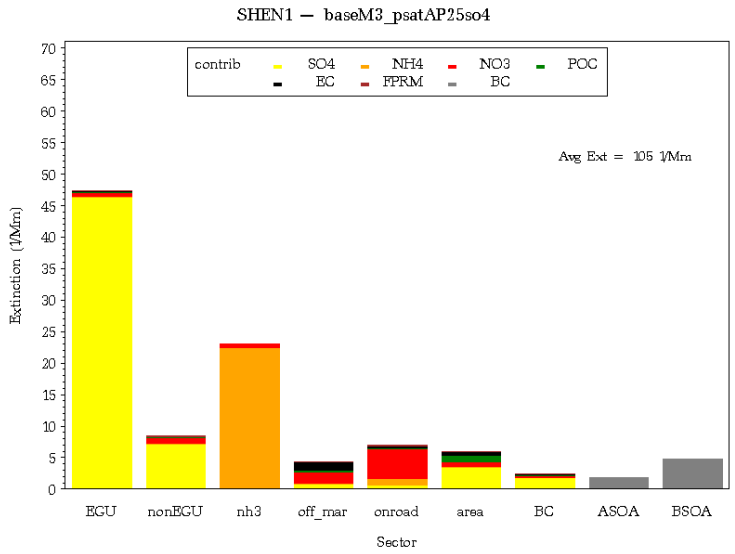
2018 (Round 5)

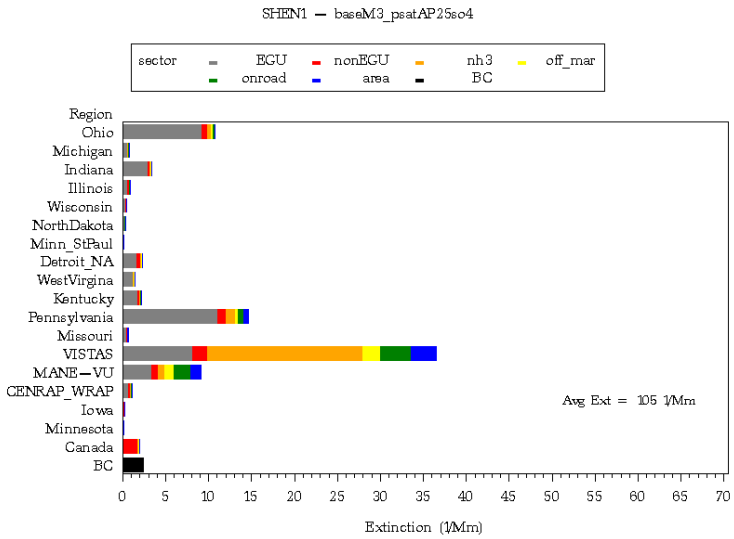




Shenandoah, Virginia

2005 (Round 5)





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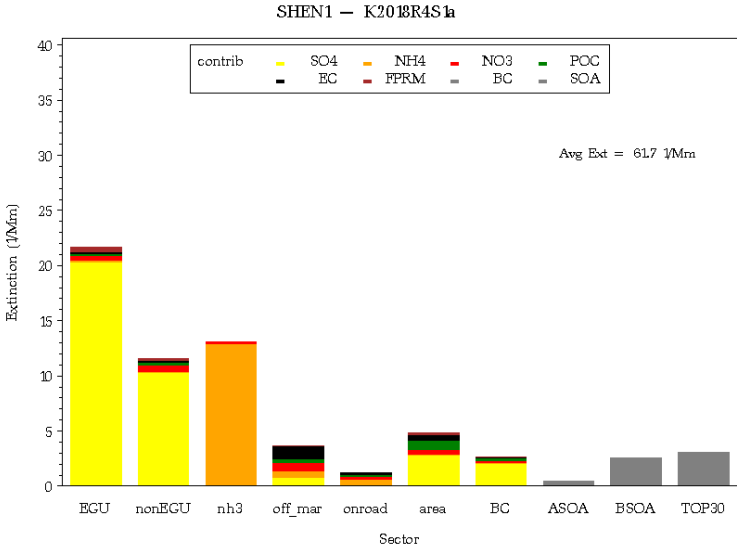

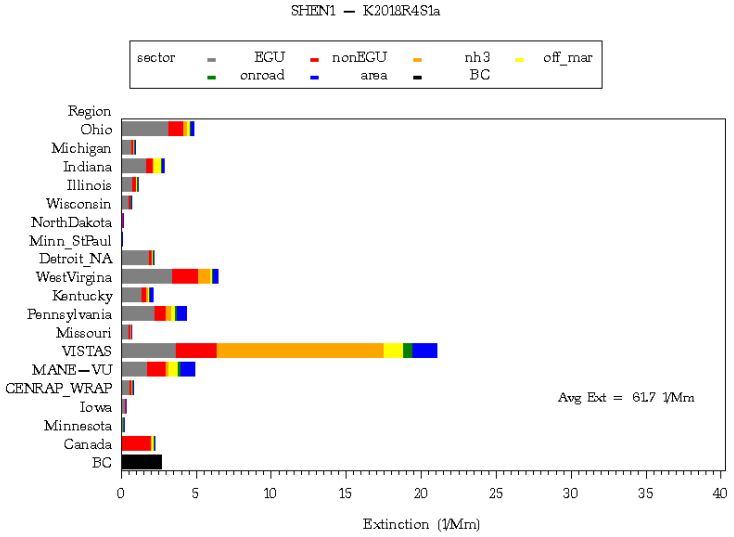

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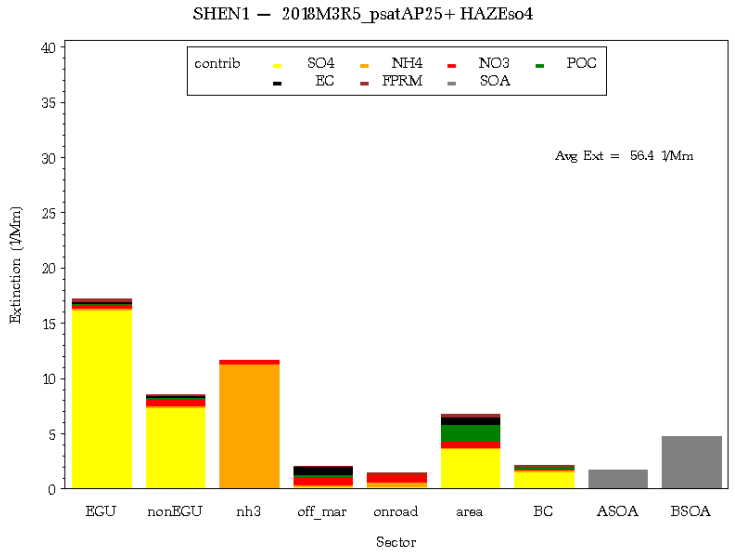
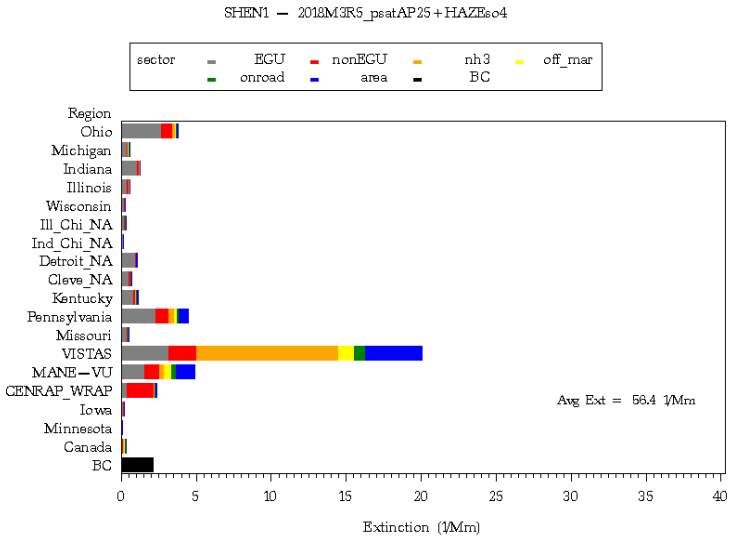
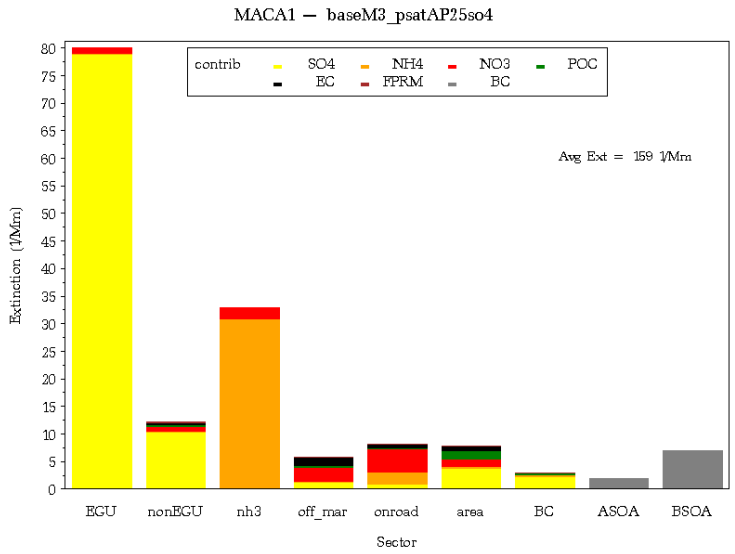
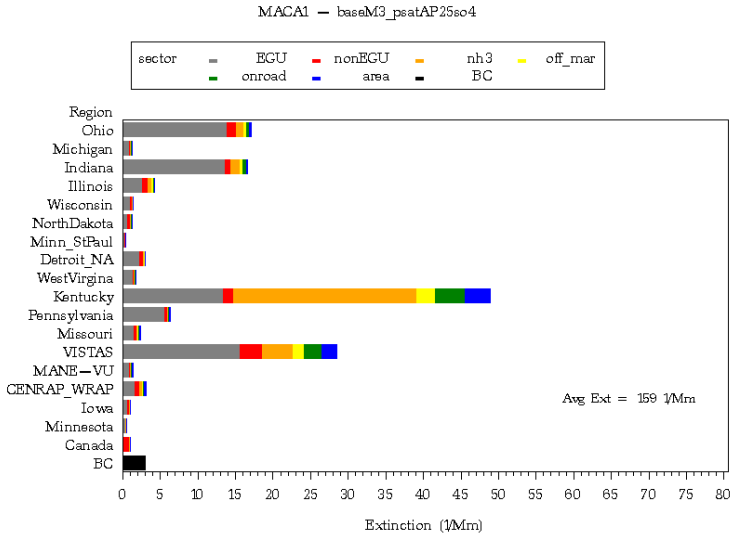




Mammoth Cave, Kentucky

2005 (Round 5)





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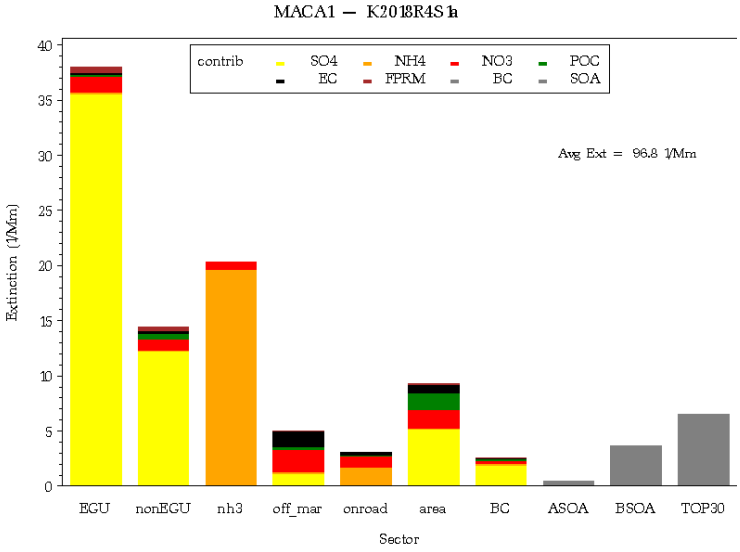

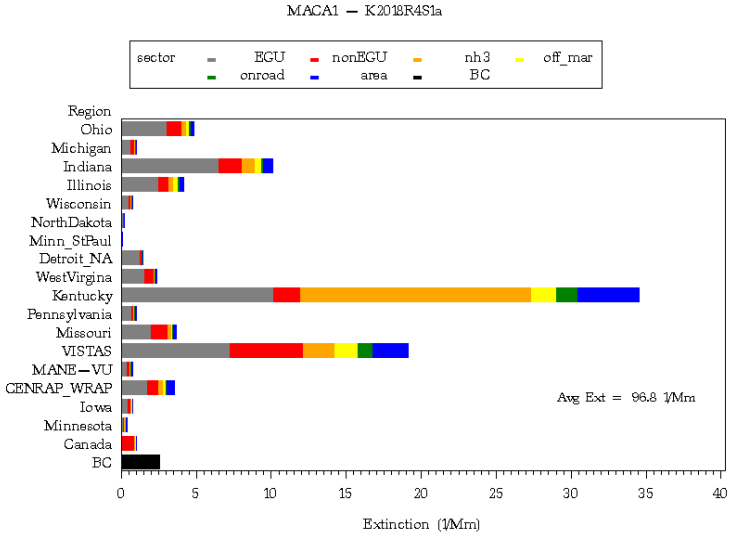

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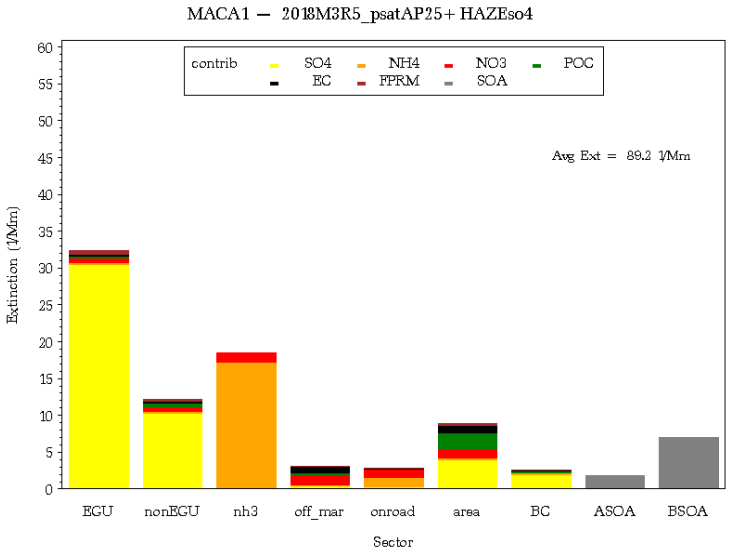
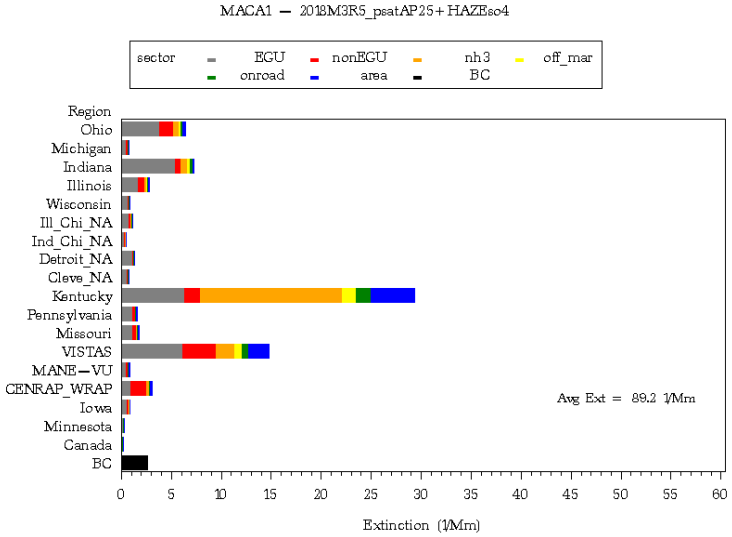
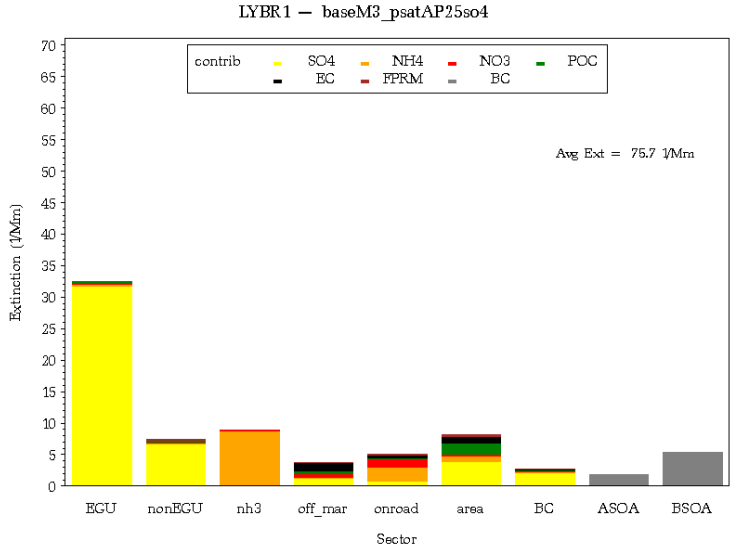
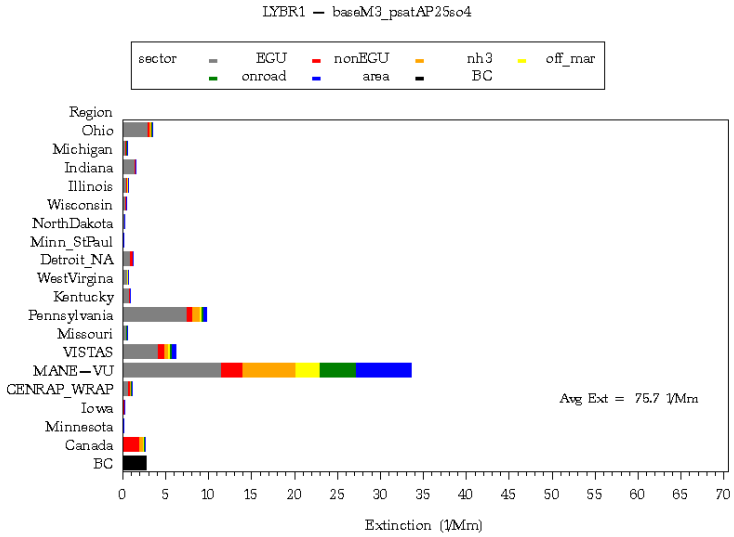




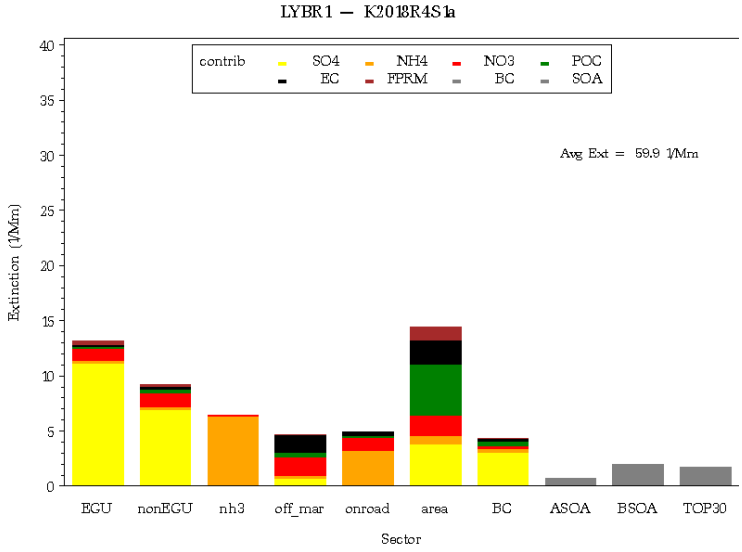
Lye Brook, Vermont

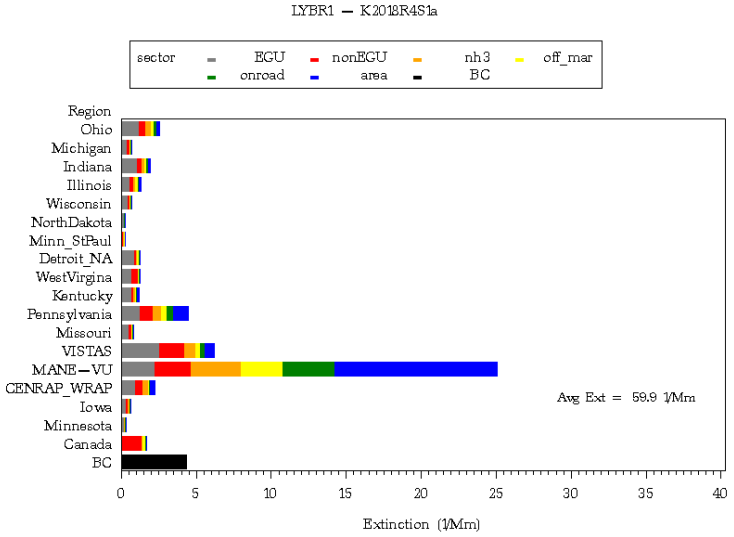
2005 (Round 5)





2018 (Round 4)





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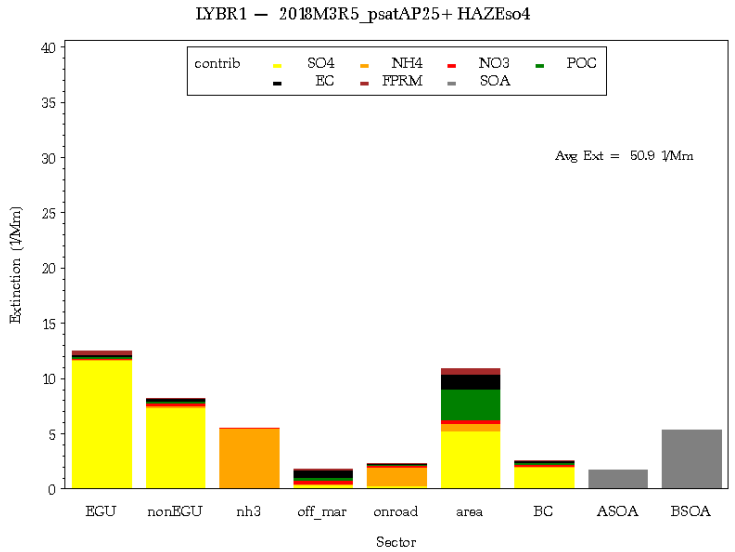
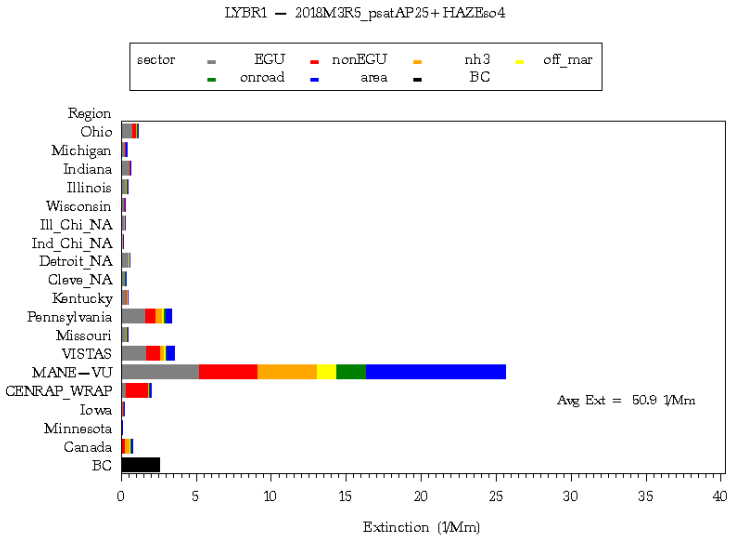




Weight of Evidence

E3: TSD Supplement w/o CAIR modeling

"Without CAIR"

Link to:

http://www.epa.ohio.gov/portals/27/SIP/Attain/E3_TSD_Supplement_without_CAIR_modeling_FINAL.pdf

Regional Air Quality Analyses for Ozone, PM2.5, and Regional Haze: Final Technical Support Document (Supplement), September 12, 2008

The purpose of this paper is to summarize a new modeling analysis performed by the Lake Michigan Air Directors Consortium (LADCO) to address the effect of the recent court decision vacating EPA's Clean Air Interstate Rule (CAIR). This new modeling is intended to supplement the LADCO Technical Support Document ("Regional Air Quality Analyses for Ozone, PM2.5, and Regional Haze: Final Technical Support Document", April 25, 2008), which summarizes the air quality analyses conducted by LADCO and its contractors to support the development of State Implementation Plans for ozone, PM2.5, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin.

Compared to the previous LADCO modeling (Round 5.1), the new modeling shows similar results for ozone, but much more nonattainment for PM2.5 and higher visibility levels for regional haze. Specifically, the new modeling shows:

> **Ozone:** Attainment of the 0.08 ppm standard by 2009 everywhere in the region, except Holland, MI, and nonattainment of the 0.075 ppm standard through at least 2018.
>
> **PM2.5**: Widespread nonattainment of annual (15 ug/m^3) and daily (35 ug/m^3) standards.
>
> **Haze:** Higher visibility levels on the 20% worst visibility days in 2018 in Class I areas in the eastern U.S., resulting in most areas being above the glide path.

Background: On July 11, 2008, the U.S. Court of Appeals for D.C. Circuit vacated EPA's CAIR rule (cite). The reductions in NOx and SO2 emissions associated with this rule were a key part of the LADCO States' attainment demonstrations for ozone and PM2.5 and the reasonable progress determinations for regional haze. LADCO's previous modeling (Round 5.1) relied on EGU emission projections from EPA's IPM3.0 analysis, which assumed implementation of Phases I and II of CAIR. For this new modeling, alternative EGU emission projections were developed, which did not rely on CAIR (or IPM).

Model Set-Up: The new modeling was performed consistent with LADCO's previous modeling (Round 5.1):

Model Version: CAMx v4.50beta_deposition
Future Years: 2009, 2012, 2018
Runs: (a) Ozone: Summer 2005 meteorology with 12 km grids
(b) PM2.5 and haze: Full year 2005 meteorology with 36 km grids

Emission Scenarios: The new modeling assumed the same set of "on the books" controls as in LADCO's previous modeling (Round 5.1) for all sectors, except EGUs. In light of the CAIR decision, three new EGU scenarios were prepared:

Scenario A: 2007 CEM-based emissions were projected for all states in the modeling domain based on EIA growth rates by state (NERC region) and fuel type. The assumed growth rates for the Midwest States were: MAIN (IL, IA, MO, WI): 8.8% (2007-2018); ECAR (IN, KY, MI, OH): 13.5% (2007-2018); and MAPP (MN): 15.1% (2007-2018). No control was applied. The annual emissions were temporalized based on profiles derived from 2004-2006 CEM data. (Note, these are the same temporal profiles used in Round 5.1.)

Scenario B. Scenario A emissions for the LADCO States and select neighboring states (e.g., MN, IA, MO, KY, TN, and WV) were adjusted by applying legally enforceable controls (i.e., emission reductions required by a Consent Decree, state rule, or permit). Only those legally enforceable controls identified (and justified) by the States were applied. The States also supplied the appropriate control factors. A table summarizing the Scenario B controls is provided in Appendix I.

Scenario C. For the years 2009 and 2012, Scenario A emissions for all states were adjusted by applying all planned SO2 and NOx controls based on the July 10 CAMD list (i.e., 90% reduction for scrubbers, 95% reduction for SCRs). Because the July 10 CAMD list only includes controls generally out to 2011, additional SO2 and NOx controls for the year 2018 were assumed for all BART-eligible EGUs in the five LADCO State plus MN, IA, MO, KY, TN, and MO list (i.e., 90% reduction for scrubbers, 95% reduction for SCRs).[1] All Scenario B controls were included in Scenario C. A table summarizing the Scenario C controls is provided in Appendix II.

Table 1 and Figure 1 provide a summary of the 5-state regional NOx and SO2 emissions for each scenario and future year. (Note, the CAIR emissions included here are based on EPA's IPM3.0 modeling.) Several comments on the emissions should be noted:

Summer NOx

- There is llittle difference between the three alternative scenarios and CAIR. This suggests that summer ozone concentrations for the alternative scenarios are likely to be similar to those predicted with CAIR (i.e., Round 5.1).

Annual NOx:

- There is a significant change in emissions between scenarios, mostly during the non-summer months.
- Scenario B reflects application of NOx controls in several states (e.g., IL,OH,WI).
- Because there are relatively few SCRs (in the LADCO States) on the CAMD list, Scenario C results in only a small emissions decrease compared to Scenario B.
- Assumed BART controls result in a significant emissions decrease.

Annual SO2

- There is a significant change in emissions between scenarios.
- Scenario B reflects application of SO2 controls in several states (e.g., IL,OH,WI).
- Because there are several FGDs (in the LADCO States) on the CAMD list, Scenario C results in a large emissions decrease compared to Scenario B.
- Assumed BART controls result in a significant emissions decrease (i.e., even lower emissions than the IPM-estimated CAIR emissions).

[1] A subsequent analysis was conducted with the following inventory changes: (a) 95% reduction for scrubbers, 90% redcuction for SCRs (consistent with EPA's default assumptions for IPM), and (b) revisions provided for a few plants in Indiana and Minnesota. The changes resulted in a relatively small difference in the regioinal NOx and SO2 emissions (e.g., about a 2% NOx increase and about a 1-2% decrease in SO2). To assess the impact of the changes, PM2.5 modleing was conducted with the new Scenario B and Scenario C emissions for 2012. The modeling showed little change in the predicted PM2.5 concentrations.

Figure 1. Regional NOx and SO2 Emissions

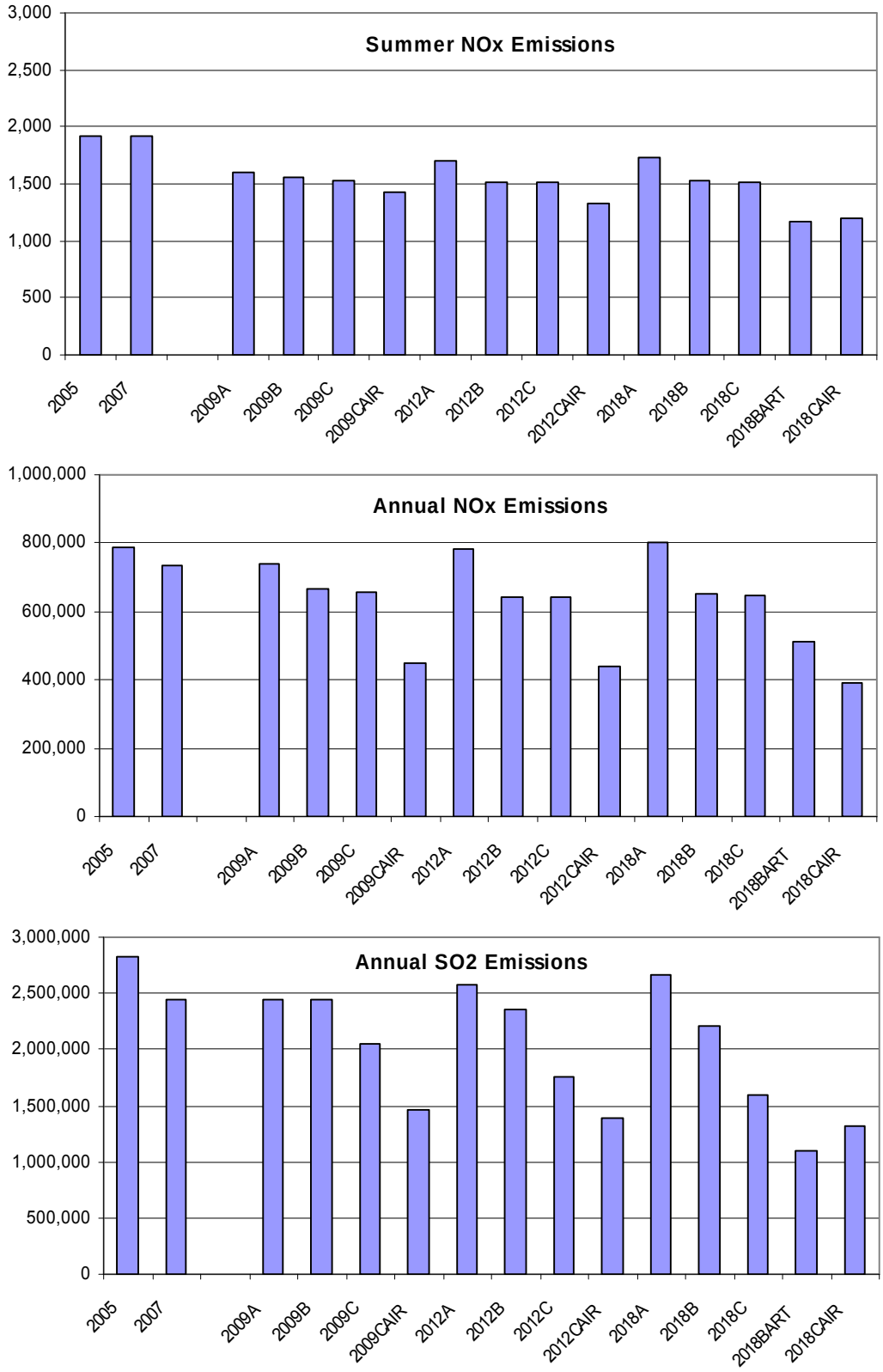


Table 1. Regional NOx and SO2 Emissions

Summer NOx Emissions (TPD)																
	2005	2007		2009 A	2009 B	2009 C	2010 CAIR	2012 A	2012 B	2012 C	2012 CAIR	2018 A	2018 B	2018 C	2018 C-BART	2018 CAIR
IL	305	305		311	311	311	275	340	236	236	266	333	227	227	219	224
IN	393	393		376	376	374	384	393	393	390	368	410	386	383	292	264
MI	393	393		350	350	350	242	366	366	366	229	377	377	377	260	243
OH	408	408		395	355	335	285	423	351	351	290	431	366	366	230	290
WI	413	413		167	160	160	238	184	170	170	177	183	168	168	168	177
	1,912	**1,912**		**1,599**	**1,552**	**1,530**	**1,424**	**1,706**	**1,516**	**1,513**	**1,330**	**1,734**	**1,524**	**1,521**	**1,169**	**1,198**

Annual NOx Emissions (TPY)																
	2005	2007		2009 A	2009 B	2009 C	2010 CAIR	2012 A	2012 B	2012 C	2012 CAIR	2018 A	2018 B	2018 C	2018 C-BART	2018 CAIR
IL	126,786	121,006		124,917	124,917	124,917	83,224	137,438	81,989	81,989	82,248	135,983	79,771	79,771	63,590	69,958
IN	214,727	203,493		203,776	203,776	201,947	133,188	212,790	212,790	210,877	125,541	221,950	212,805	210,810	177,027	90,415
MI	120,332	112,484		112,478	112,478	112,478	83,117	117,621	117,621	117,621	77,897	122,447	122,447	122,447	89,444	79,543
OH	255,554	240,351		240,016	173,071	164,911	94,346	251,065	172,514	172,514	97,679	261,644	179,737	179,737	125,762	95,678
WI	71,414	54,582		56,540	54,065	54,065	53,032	62,266	57,759	57,759	56,480	61,812	56,952	56,952	56,952	56,158
	788,812	**731,917**		**737,727**	**668,307**	**658,317**	**446,908**	**781,179**	**642,673**	**640,760**	**439,845**	**803,837**	**651,712**	**649,717**	**512,774**	**391,752**

Annual SO2 Emissions (TPY)																
	2005	2007		2009 A	2009 B	2009 C	2010 CAIR	2012 A	2012 B	2012 C	2012 CAIR	2018 A	2018 B	2018 C	2018 C-BART	2018 CAIR
IL	326,598	273,467		281,028	281,028	281,028	295,516	309,209	196,238	194,746	267,110	305,364	106,638	105,152	82,351	275,716
IN	866,964	722,301		721,252	721,252	619,486	374,335	754,323	754,323	558,567	379,144	786,551	764,065	559,945	426,695	359,915
MI	350,694	343,487		343,140	343,140	315,326	227,296	358,879	358,879	301,062	233,204	373,964	373,964	313,677	178,680	242,853
OH	1,100,510	960,820		959,466	959,466	693,438	427,145	1,003,633	897,099	572,807	370,532	1,045,945	819,770	481,623	333,740	315,560
WI	181,426	137,562		142,007	142,007	133,738	139,181	156,659	144,818	133,592	139,203	155,818	144,027	132,849	77,214	127,073
	2,826,192	**2,437,638**		**2,446,892**	**2,446,892**	**2,043,017**	**1,463,473**	**2,582,703**	**2,351,356**	**1,760,775**	**1,389,192**	**2,667,641**	**2,208,463**	**1,593,245**	**1,098,679**	**1,321,116**

Modeling Results: Several tables summarizing the modeling results are provided:

Table 2 - future year ozone and PM2.5 concentrations for key monitors in the LADCO region

Table 3 - number of monitoring sites greater than the National Ambient Air Quality Standards (NNAQS)

Table 4 – visibility levels for Class I areas in the eastern U.S.

Note, given that Scenario B and BART controls were only applied in an 11-state Midwest region, the validity of the results for other Class I areas in the eastern U.S. may be questionable. The Scenario C controls, on the other hand, cover all states and are, thus, likely valid in other Class I areas.

Spatial plots of the future year ozone and PM2.5 concentrations are provided in Figures 2 – 4.

Based on these results, the following key findings should be noted:

Ozone

- There is little change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows attainment of the 0.08 ppm (85 ppb) standard by 2009, except Holland. (Note, Holland does meet this standard by 2012.)
- The modeling shows nonattainment of the 0.075 ppm (75 ppb) standard through 2018.

PM2.5 - Annual

- There is a significant change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows extensive nonattainment of the annual standard.

PM2.5 - Daily

- There is a significant change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows extensive nonattainment of the daily standard.

Haze

- There is a significant change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows higher visibility levels in 2018 for the 20% worst visibility days (average about 0.5 deciviews for the northern Class I areas). The resulting visibility levels in the northern Class I areas (except Voyageurs) are above the glide path.

Table 2a. Ozone Modeling Results

		2005	2009				2012				2018				
			Round 5 without CAIR			Round 5 with CAIR	Round 5 without CAIR			Round 5 with CAIR	Round 5 without CAIR				Round 5 with CAIR
Site	Site ID	Base Year	Scen. A	Scen. B	Scen.C		Scen. A	Scen. B	Scen.C		Scen. A	Scen. B	Scen.C	Scen.C-BART	
Lake Michigan Area															
Chiwaukee	550590019	84.7	82.2	82.2	82.0	82.3	81.1	80.8	80.6	80.9	77.2	77.2	77.0	76.0	76.2
Racine	551010017	80.3	77.8	77.8	77.5	77.5	76.6	76.2	76.1	76.1	72.9	72.3	72.1	71.1	71.2
Milwaukee-Bayside	550890085	82.7	79.9	79.9	79.7	79.8	78.5	78.0	78.0	78.0	74.3	73.6	73.4	72.4	72.7
Harrington Beach	550890009	83.3	80.1	80.1	79.9	80.1	78.6	78.1	78.0	78.3	73.9	73.2	73.1	72.2	72.5
Manitowoc	550710007	**85.0**	80.8	80.8	80.7	80.8	79.0	78.5	78.4	78.6	73.9	73.2	73.1	72.0	72.5
Sheboygan	551170006	**88.0**	84.1	84.0	83.9	84.0	82.2	81.7	81.5	81.8	76.9	76.0	75.9	74.8	75.4
Kewaunee	550610002	82.7	78.2	78.2	78.0	78.1	76.4	75.9	75.7	75.9	71.3	70.7	70.5	69.4	69.9
Door County	550290004	**88.7**	84.1	84.1	83.9	83.9	82.0	81.4	81.3	81.5	76.5	75.6	75.5	74.2	74.7
Hammond	180892008	77.7	76.2	76.2	76.0	75.4	75.6	75.3	75.2	74.6	73.2	72.7	72.6	71.7	71.6
Whiting	180890030	79.3	77.8	77.8	77.7	77.0	77.2	76.9	76.8	76.2	74.8	74.3	74.2	73.2	73.1
Michigan City	180910005	77.0	74.5	74.5	74.3	73.9	73.3	72.9	72.8	72.5	69.7	69.2	69.1	68.1	68.1
Ogden Dunes	181270020	78.3	76.3	76.3	76.2	75.6	75.5	75.1	75.0	74.5	72.9	72.3	72.1	71.2	70.8
Holland	260050003	**90.0**	**85.7**	**85.7**	**85.5**	**85.3**	83.5	83.1	82.9	82.8	78.2	77.5	77.3	76.0	76.1
Jenison	261390005	82.0	76.8	76.8	76.7	76.0	75.1	74.6	74.5	74.5	70.2	69.6	69.5	67.9	68.7
Muskegon	261210039	**85.0**	80.6	80.6	80.5	80.5	78.6	78.2	78.1	78.0	73.5	72.8	72.8	71.5	71.9
Indianapolis Area															
Noblesville	189571001	82.7	78.3	78.3	78.1	78.1	76.1	75.9	75.7	75.6	70.2	69.9	69.8	68.9	68.7
Fortville	180590003	78.0	74.1	74.1	73.9	73.9	71.9	71.8	71.7	71.4	66.7	66.5	66.3	65.4	65.1
Fort B. Harrison	180970050	78.7	75.4	75.3	75.2	75.1	73.8	73.6	73.6	73.2	70.6	70.3	70.2	69.3	69.1
Detroit Area															
New Haven	260990009	86.0	82.4	82.3	82.1	81.4	81.4	81.2	81.1	80.2	78.1	77.8	77.7	76.5	76.1
Warren	260991003	84.0	82.4	82.3	82.2	81.3	82.1	81.8	81.7	80.7	79.7	79.4	79.3	78.0	77.6
Port Huron	261470005	82.7	78.2	78.2	78.1	77.5	76.5	76.3	76.2	75.5	72.6	72.5	72.3	70.9	70.9
Cleveland Area															
Ashtabula	390071001	**89.0**	84.2	84.1	83.9	83.4	82.0	81.8	81.6	81.0	76.8	76.5	76.4	74.8	75.1
Geauga	390550004	79.3	75.8	75.8	75.6	74.7	74.0	73.8	73.7	72.7	69.5	69.2	69.1	67.6	67.3
Eastlake	390850003	**86.3**	83.1	83.1	82.9	81.9	81.8	81.6	81.5	80.5	78.2	78.0	77.8	76.5	76.2
Akron	391530020	83.7	79.1	79.1	79.0	78.1	76.9	76.7	76.6	75.6	70.9	70.6	70.4	68.7	68.7
Cincinnati Area															
Wilmington	390271002	82.3	77.3	77.4	77.1	77.5	75.3	75.2	74.8	74.9	70.1	69.9	69.5	67.1	68.3
Sycamore	390610006	84.7	81.5	81.4	81.1	81.9	80.4	80.2	79.8	80.3	76.4	76.0	75.7	73.5	74.6
Lebanon	391650007	**87.7**	82.8	82.8	82.4	83.0	80.8	80.7	80.3	80.7	75.4	75.1	74.8	72.6	74.2
Columbus Area															
London	390970007	79.7	75.0	75.0	74.8	75.0	73.0	72.8	72.7	72.6	68.1	67.8	67.6	65.9	66.3
New Albany	390490029	**86.3**	82.1	82.1	81.9	81.8	80.2	80.0	79.9	79.6	74.7	74.3	74.2	73.3	73.0
Franklin	290490028	80.3	76.7	76.6	76.5	75.9	75.1	74.9	74.8	74.1	70.5	70.2	70.1	70.2	69.0
St. Louis Area															
W. Alton (MO)	291831002	**86.3**	81.1	81.2	81.1	81.0	80.0	79.9	79.9	78.6	76.9	76.8	76.7	74.2	74.9
Orchard (MO)	291831004	**87.0**	82.1	82.1	82.0	82.0	80.9	80.8	80.7	80.0	77.7	77.6	77.4	75.2	76.2
Sunset Hills (MO)	291890004	82.3	79.2	79.2	79.1	78.7	78.3	78.1	78.1	77.1	75.3	75.2	75.1	73.0	73.9
Arnold (MO)	290990012	82.3	77.8	77.8	77.7	77.2	76.7	76.6	76.5	75.6	73.6	73.4	73.4	71.3	72.0
Margaretta (MO)	295100086	83.0	79.8	79.8	79.7	79.3	78.8	78.7	78.6	77.9	75.7	75.6	75.5	73.7	74.4
Maryland Heights (MO)	291890014	**87.3**	**85.4**	**85.4**	**85.3**	84.0	84.3	84.1	84.0	81.7	81.1	80.9	80.8	78.4	78.1

Table 2b. $PM_{2.5}$ Modeling Results (Annual)

		2005		2009					2012					2018				
				Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR				Round 5 with CAIR
Site	Site ID	Base Year		Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C	Scen.C-BART	
Illinois																		
Chicago - Washington HS	170310022	15.2		14.9	14.8	14.5	14.1		14.8	14.7	14.2	14.0		15.0	14.6	14.2	13.7	13.9
Chicago - Mayfair	170310052	15.8		15.1	15.1	14.8	14.4		15.1	14.9	14.5	14.2		15.1	14.7	14.3	13.7	13.9
Chicago - Springfield	170310057	15.0		14.6	14.6	14.3	13.9		14.6	14.4	14.0	13.8		14.8	14.4	14.0	13.4	13.7
Chicago - Lawndale	170310076	14.9		14.5	14.5	14.2	13.8		14.5	14.3	13.9	13.7		14.7	14.3	13.9	13.3	13.6
Blue Island	170312001	14.8		14.4	14.4	14.0	13.7		14.4	14.2	13.8	13.6		14.5	14.1	13.7	13.2	13.4
Summit	170313301	15.2		14.9	14.9	14.6	14.2		14.9	14.7	14.3	14.0		15.0	14.6	14.3	13.7	13.9
Cicero	170316005	15.5		15.1	15.1	14.8	14.4		15.1	14.9	14.5	14.3		15.2	14.9	14.4	13.9	14.2
Granite City	171191007	16.7		16.3	16.2	15.9	15.1		16.1	16.0	15.3	14.9		15.9	15.6	14.9	14.2	14.3
E. St. Louis	171630010	15.6		15.2	15.2	14.8	14.1		15.0	14.9	14.3	13.9		14.9	14.6	14.0	13.3	13.4
Indiana																		
Jeffersonville	180190005	16.4		15.8	15.7	14.8	13.8		15.8	15.6	14.5	13.7		16.0	15.5	14.3	13.7	13.4
Jasper	180372001	15.2		14.3	14.2	13.4	12.4		14.2	14.0	13.0	12.2		14.3	13.9	12.8	12.1	11.8
Gary	180890031	15.6		13.9	13.9	13.5	13.0		13.8	13.6	13.1	12.8		13.7	13.4	12.9	12.3	12.4
Indy-Washington Park	180970078	15.3		14.4	14.4	13.6	12.8		14.3	14.2	13.2	12.6		14.3	13.9	12.9	12.2	12.0
Indy-W 18th Street	180970081	16.0		15.1	15.1	14.3			15.0	14.9	13.9			15.0	14.6	13.5	12.8	
Indy- Michigan Street	180970083	15.9		15.0	15.0	14.2	13.4		14.9	14.8	13.8	13.1		14.9	14.5	13.5	12.8	12.6
Michigan																		
Allen Park	261630001	14.5		11.0	14.0	13.5	13.0		14.0	13.8	13.2	12.8		13.9	13.6	13.0	12.4	12.4
Southwest HS	261630015	15.9		15.3	15.3	14.8	14.2		15.2	15.0	14.4	13.9		15.1	14.8	14.1	13.5	13.5
Linwood	261630016	14.6		14.1	14.1	13.6	13.1		14.0	13.9	13.3	12.8		13.9	13.6	13.0	12.5	12.5
Dearborn	261630033	17.5		17.0	17.0	16.4	15.8		16.9	16.7	16.0	15.5		16.8	16.4	15.7	15.1	15.1
Wyandotte	261630036	14.7		14.2	14.1	13.6	13.1		14.1	13.9	13.3	12.8		14.0	13.7	13.0	12.4	12.5
Ohio																		
Middletown - Bonita	390170003	16.2		15.3	15.2	14.3	13.5		15.2	15.0	13.9	13.2		15.2	14.8	13.7	13.0	12.8
Fairfield	390170016	15.8		15.1	15.0	14.1	13.1		15.1	14.9	13.7	12.9		15.2	14.7	13.5	12.8	12.5
Cleveland-28th Street	390350027	15.4		14.9	14.9	14.3	13.5		14.7	14.5	13.9	13.2		14.6	14.2	13.5	12.8	12.7
Cleveland-St. Tikhon	390350038	17.4		16.7	16.7	16.0	15.2		16.5	16.3	15.6	14.8		16.3	16.0	15.2	14.4	14.3
Cleveland-Broadway	390350045	16.5		15.9	15.8	15.2	14.4		15.6	15.5	14.8	14.0		15.5	15.1	14.4	13.6	13.5
Cleveland-GT Craig	390350060	17.1		16.5	16.4	15.8	15.0		16.3	16.1	15.4	14.6		16.1	15.7	15.0	14.2	14.1
Newburg Hts - Harvard Ave	390350065	16.0		15.4	15.3	14.7	14.0		15.2	15.0	14.3	13.6		15.1	14.7	14.0	13.2	13.1
Columbus - Fairgrounds	390490024	15.3		14.6	14.5	13.7	12.9		14.4	14.1	13.2	12.6		14.2	13.8	12.8	12.2	12.0
Columbus - Ann Street	390490025	15.1		14.4	14.3	13.5	12.7		14.2	13.9	13.1	12.4		14.1	13.6	12.6	12.0	11.9
Cincinnati - Seymour	390610014	17.3		16.6	16.5	15.5	14.5		16.5	16.3	15.1	14.3		16.6	16.2	14.9	14.2	13.8
Cincinnati - Taft Ave	390610040	15.5		14.8	14.7	13.8	12.8		14.8	14.6	13.4	12.6		14.9	14.5	13.2	12.5	12.2
Cincinnati - 8th Ave	390610042	16.9		12.0	16.1	15.0	14.0		16.1	15.9	14.7	13.8		16.2	15.7	14.4	13.7	13.4
Sharonville	390610043	15.6		14.9	14.8	13.9	12.9		14.9	14.7	13.5	12.7		14.9	14.5	13.3	12.6	12.3
Norwood	390617001	16.2		15.5	15.4	14.4	13.4		15.4	15.2	14.0	13.2		15.5	15.1	13.8	13.1	12.8
St. Bernard	390618001	17.6		16.8	16.7	15.7	14.7		16.7	16.5	15.3	14.4		16.8	16.4	15.1	14.3	14.0
Steubenville	390810016	15.8		14.5	14.4	13.5	12.8		14.3	14.2	13.1	12.5		14.8	14.5	13.3	12.9	12.7
Mingo Junction	390811001	16.5		15.2	15.2	14.3	13.5		15.0	14.9	13.8	13.2		15.6	15.2	14.0	13.6	13.4
Ironton	390870010	15.2		14.8	14.6	13.6	12.8		14.6	14.4	13.2	12.5		14.8	14.1	12.8	12.4	12.3
Dayton	391130032	15.5		14.9	14.8	14.0	13.2		14.8	14.6	13.6	12.9		14.8	14.3	13.3	12.6	12.4
New Boston	391450013	14.7		12.0	14.0	13.0	12.1		14.1	13.8	12.5	11.9		14.2	13.6	12.2	11.7	11.6
Canton - Dueber	391510017	16.3		15.7	15.6	14.8	14.0		15.5	15.3	14.4	13.6		15.4	14.9	14.0	13.3	13.3
Canton - Market	391510020	14.6		11.0	14.1	13.3	12.6		13.9	13.7	12.9	12.3		13.9	13.5	12.6	12.0	11.9
Akron - Brittain	391530017	15.1		14.6	14.5	13.8	13.0		14.4	14.2	13.4	12.7		14.3	13.8	13.0	12.3	12.3
Akron - W. Exchange	391530023	14.3		13.7	13.7	13.0	12.3		13.6	13.3	12.6	12.0		13.4	13.0	12.2	11.6	11.5

Table 2c. $PM_{2.5}$ Modeling Results (Daily)

			2005		2009					2012					2018				
					Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR				Round 5 with CAIR
Key Site	County	Site ID	Base Year		Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C	Scen. C - BART	
Illinois																			
Chicago - Washington HS	Cook	170310022	36.6		36	36	36	36		36	36	37	36		37	36	37	37	35
Chicago - Mayfair	Cook	170310052	40.3		37	37	37	36		37	36	37	36		38	37	37	37	36
Chicago - Springfield	Cook	170310057	37.4		34	34	33	32		35	34	33	32		36	34	33	33	31
Chicago - Lawndale	Cook	170310076	38.1		35	35	35	35		36	35	36	35		36	35	36	36	34
McCook	Cook	170311016	43.0		39	39	39	39		40	39	40	39		40	40	41	40	38
Blue Island	Cook	170312001	37.7		35	35	35	34		36	35	36	34		36	35	36	36	33
Schiller Park	Cook	170313103	41.6		40	40	40	39		40	40	40	39		41	40	40	39	39
Summit	Cook	170313301	40.2		38	38	39	38		39	38	39	38		39	38	39	39	37
Maywood	Cook	170316005	39.2		38	38	38	38		38	38	39	38		39	38	39	39	37
Granite City	Madison	171191007	39.2		36	36	35	33		36	35	34	33		36	35	35	33	32
E. St. Louis	St. Clair	171630010	33.7		31	31	30	28		31	30	29	28		31	30	30	29	28
Indiana																			
Jeffersonville	Clark	180190005	38.4		35	33	31	29		35	34	32	31		37	35	34	33	31
Jasper	Dubois	180372001	36.2		32	32	30	28		32	32	30	29		33	31	31	30	28
Gary - IITRI	Lake	180890022	39.0		35	35	35	34		35	34	35	34		36	36	36	35	35
Gary - Burr School	Lake	180890026	39.0		34	34	34	33		34	34	35	34		34	34	34	34	32
Gary	Lake	180890031	35.2		29	28	26	24		28	28	24	24		29	28	27	27	27
Indy-West Street	Marion	180970043	38.0		34	34	33	33		35	35	34	33		36	35	34	34	33
Indy-English Avenue	Marion	180970066	38.0		34	34	32	32		35	34	33	32		35	34	33	33	32
Indy-Washington Park	Marion	180970078	36.6		33	33	32	31		33	33	32	31		34	33	32	32	32
Indy-W 18th Street	Marion	180970081	38.3		33	33	31	31		33	33	32	31		34	33	32	32	31
Indy- Michigan Street	Marion	180970083	36.0		32	32	29	28		32	31	29	28		32	31	29	29	29
Michigan																			
Luna Pier	Monroe	261150005	38.9		34	34	32	32		34	34	32	32		34	33	32	31	31
Oak Park	Oakland	261250001	39.9		38	38	37	36		38	37	37	36		38	37	37	36	35
Port Huron	St. Clair	261470005	39.6		36	35	35	34		35	35	35	34		35	35	34	33	33
Ypsilanti	Washtenaw	261610008	39.5		37	37	36	35		37	36	36	35		37	36	36	35	34
Allen Park	Wayne	261630001	38.6		36	36	36	35		36	35	35	34		36	35	35	34	33
Southwest HS	Wayne	261630015	40.1		36	36	36	35		36	35	35	35		36	35	35	34	33
Linwood	Wayne	261630016	43.0		40	40	40	39		40	40	40	39		40	39	39	39	38
E 7 Mile	Wayne	261630019	41.0		39	39	39	38		39	39	39	38		39	38	38	38	37
Dearborn	Wayne	261630033	43.9		41	41	41	40		41	41	41	40		41	40	40	40	39
Wyandotte	Wayne	261630036	37.2		36	36	36	35		35	35	35	35		35	35	35	35	34
Newberry	Wayne	261630038	42.7		39	39	39	38		39	38	38	37		39	38	38	37	36
FIA	Wayne	261630039	39.7		35	34	34	33		35	34	34	33		35	34	33	33	31
Ohio																			
Middleton	Butler	390170003	39.3		33	32	29	28		33	33	29	28		34	32	29	28	27
Fairfield	Butler	390170016	37.1		32	31	29	27		31	30	28	28		32	30	29	28	27
	Butler	390170017	40.8		33	32	30	29		33	33	30	29		33	32	30	29	28
Cleveland-28th Street	Cuyahoga	390350027	36.9		34	34	33	32		34	33	33	32		34	33	33	31	31
Cleveland-St. Tikhon	Cuyahoga	390350038	44.2		40	40	37	36		40	39	36	35		40	38	36	35	34
Cleveland-Broadway	Cuyahoga	390350045	38.8		35	35	33	31		35	34	32	30		35	34	31	29	29
Cleveland-GT Craig	Cuyahoga	390350060	42.1		39	39	38	37		39	38	38	37		39	38	37	36	35
Newburg Hts - Harvard Ave	Cuyahoga	390350065	38.9		35	35	33	31		35	34	32	30		36	35	32	31	30
Columbus - Fairgrounds	Franklin	390490024	38.5		34	34	33	33		34	33	32	32		34	34	33	32	31
Columbus - Ann Street	Franklin	390490025	38.5		34	33	31	31		33	33	31	31		34	33	31	31	30
Cincinnait	Hamilton	390610006	40.6		33	33	30	27		33	32	29	28		34	32	29	28	27

Table 2c. $PM_{2.5}$ Modeling Results (Daily)

			2005		2009					2012					2018				
					Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR				Round 5 with CAIR
Key Site	**County**	**Site ID**	**Base Year**		**Scen. A**	**Scen. B**	**Scen.C**			**Scen. A**	**Scen. B**	**Scen.C**			**Scen. A**	**Scen. B**	**Scen.C**	**Scen. C - BART**	
Cincinnati - Seymour	Hamilton	390610014	38.4		33	33	28	26		33	32	27	25		33	31	29	25	24
Cincinnati - Taft Ave	Hamilton	390610040	36.7		31	30	26	24		31	30	26	24		32	29	26	24	23
Cincinnati - 8th Ave	Hamilton	390610042	37.3		32	32	30	28		32	31	29	28		33	31	29	28	27
Sharonville	Hamilton	390610043	36.0		32	31	30	28		32	31	29	28		32	31	29	28	27
Norwood	Hamilton	390617001	38.8		34	33	32	30		33	33	31	30		34	33	31	30	29
St. Bernard	Hamilton	390618001	40.6		35	35	32	30		35	34	31	30		35	33	32	31	29
Steubenville	Jefferson	390810016	40.7		**36**	35	32	29		35	34	30	28		**37**	35	31	29	28
Mingo Junction	Jefferson	390811001	42.0		**37**	**37**	33	30		**37**	**36**	32	30		**38**	**36**	32	30	30
Dayton	Montgomery	391130032	37.8		34	33	31	30		33	33	31	30		34	33	31	31	30
Canton - Dueber	Stark	391510017	38.6		33	32	30	28		33	31	30	28		33	30	29	28	27
Akron - Brittain	Summit	391530017	38.1		33	33	31	30		33	32	31	30		33	32	30	29	29
Wisconsin																			
Green Bay - Est High	Brown	550090005	37.1		35	34	35	35		34	35	35	34		33	33	33	32	32
Madison	Dane	550250047	36.4		33	33	32	32		33	32	32	31		32	31	30	29	29
Milwaukee-Health Center	Milwaukee	550790010	38.7		35	35	35	35		35	35	35	34		35	34	34	34	33
Milwaukee-SER Hdqs	Milwaukee	550790026	37.4		34	34	34	34		34	34	34	34		34	34	34	34	33
Milwaukee-Virginia FS	Milwaukee	550790043	39.9		**37**	**37**	**37**	**36**		**37**	**36**	**37**	**36**		**36**	**36**	**37**	**36**	**36**
Milwaukee- Fire Dept Hdqs	Milwaukee	550790099	37.8		34	34	33	33		34	33	33	32		34	33	33	33	32
Waukesha	Waukesha	551330027	35.5		32	32	32	31		32	32	32	31		32	31	31	30	29

Table 3. Modeling Results: Number of Sites > NAAQS

Ozone (85 ppb)		Round 5 without CAIR				Round 5 w/ CAIR
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	0	0	0	0	----	0
IN	0	0	0	0	----	0
MI	3	1	1	1	----	1
OH	4	0	0	0	----	0
WI	2	0	0	0	----	0
Total	**9**	**1**	**1**	**1**		**1**
2012						
IL	0	0	0	0	----	0
IN	0	0	0	0	----	0
MI	3	0	0	0	----	0
OH	4	0	0	0	----	0
WI	2	0	0	0	----	0
Total	**9**	**0**	**0**	**0**		**0**
2018						
IL	0	0	0	0	0	0
IN	0	0	0	0	0	0
MI	3	0	0	0	0	0
OH	4	0	0	0	0	0
WI	2	0	0	0	0	0
Total	**9**	**0**	**0**	**0**	**0**	**0**
Ozone (75 ppb)		**Round 5 without CAIR**				**Round5 w/ CAIR**
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	12	6	6	6	----	4
IN	26	10	9	8	----	5
MI	21	12	12	12	----	12
OH	45	27	25	24	----	21
WI	12	10	10	10	----	10
Total	**116**	**65**	**62**	**60**	**----**	**52**
2012						
IL	12	3	3	3	----	1
IN	26	5	4	4	----	3
MI	21	9	8	8	----	6
OH	45	18	14	12	----	11
WI	12	10	9	9	----	9
Total	**116**	**45**	**38**	**36**		**30**
2018						
IL	12	0	0	0	0	0
IN	26	0	0	0	0	0
MI	21	3	3	3	3	3
OH	45	3	3	2	1	1
WI	12	3	2	1	1	1
Total	**116**	**9**	**8**	**6**	**5**	**5**

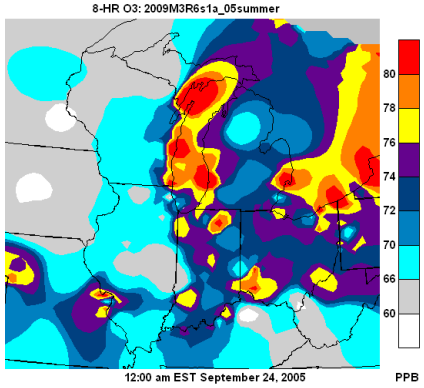
PM2.5 - Annual		Round 5 without CAIR				Round 5 w/ CAIR
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	7	4	4	1	----	1
IN	6	2	2	0	----	0
MI	2	2	2	1	----	1
OH	26	13	12	5	----	1
WI	0	0	0	0	----	0
Total	**41**	**21**	**20**	**7**		**3**
2012						
IL	7	3	1	1	----	0
IN	6	1	1	0	----	0
MI	2	2	1	1	----	1
OH	26	12	9	4	----	0
WI	0	0	0	0	----	0
Total	**41**	**18**	**12**	**6**		**1**
2018						
IL	7	3	1	0	0	0
IN	6	1	1	0	0	0
MI	2	2	1	1	1	1
OH	26	13	8	2	0	0
WI	0	0	0	0	0	0
Total	**41**	**19**	**11**	**3**	**1**	**1**
PM2.5 - Daily						
		Round 5 without CAIR				**Round 5 w/ CAIR**
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	16	7	7	6	----	6
IN	13	0	0	0	----	0
MI	14	10	9	9	----	5
OH	31	4	3	2	----	2
WI	8	1	1	1	----	1
Total	**82**	**22**	**20**	**18**	**----**	**14**
2012						
IL	16	9	6	8	----	6
IN	13	0	0	0	----	0
MI	14	8	6	6	----	5
OH	31	3	3	2	----	1
WI	8	1	1	1	----	1
Total	**82**	**21**	**16**	**17**		**13**
2018						
IL	16	10	6	8	8	5
IN	13	4	1	1	0	0
MI	14	8	6	6	5	4
OH	31	5	3	2	1	0
WI	8	1	1	1	1	1
Total	**82**	**28**	**17**	**18**	**15**	**10**

Table 4. Modeling Results: Future Year Visibility Levels

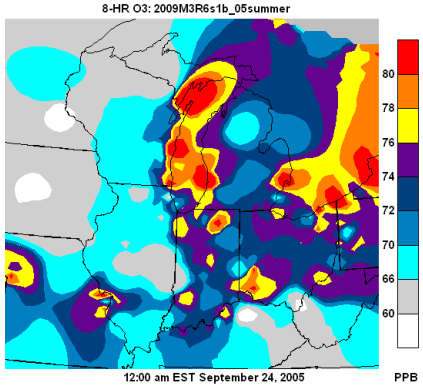
Worst 20%				2018				
				Round 5 without CAIR				Round 5 w/ CAIR
Site	Baseline (2000-2004)	2018 URP		Scen. A	Scen. B	Scen. C	Scen. C-BART	
BOWA1	19.86	17.94		19.09	18.87	18.54	18.02	17.94
VOYA2	19.48	17.75		18.60	18.44	18.17	17.77	17.63
SENE1	24.38	21.64		24.02	23.58	23.03	22.38	22.59
ISLE1	21.59	19.43		21.05	20.86	20.62	20.22	20.09
ISLE9	21.59	19.43		20.83	20.58	20.38	19.84	19.84
HEGL1	26.75	23.13		26.24	25.83	24.87	24.23	24.22
MING1	28.15	24.27		27.51	26.98	25.81	24.93	24.74
CACR1	26.36	22.91		25.32	24.80	23.57	22.97	22.44
UPBU1	26.27	22.82		25.31	24.79	23.50	22.79	22.59
MACA1	31.37	26.64		30.11	29.08	27.06	26.24	26.10
DOSO1	29.05	24.69		27.88	26.96	24.36	23.74	23.00
SHEN1	29.31	25.12		28.38	27.65	25.24	24.69	23.92
JARI1	29.12	24.91		28.06	27.21	25.00	24.48	24.06
BRIG1	29.01	25.05		28.10	28.07	26.57	26.25	25.21
LYBR1	24.45	21.48		24.06	23.86	22.58	22.30	21.14
ACAD1	22.89	20.45		22.88	22.76	22.31	22.16	21.49
Best 20%				**2018**				
				Round 5 without CAIR				**Round 5 w/ CAIR**
Site	**Baseline (2000-2004)**	**2018 Max**		**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
BOWA1	6.42	6.42		6.20	6.17	6.16	6.12	6.14
VOYA2	7.09	7.09		6.87	6.83	6.81	6.78	6.75
SENE1	7.14	7.14		7.80	7.78	7.81	7.77	7.71
ISLE1	6.75	6.75		6.77	6.76	6.72	6.67	6.60
ISLE9	6.75	6.75		6.63	6.61	6.58	6.53	6.52
HEGL1	12.84	12.84		12.17	12.20	12.07	11.63	11.66
MING1	14.46	14.46		13.78	13.77	13.70	13.37	13.28
CACR1	11.24	11.24		10.94	10.99	10.97	10.78	10.52
UPBU1	11.71	11.71		11.18	11.23	11.18	10.96	10.73
MACA1	16.51	16.51		16.32	16.21	15.76	15.34	15.25
DOSO1	12.28	12.28		12.02	11.84	11.27	11.03	11.00
SHEN1	10.93	10.93		10.98	10.91	10.25	10.16	9.91
JARI1	14.21	14.21		14.19	13.98	13.42	13.21	13.14
BRIG1	14.33	14.33		14.32	14.46	14.22	14.17	13.92
LYBR1	6.37	6.37		6.39	6.38	6.31	6.28	6.14
ACAD1	8.78	8.78		8.97	8.96	8.90	8.89	8.82

Figure 2. Ozone Modeling Results

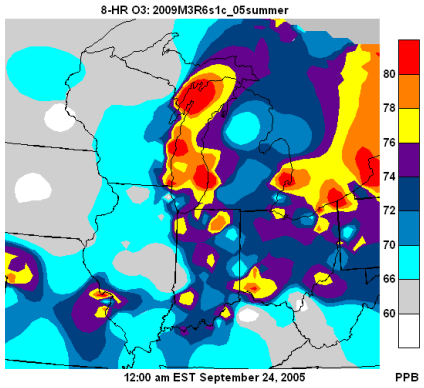
2009 Round 5 – Scen. A



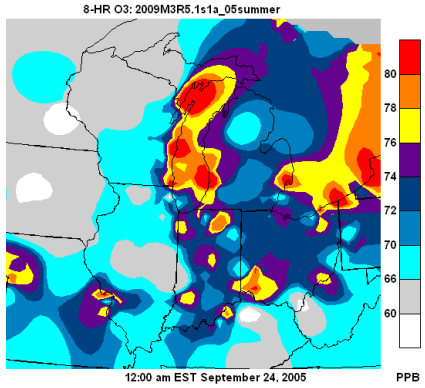
Round 5 – Scen. B



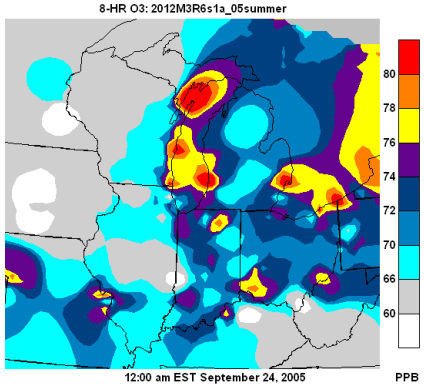
Round 5 – Scen. C



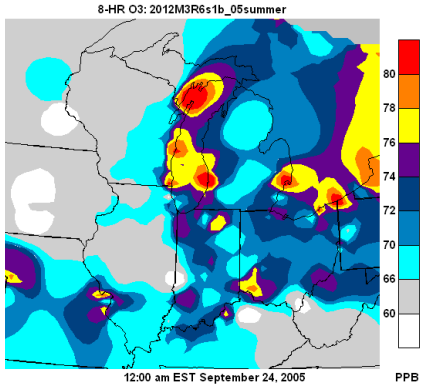
Round 5 - CAIR



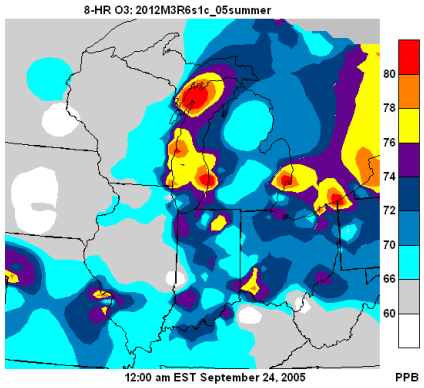
2012 Round 5 – Scen. A



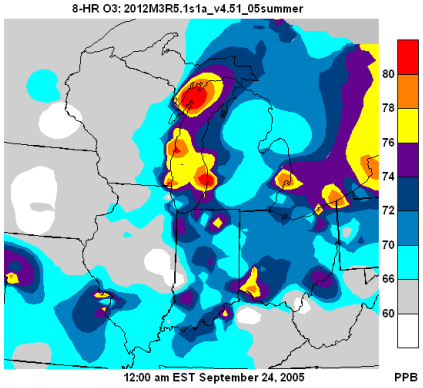
Round 5 – Scen. B



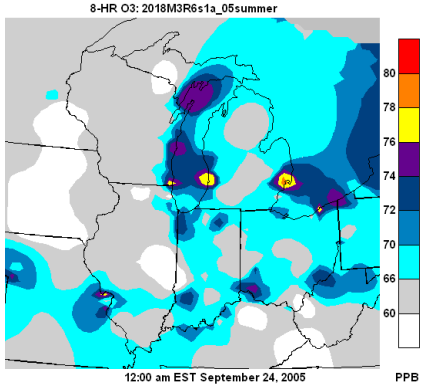
Round 5 – Scen. C



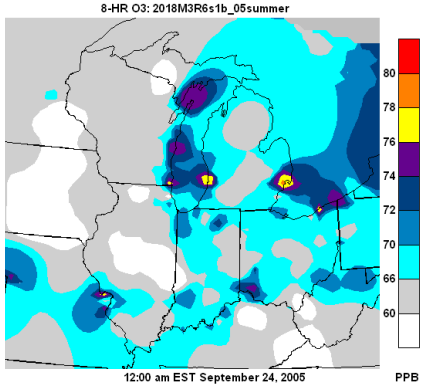
Round 5 - CAIR



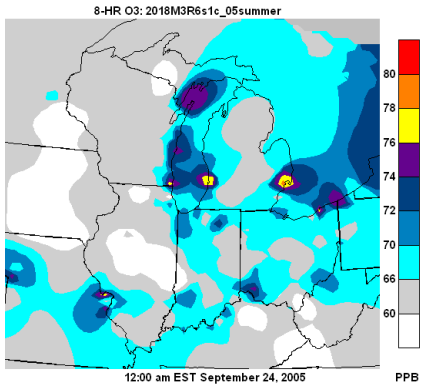
2018 Round 5 – Scen. A



Round 5 – Scen. B



Round 5 – Scen. C



Round 5 - CAIR

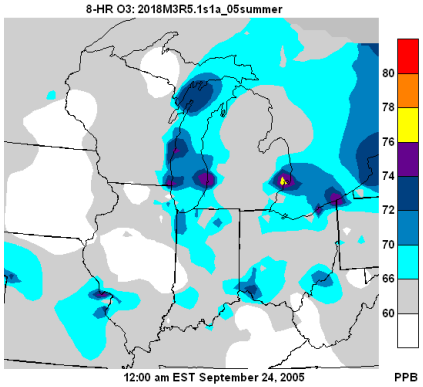


Figure 3. PM2.5 Annual Modeling Results

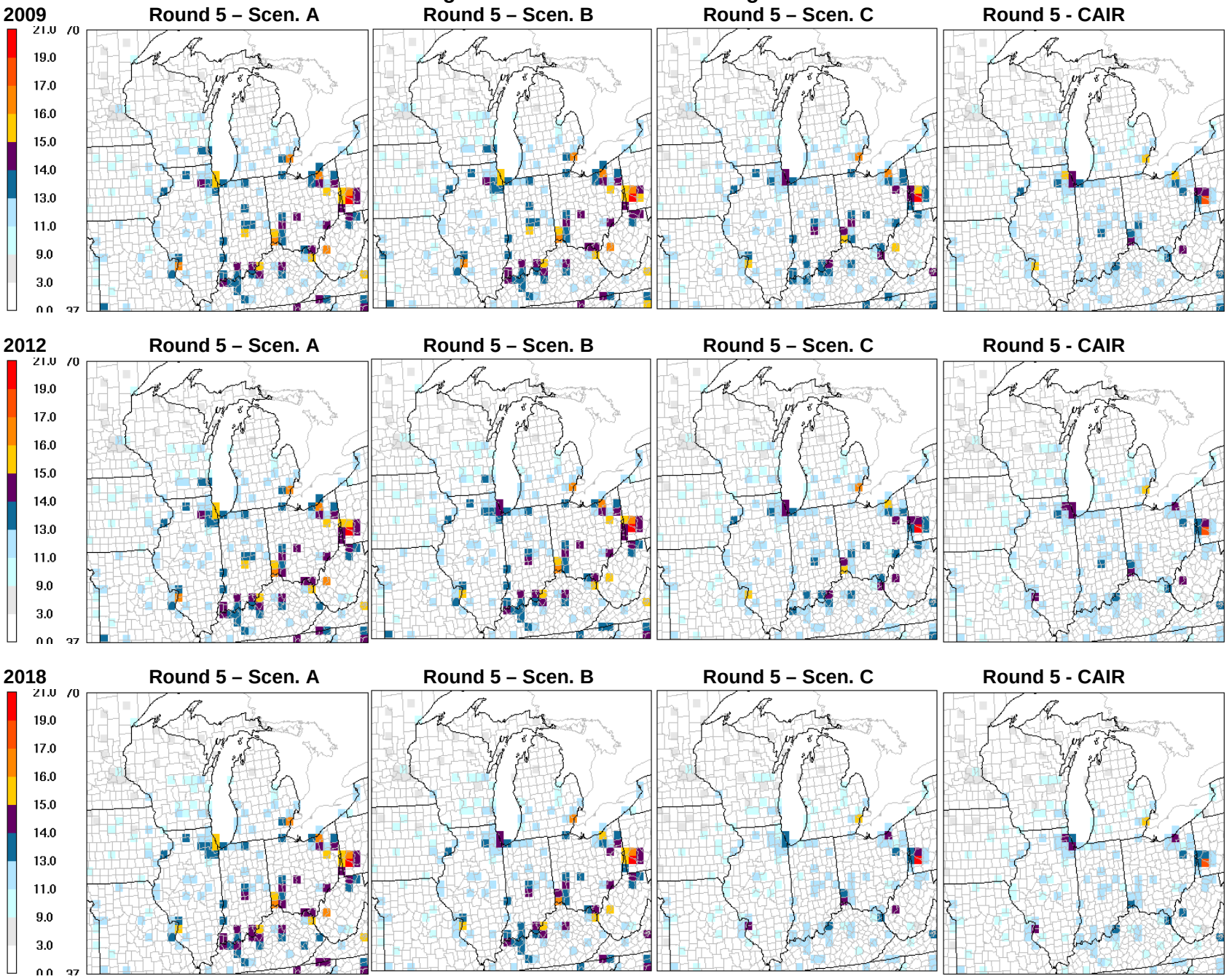
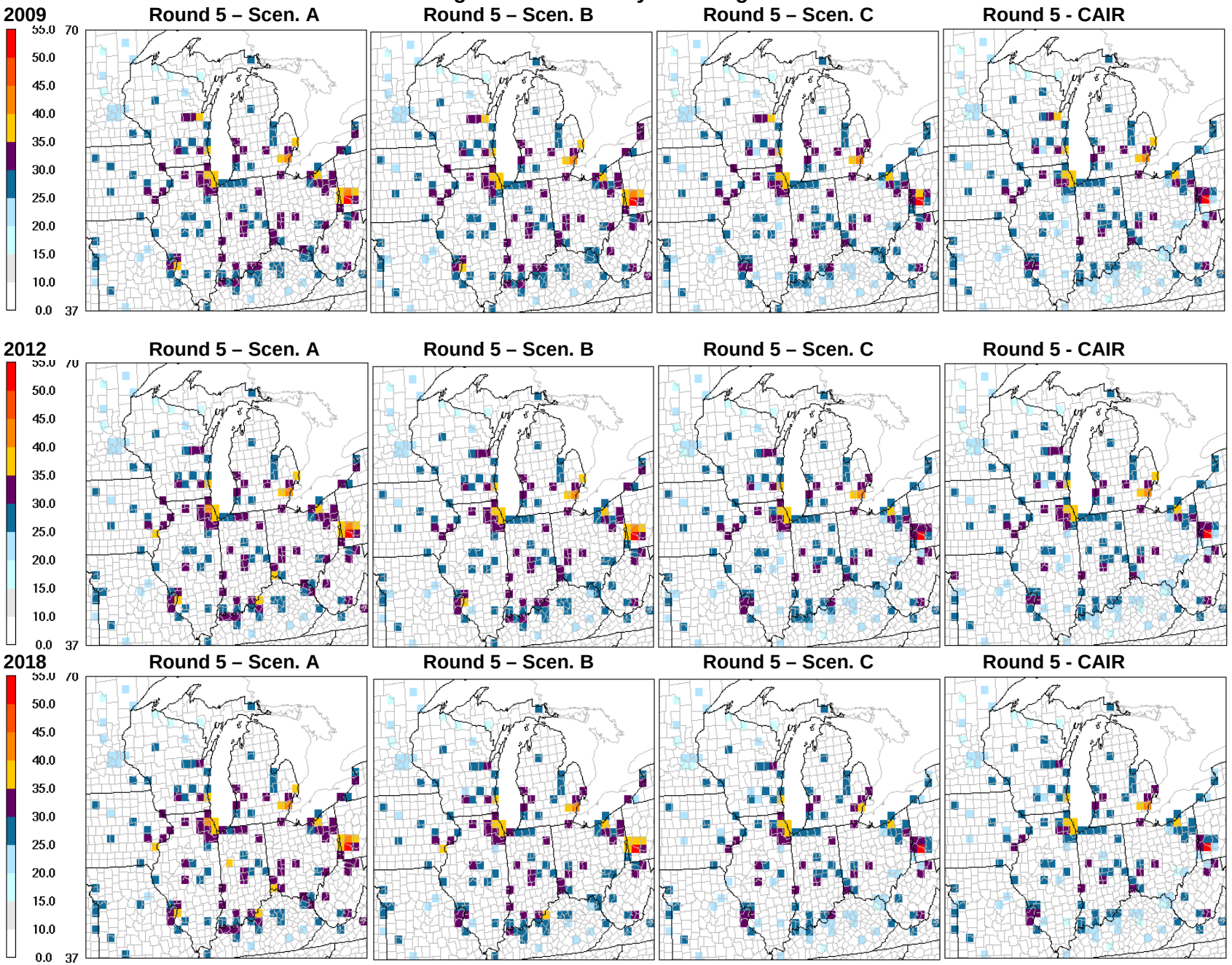


Figure 4. PM2.5 Daily Modeling Results



Appendix I

Scenario B (Legally Enforceable) Controls

NOx – 2009

Point Source Grown and Controlled Emissions by facility for NOX r6s1b_2009 Base Year = 2002

Future Year = 2009

STID=17 CYID=57 fcid=057801AAA name=AES DUCK CREEK

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	57	057801AAA	0001	0001	01	10100202	NOX	0.8147	0.8416	0.8416	0.00	0.00	SCR	SCR added by LADCO

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0001	0001	01	10100202	NOX	3.0515	3.1522	3.1522	0.00	0.00	lnb	LNB added by LADCO
17	143	143805AAG	0001	0003	01	10100202	NOX	6.9419	7.1708	7.1708	0.00	0.00	lnb	LNB added by LADCO
17	143	143805AAG	0002	0004	01	10100202	NOX	2.1310	2.2013	2.2013	0.00	0.00	lnb	LNB added by LADCO
----								--------	--------	----------				
fcid								12.1244	12.5243	12.5243				
cyid								12.1244	12.5243	12.5243				
stid								12.9392	13.3659	13.3659				

STID=39 CYID=1 fcid=0701000007 name="DP&L, J.M. STUART GENERATING STATION"

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	1	0701000007	R1	B001	B001P1	10100202	NOX	6.9860	6.9756	2.3252	0.85	0.95	SCR	SCR added by LADCO
39	1	0701000007	R2	B002	B002P1	10100202	NOX	3.6327	3.6273	1.2091	0.85	0.95	SCR	SCR added by LADCO
39	1	0701000007	R3	B003	B003P1	10100202	NOX	5.0133	5.0058	1.6686	0.85	0.95	SCR	SCR added by LADCO
39	1	0701000007	R4	B004	B004P1	10100202	NOX	7.8493	7.8376	2.6125	0.85	0.95	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								23.4814	23.4464	7.8155				
cyid								23.4814	23.4464	7.8155				

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	167	0684000000	R1	B001	B001P1	10200501	NOX	0.0017	0.0017	0.0001	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P1	10100201	NOX	5.8167	5.8080	0.2904	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	NOX	7.9017	7.8899	0.3945	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	NOX	7.8775	7.8657	0.3933	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	NOX	3.8586	3.8528	0.1926	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								25.4561	25.4182	1.2709				
cyid								25.4561	25.4182	1.2709				
stid								48.9375	48.8646	9.0864				

STID=55 CYID=79 fcid=241007800 name=WIS ELECTRIC POWER VALLEY STATION

Base Yr	Grown	Controlled	Base Year	Future Year

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007800	S11	B21	01	10100202	NOX	2.7972	2.8895	1.6470	0.00	0.43	SCR	SCR added by LADCO
55	79	241007800	S11	B22	01	10100202	NOX	2.9073	3.0032	1.7118	0.00	0.43	SCR	SCR added by LADCO
55	79	241007800	S12	B23	01	10100202	NOX	2.3270	2.4038	1.2740	0.00	0.47	SCR	SCR added by LADCO
55	79	241007800	S12	B24	01	10100202	NOX	2.3427	2.4199	1.2826	0.00	0.47	SCR	Scrubber added by LADCO
----								--------	--------	----------				
fcid								10.3742	10.7164	5.9154				
cyid								10.3742	10.7164	5.9154				

STID=55 CYID=117 fcid=460033090 name=WP & L Alliant Energy - Edgewater Gen Station

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
55	117	460033090	S11	B23	01	10100203	NOX	1.6197	1.6731	1.0038	0.00	0.40	SCR	SCR added by LADCO
55	117	460033090	S11	B24	01	10100203	NOX	4.1072	4.2426	3.4789	0.00	0.18	SCR	SCR added by LADCO
55	117	460033090	S12	B25	01	10100221	NOX	5.6804	5.8677	4.9876	0.00	0.15	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								11.4072	11.7834	9.4703				
cyid								11.4072	11.7834	9.4703				
stid								21.7814	22.4997	15.3857				
								========	========	==========				
								83.6581	84.7302	37.8380				

NOx - 2012

Point Source Grown and Controlled Emissions by facility for NOX r6s1b_2012 Base Year = 2002

Future Year = 2012

STID=17 CYID=33 fcid=033801AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	33	033801AAA	0005	0005	01	10100202	NOX	1.642	1.871	0.9357	0.00	0.500	SCR	SCR added by LADCO
17	33	033801AAA	0006	0006	01	10100202	NOX	2.116	2.413	1.2063	0.00	0.500	SCR	SCR added by LADCO
---								--------	--------	----------				
fcid								3.758	4.284	2.1420				
cyid								3.758	4.284	2.1420				

STID=17 CYID=57 fcid=057801AAA name=AES DUCK CREEK

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	57	057801AAA	0001	0001	01	10100202	NOX	0.815	0.929	0.9288	0.00	0.000	SCR	SCR added by LADCO

STID=17 CYID=79 fcid=079808AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	79	079808AAA	0003	0003	01	10100202	NOX	6.735	7.678	7.6780	0.00	0.000	SCR	SCR added by LADCO
17	79	079808AAA	0012	0013	01	10100501	NOX	5.936	5.378	5.3781	0.00	0.000	SCR	SCR added by LADCO
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fcid								12.671	13.056	13.0561				
cyid								12.671	13.056	13.0561				

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0016	0031	02	10100401	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO

STID=17 CYID=137 fcid=137805AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	137	137805AAA	0003	0003	01	10100202	NOX	5.356	6.106	6.1058	0.00	0.000	LNB	LNB added by LADCO

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0001	0001	01	10100202	NOX	3.052	3.479	3.4789	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0001	0003	01	10100202	NOX	6.942	7.914	7.9141	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0002	0004	01	10100202	NOX	2.131	2.429	2.4294	0.00	0.000	lnb	LNB added by LADCO
---								--------	--------	----------				
fcid								12.124	13.822	13.8224				
cyid								12.124	13.822	13.8224				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	NOX	6.527	7.441	0.0074	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
17	167	167120AAO	0010	0013	01	10100203	NOX	2.646	3.017	0.0030	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
----								--------	--------	----------				
fcid								9.173	10.458	0.0105				
cyid								9.173	10.458	0.0105				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	NOX	22.429	25.570	1.2785	0.00	0.950	SCR	SCR added by LADCO
17	179	179801AAA	0018	0031	01	10100203	NOX	38.993	44.454	2.2227	0.00	0.950	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								61.422	70.024	3.5012				
cyid								61.422	70.024	3.5012				

STID=17 CYID=197 fcid=197809AAO name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197809AAO	0032	0033	02	10100604	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197810AAK	0011	0016	02	10100222	NOX	5.731	6.534	3.9203	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0011	0016	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0013	0010	02	10100223	NOX	8.598	9.802	0.0098	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0013	0010	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	02	10100223	NOX	10.974	12.511	0.0125	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
----								--------	--------	----------				
fcid								25.303	28.847	3.9426				
cyid								25.303	28.847	3.9426				
stid								130.622	147.527	43.5096				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	NOX	13.661	14.142	2.8284	0.00	0.800	SCR	SCR added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								13.661	14.142	2.8284				
cyid								13.661	14.142	2.8284				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

27	109	2710900011	SV003	EU004	001	10100202	NOX	2.079	2.152	1.2911	0.00	0.400	SNCR	SCR added by LADCO
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stid								15.739	16.294	4.1195				

STID=39 CYID=1 fcid=0701000007 name="DP&L, J.M. STUART GENERATING STATION"

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	1	0701000007	R1	B001	B001P1	10100202	NOX	6.986	7.296	2.4319	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R2	B002	B002P1	10100202	NOX	3.633	3.794	1.2646	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R3	B003	B003P1	10100202	NOX	5.013	5.235	1.7452	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R4	B004	B004P1	10100202	NOX	7.849	8.197	2.7324	0.85	0.950	SCR	SCR added by LADCO
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fcid								23.481	24.522	8.1740				
cyid								23.481	24.522	8.1740				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	NOX	20.852	21.776	1.0888	0.00	0.950	SCR	SCR added by LADCO

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	167	0684000000	R1	B001	B001P1	10200501	NOX	0.002	0.002	0.0001	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P1	10100201	NOX	5.817	6.074	0.3037	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	NOX	7.902	8.252	0.4126	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	NOX	7.877	8.227	0.4113	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	NOX	3.859	4.030	0.2015	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
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fcid								25.456	26.584	1.3292				
cyid								25.456	26.584	1.3292				
stid								69.789	72.882	10.5920				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	NOX	4.755	5.421	3.0898	0.00	0.430	SCR	SCR added by LADCO
55	79	241007690	S13	B26	01	10100202	NOX	3.277	3.736	2.2045	0.00	0.410	SCR	SCR added by LADCO
55	79	241007690	S14	B27	01	10100212	NOX	3.333	3.800	2.8499	0.00	0.250	SCR	SCR added by LADCO
55	79	241007690	S14	B28	01	10100212	NOX	3.384	3.857	2.9316	0.00	0.240	SCR	SCR added by LADCO
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fcid								14.749	16.814	11.0757				

STID=55 CYID=79 fcid=241007800 name=WIS ELECTRIC POWER VALLEY STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Grown Tons/Day	Controlled Base Year Tons/Day	Future Year Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007800	S11	B21	01	10100202	NOX	2.797	3.189	1.8177	0.00	0.430	SCR	SCR added by LADCO
55	79	241007800	S11	B22	01	10100202	NOX	2.907	3.314	1.8893	0.00	0.430	SCR	SCR added by LADCO
55	79	241007800	S12	B23	01	10100202	NOX	2.327	2.653	1.4061	0.00	0.470	SCR	SCR added by LADCO
55	79	241007800	S12	B24	01	10100202	NOX	2.343	2.671	1.4155	0.00	0.470	SCR	Scrubber added by LADCO
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fcid								10.374	11.827	6.5285				
cyid								25.123	28.641	17.6042				

STID=55 CYID=117 fcid=460033090 name=WP & L Alliant Energy - Edgewater Gen Station

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Grown Tons/Day	Controlled Base Year Tons/Day	Future Year Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	117	460033090	S11	B23	01	10100203	NOX	1.620	1.846	1.1079	0.00	0.400	SCR	SCR added by LADCO
55	117	460033090	S11	B24	01	10100203	NOX	4.107	4.682	3.8395	0.00	0.180	SCR	SCR added by LADCO
55	117	460033090	S12	B25	01	10100221	NOX	5.680	6.476	5.5045	0.00	0.150	SCR	SCR added by LADCO
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fcid								11.407	13.005	10.4519				
cyid								11.407	13.005	10.4519				
stid								36.530	41.646	28.0562				
								========	========	==========				
								252.681	278.349	86.2773				

NOx 2018

Point Source Grown and Controlled Emissions by facility for NOX r6s1b_2018 Base Year = 2002

Future Year = 2018

STID=17 CYID=31 fcid=031600AIN name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AIN	0010	0013	01	10100226	NOX	2.283	2.592	1.5550	0.00	0.400	SCR	SCR added by LADCO
17	31	031600AIN	0010	0013	02	10100601	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
17	31	031600AIN	0012	0016	01	10100226	NOX	3.991	4.531	2.7184	0.00	0.400	SCR	SCR added by LADCO
17	31	031600AIN	0012	0016	02	10100601	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
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fcid								6.274	7.122	4.2734				
cyid								6.274	7.122	4.2734				

STID=17 CYID=33 fcid=033801AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	33	033801AAA	0005	0005	01	10100202	NOX	1.642	1.863	0.9317	0.00	0.500	SCR	SCR added by LADCO
17	33	033801AAA	0006	0006	01	10100202	NOX	2.116	2.402	1.2012	0.00	0.500	SCR	SCR added by LADCO
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fcid								3.758	4.266	2.1329				
cyid								3.758	4.266	2.1329				

STID=17 CYID=57 fcid=057801AAA name=AES DUCK CREEK

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	57	057801AAA	0001	0001	01	10100202	NOX	0.815	0.925	0.9249	0.00	0.000	SCR	SCR added by LADCO

STID=17 CYID=79 fcid=079808AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	79	079808AAA	0003	0003	01	10100202	NOX	6.735	7.645	7.6453	0.00	0.000	SCR	SCR added by LADCO
17	79	079808AAA	0012	0013	01	10100501	NOX	5.936	3.984	3.9838	0.00	0.000	SCR	SCR added by LADCO
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fcid								12.671	11.629	11.6291				
cyid								12.671	11.629	11.6291				

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0016	0031	02	10100401	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO

STID=17 CYID=137 fcid=137805AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	137	137805AAA	0003	0003	01	10100202	NOX	5.356	6.080	6.0798	0.00	0.000	LNB	LNB added by LADCO

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0001	0001	01	10100202	NOX	3.052	3.464	3.4641	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0001	0003	01	10100202	NOX	6.942	7.880	7.8804	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0002	0004	01	10100202	NOX	2.131	2.419	2.4191	0.00	0.000	lnb	LNB added by LADCO
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fcid								12.124	13.764	13.7636				
cyid								12.124	13.764	13.7636				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	NOX	6.527	7.410	0.0074	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
17	167	167120AAO	0010	0013	01	10100203	NOX	2.646	3.004	0.0030	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
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fcid								9.173	10.414	0.0104				
cyid								9.173	10.414	0.0104				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	NOX	22.429	25.462	1.2731	0.00	0.950	SCR	SCR added by LADCO
17	179	179801AAA	0018	0031	01	10100203	NOX	38.993	44.265	2.2132	0.00	0.950	SCR	SCR added by LADCO
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fcid								61.422	69.726	3.4863				
cyid								61.422	69.726	3.4863				

STID=17 CYID=197 fcid=197809AAO name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197809AAO	0032	0033	02	10100604	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197810AAK	0011	0016	02	10100222	NOX	5.731	6.506	3.9036	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0011	0016	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0013	0010	02	10100223	NOX	8.598	9.760	0.0098	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0013	0010	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	02	10100223	NOX	10.974	12.458	0.0125	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
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fcid								25.303	28.724	3.9258				
cyid								25.303	28.724	3.9258				
stid								136.896	152.649	46.2263				

STID=18 CYID=147 fcid=00020 name=INDIANA MICHIGAN POWER-ROCKPORT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
18	147	00020	1	001	01	10100222	NOX	23.226	25.291	1.2646	0.00	0.950	SCR	SCR added by LADCO
18	147	00020	1	001	02	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
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fcid								23.226	25.291	1.2646				
cyid								23.226	25.291	1.2646				
stid								23.226	25.291	1.2646				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	NOX	13.661	15.733	3.1466	0.00	0.800	SCR	SCR added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO
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fcid								13.661	15.733	3.1466				
cyid								13.661	15.733	3.1466				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	109	2710900011	SV003	EU004	001	10100202	NOX	2.079	2.394	1.4363	0.00	0.400	SNCR	SCR added by LADCO
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stid								15.739	18.127	4.5830				

STID=39 CYID=1 fcid=0701000007 name="DP&L, J.M. STUART GENERATING STATION"

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	1	0701000007	R1	B001	B001P1	10100202	NOX	6.986	7.607	2.5358	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R2	B002	B002P1	10100202	NOX	3.633	3.956	1.3186	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R3	B003	B003P1	10100202	NOX	5.013	5.459	1.8197	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R4	B004	B004P1	10100202	NOX	7.849	8.547	2.8491	0.85	0.950	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								23.481	25.570	8.5232				
cyid								23.481	25.570	8.5232				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	NOX	20.852	22.706	1.1353	0.00	0.950	SCR	SCR added by LADCO

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	167	0684000000	R1	B001	B001P1	10200501	NOX	0.002	0.002	0.0001	0.00	0.950	SCR	SCR added by LADCO

39	167	0684000000	R2	B002	B002P1	10100201	NOX	5.817	6.334	0.3167	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	NOX	7.902	8.604	0.4302	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	NOX	7.877	8.578	0.4289	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	NOX	3.859	4.202	0.2101	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
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fcid								25.456	27.720	1.3860				
cyid								25.456	27.720	1.3860				
stid								69.789	75.996	11.0445				

STID=54 CYID=39 fcid=0006 name=APPALACHIAN POWER - KANAWHA RIVER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	39	0006	012	001	99	10100202	NOX	4.829	5.258	2.6291	0.00	0.500	SCR	Scrubber added by LADCO
54	39	0006	012	002	99	10100202	NOX	4.921	5.359	2.6794	0.00	0.500	SCR	Scrubber added by LADCO
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fcid								9.750	10.617	5.3085				
cyid								9.750	10.617	5.3085				
stid								9.750	10.617	5.3085				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	NOX	4.755	5.398	3.0766	0.00	0.430	SCR	SCR added by LADCO
55	79	241007690	S13	B26	01	10100202	NOX	3.277	3.720	2.1951	0.00	0.410	SCR	SCR added by LADCO
55	79	241007690	S14	B27	01	10100212	NOX	3.333	3.784	2.8378	0.00	0.250	SCR	SCR added by LADCO
55	79	241007690	S14	B28	01	10100212	NOX	3.384	3.841	2.9191	0.00	0.240	SCR	SCR added by LADCO
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fcid								14.749	16.743	11.0285				

STID=55 CYID=79 fcid=241007800 name=WIS ELECTRIC POWER VALLEY STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007800	S11	B21	01	10100202	NOX	2.797	3.175	1.4289	0.00	0.550	SCR	SCR added by LADCO
55	79	241007800	S11	B22	01	10100202	NOX	2.907	3.300	1.4852	0.00	0.550	SCR	SCR added by LADCO
55	79	241007800	S12	B23	01	10100202	NOX	2.327	2.642	1.1887	0.00	0.550	SCR	SCR added by LADCO
55	79	241007800	S12	B24	01	10100202	NOX	2.343	2.659	1.1967	0.00	0.550	SCR	SCR added by LADCO
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fcid								10.374	11.777	5.2995				
cyid								25.123	28.519	16.3281				

STID=55 CYID=117 fcid=460033090 name=WP & L Alliant Energy - Edgewater Gen Station

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	117	460033090	S11	B23	01	10100203	NOX	1.620	1.839	1.1032	0.00	0.400	SCR	SCR added by LADCO

55	117	460033090	S11	B24	01	10100203	NOX	4.107	4.662	3.8232	0.00	0.180	SCR	SCR added by LADCO
55	117	460033090	S12	B25	01	10100221	NOX	5.680	6.448	5.4811	0.00	0.150	SCR	SCR added by LADCO
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fcid						11.407	12.949	10.4074						
cyid						11.407	12.949	10.4074						
stid						36.530	41.469	26.7355						
						========	========	==========						
						291.931	324.149	95.1624						

SO2 – 2009

Point Source Grown and Controlled Emissions by facility for SO2 r6s1b_2009

Base Year = 2002

Future Year = 2009

STID=19 CYID=115 fcid=58-07-001 name=MIDAMERICAN ENERGY CO. - LOUISA STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
19	115	58-07-001	117487	147281	99	10100222	SO2	33.664	34.774	3.4774	0.0	0.90	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=161 fcid=2116100009 name=EAST KY POWER COOP

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
21	161	2116100009	1	001	99	10100202	SO2	42.166	42.103	4.2103	0.0	0.90	SCRUBBER	Scrubber added by LADCO
21	161	2116100009	2	002	99	10100212	SO2	55.385	55.303	5.5303	0.0	0.90	SCRUBBER	Scrubber added by LADCO
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fcid								97.551	97.406	9.7406				
cyid								97.551	97.406	9.7406				
stid								97.551	97.406	9.7406				

STID=27 CYID=141 fcid=2714100004 name=NSP - Sherburne Generating Plant

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	141	2714100004	SV001	EU001	001	10100222	SO2	16.765	16.987	3.6401	0.3	0.85	SCRUBBER	Scrubber added by LADCO
27	141	2714100004	SV001	EU002	001	10100222	SO2	22.549	22.848	4.8959	0.3	0.85	SCRUBBER	Scrubber added by LADCO
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fcid								39.314	39.834	8.5360				
cyid								39.314	39.834	8.5360				
stid								39.314	39.834	8.5360				

STID=54 CYID=51 fcid=0005 name=OHIO POWER - MITCHELL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0005	012	001	99	10100202	SO2	17.775	17.748	1.7748	0.0	0.90	SCRUBBER	Scrubber added by LADCO
54	51	0005	012	002	99	10100202	SO2	5.689	5.680	0.5680	0.0	0.90	SCRUBBER	Scrubber added by LADCO
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fcid								23.463	23.428	2.3428				
cyid								23.463	23.428	2.3428				

STID=54 CYID=53 fcid=0009 name=APPALACHIAN POWER - MOUNTAINEER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	53	0009	001	001	99	10100202	SO2	11.196	11.179	1.1179	0.0	0.90	SCRUBBER	Scrubber added by LADCO

STID=54 CYID=79 fcid=0006 name=APPALACHIAN POWER - JOHN E AMOS PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

54	79	0006	012	001	99	10100202	SO2	79.635	79.516	7.9516	0.0	0.90	SCRUBBER Scrubber added by LADCO
54	79	0006	003	003	99	10100202	SO2	139.377	139.169	13.9169	0.0	0.90	SCRUBBER Scrubber added by LADCO

fcid	219.012	218.685	21.8685
cyid	219.012	218.685	21.8685
stid	253.671	253.293	25.3293
	424.200	425.307	47.0832

SO2 – 2012

Point Source Grown and Controlled Emissions by facility for SO2 r6s1b_2012

Base Year = 2002

Future Year = 2012

STID=17 CYID=31 fcid=031600AMI name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AMI	0007	0010	01	10100226	SO2	16.13	18.39	1.839	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0018	0033	01	10100226	SO2	24.14	27.52	2.752	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0021	0036	01	10100226	SO2	19.23	21.92	2.192	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0016	0031	01	10100203	SO2	4.59	5.24	0.005	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								47.96	54.68	4.950				
cyid								47.96	54.68	4.950				

STID=17 CYID=125 fcid=125804AAB name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	125	125804AAB	0019	0023	01	10100202	SO2	22.34	25.47	3.821	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=127 fcid=127855AAC name=ELECTRIC ENERGY INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	127	127855AAC	0001	0001	01	10100222	SO2	11.83	13.48	13.482	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0001	0002	01	10100222	SO2	11.48	13.09	13.085	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0002	0003	01	10100222	SO2	10.25	11.68	11.680	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0002	0004	01	10100222	SO2	12.04	13.73	13.731	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0003	0006	01	10100222	SO2	12.68	14.46	14.456	0.0	0.000	LNB	LNB added by LADCO
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fcid								58.27	66.43	66.435				
cyid								58.27	66.43	66.435				

STID=17 CYID=135 fcid=135803AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	135	135803AAA	0001	0001	01	10100203	SO2	32.99	37.61	3.761	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	135	135803AAA	0001	0003	01	10100203	SO2	72.92	83.13	8.313	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								105.91	120.74	12.074				
cyid								105.91	120.74	12.074				

STID=17 CYID=157 fcid=157851AAA name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	157	157851AAA	0001	0001	01	10100203	SO2	25.14	28.66	4.299	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0002	0002	01	10100203	SO2	25.79	29.41	4.411	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0013	0013	01	10100202	SO2	27.79	31.68	4.752	0.0	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								78.72	89.75	13.462				
cyid								78.72	89.75	13.462				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	SO2	44.20	50.39	0.050	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	167	167120AAO	0010	0013	01	10100203	SO2	16.40	18.70	0.019	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								60.61	69.10	0.069				
cyid								60.61	69.10	0.069				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	SO2	25.35	28.90	2.890	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	179	179801AAA	0018	0031	01	10100203	SO2	41.57	47.39	4.739	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.91	76.29	7.629				
cyid								66.91	76.29	7.629				

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197810AAK	0013	0010	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	02	10100223	SO2	15.33	17.48	0.017	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								15.33	17.48	0.017				
cyid								15.33	17.48	0.017				
stid								472.19	538.32	110.295				

STID=19 CYID=115 fcid=58-07-001 name=MIDAMERICAN ENERGY CO. - LOUISA STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
19	115	58-07-001	117487	147281	99	10100222	SO2	33.66	38.38	3.838	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=161 fcid=2116100009 name=EAST KY POWER COOP

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

21	161	2116100009	1	001	99	10100202	SO2	42.17	44.03	4.403	0.0	0.900	SCRUBBER	Scrubber added by LADCO
21	161	2116100009	2	002	99	10100212	SO2	55.39	57.84	5.784	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								97.55	101.87	10.187				
cyid								97.55	101.87	10.187				
stid								97.55	101.87	10.187				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	SO2	33.99	35.19	15.081	0.3	0.700	SCRUBBER	Scrubber added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	SO2	0.00	0.00	0.000	0.3	0.700	SCRUBBER	Scrubber added by LADCO
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fcid								33.99	35.19	15.081				
cyid								33.99	35.19	15.081				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	109	2710900011	SV003	EU004	001	10100202	SO2	7.86	8.13	1.220	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=27 CYID=141 fcid=2714100004 name=NSP - Sherburne Generating Plant

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	141	2714100004	SV001	EU001	001	10100222	SO2	16.76	17.36	3.719	0.3	0.850	SCRUBBER	Scrubber added by LADCO
27	141	2714100004	SV001	EU002	001	10100222	SO2	22.55	23.34	5.002	0.3	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								39.31	40.70	8.721				
cyid								39.31	40.70	8.721				
stid								81.16	84.02	25.023				

STID=39 CYID=13 fcid=0607130015 name=R. E. BURGER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	13	0607130015	R6	B011	B011P1	10100202	SO2	29.83	31.15	3.115	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	13	0607130015	R7	B012	B012P1	10100202	SO2	34.77	36.31	3.631	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								64.60	67.46	6.746				
cyid								64.60	67.46	6.746				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	SO2	316.00	330.00	33.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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stid								380.60	397.46	39.746				

STID=47 CYID=1 fcid=0009 name=TVA BULL RUN FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	1	0009	S-1	001	99	10100212	SO2	130.81	133.01	13.301	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=47 CYID=73 fcid=0007 name=TVA JOHN SEVIER FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	73	0007	S-1A	001	99	10100212	SO2	20.15	20.49	2.049	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-1B	002	99	10100212	SO2	20.25	20.59	2.059	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2A	003	99	10100212	SO2	19.62	19.95	1.995	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2B	004	99	10100212	SO2	18.93	19.25	1.925	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								78.95	80.28	8.028				
cyid								78.95	80.28	8.028				

STID=47 CYID=85 fcid=0011 name=TVA JOHNSONVILLE FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	85	0011	S1-01	001	99	10100212	SO2	17.06	17.35	1.735	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-04	004	99	10100212	SO2	19.85	20.18	2.018	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-05	005	99	10100212	SO2	24.11	24.52	2.452	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								61.02	62.04	6.204				
cyid								61.02	62.04	6.204				

STID=47 CYID=145 fcid=0013 name=TVA KINGSTON FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	145	0013	S-1	001	99	10100202	SO2	12.68	12.89	1.289	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	002	99	10100202	SO2	14.00	14.24	1.424	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	003	99	10100202	SO2	13.80	14.04	1.404	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	004	99	10100202	SO2	12.24	12.44	1.244	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	005	99	10100202	SO2	19.57	19.90	1.990	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	006	99	10100202	SO2	18.92	19.24	1.924	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	007	99	10100202	SO2	21.30	21.66	2.166	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	008	99	10100202	SO2	18.54	18.85	1.885	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	009	99	10100202	SO2	20.72	21.07	2.107	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								151.77	154.33	15.433				
cyid								151.77	154.33	15.433				

STID=47 CYID=165 fcid=0025 name=TVA GALLATIN FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	165	0025	S-01	001	99	10100212	SO2	13.91	14.14	1.414	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-01	002	99	10100212	SO2	14.87	15.12	1.512	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	003	99	10100212	SO2	16.33	16.60	1.660	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	004	99	10100212	SO2	20.39	20.73	2.073	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								65.49	66.59	6.659				
cyid								65.49	66.59	6.659				
stid								488.04	496.25	49.625				

STID=54 CYID=51 fcid=0005 name=OHIO POWER - MITCHELL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0005	012	001	99	10100202	SO2	17.77	18.56	1.856	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0005	012	002	99	10100202	SO2	5.69	5.94	0.594	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								23.46	24.50	2.450				
cyid								23.46	24.50	2.450				

STID=54 CYID=53 fcid=0009 name=APPALACHIAN POWER - MOUNTAINEER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	53	0009	001	001	99	10100202	SO2	11.20	11.69	1.169	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=54 CYID=79 fcid=0006 name=APPALACHIAN POWER - JOHN E AMOS PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	79	0006	012	001	99	10100202	SO2	79.63	83.16	8.316	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	012	002	99	10100202	SO2	100.33	104.78	10.478	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	003	003	99	10100202	SO2	139.38	145.55	14.555	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								319.35	333.50	33.350				
cyid								319.35	333.50	33.350				
stid								354.00	369.69	36.969				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	SO2	12.75	14.54	3.490	0.0	0.760	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S13	B26	01	10100202	SO2	8.68	9.89	2.473	0.0	0.750	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B27	01	10100212	SO2	10.97	12.51	2.876	0.0	0.770	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B28	01	10100212	SO2	11.28	12.86	2.958	0.0	0.770	SCRUBBER	Scrubber added by LADCO
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fcid								43.68	49.80	11.797				
cyid								43.68	49.80	11.797				
stid								43.68	49.80	11.797				
								========	========	==========				
								1950.90	2075.80	287.480				

SO2 – 2018

Point Source Grown and Controlled Emissions by facility for SO2 r6s1b_2018

Base Year = 2002

Future Year = 2018

STID=17 CYID=31 fcid=031600AIN name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AIN	0010	0013	01	10100226	SO2	10.92	12.39	1.239	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	31	031600AIN	0012	0016	01	10100226	SO2	17.69	20.08	2.008	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								28.61	32.48	3.248				

STID=17 CYID=31 fcid=031600AMI name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AMI	0007	0010	01	10100226	SO2	16.13	18.31	1.831	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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cyid								44.74	50.79	5.079				

STID=17 CYID=79 fcid=079808AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	79	079808AAA	0003	0003	01	10100202	SO2	36.35	41.27	4.127	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	79	079808AAA	0012	0013	01	10100501	SO2	28.99	19.46	1.946	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								65.34	60.72	6.072				
cyid								65.34	60.72	6.072				

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0018	0033	01	10100226	SO2	24.14	27.40	2.740	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0021	0036	01	10100226	SO2	19.23	21.83	2.183	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0016	0031	01	10100203	SO2	4.59	5.22	0.005	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								47.96	54.45	4.928				
cyid								47.96	54.45	4.928				

STID=17 CYID=125 fcid=125804AAB name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	125	125804AAB	0019	0023	01	10100202	SO2	22.34	25.36	3.805	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=127 fcid=127855AAC name=ELECTRIC ENERGY INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

17	127	127855AAC	0002	0003	01	10100222	SO2	10.25	11.63	11.630	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0002	0004	01	10100222	SO2	12.04	13.67	13.673	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0001	0001	01	10100222	SO2	11.83	13.42	1.342	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	127	127855AAC	0001	0002	01	10100222	SO2	11.48	13.03	1.303	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	127	127855AAC	0003	0005	01	10100222	SO2	11.72	13.31	1.331	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	127	127855AAC	0003	0006	01	10100222	SO2	12.68	14.39	1.439	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								70.00	79.46	30.719				
cyid								70.00	79.46	30.719				

STID=17 CYID=135 fcid=135803AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	135	135803AAA	0001	0001	01	10100203	SO2	32.99	37.45	3.745	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	135	135803AAA	0001	0003	01	10100203	SO2	72.92	82.77	8.277	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								105.91	120.22	12.022				
cyid								105.91	120.22	12.022				

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0002	0004	01	10100202	SO2	15.28	17.34	1.734	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=157 fcid=157851AAA name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	157	157851AAA	0001	0001	01	10100203	SO2	25.14	28.54	4.281	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0002	0002	01	10100203	SO2	25.79	29.28	4.392	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0013	0013	01	10100202	SO2	27.79	31.54	4.732	0.0	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								78.72	89.36	13.404				
cyid								78.72	89.36	13.404				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	SO2	44.20	50.18	0.050	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	167	167120AAO	0010	0013	01	10100203	SO2	16.40	18.62	0.019	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								60.61	68.80	0.069				
cyid								60.61	68.80	0.069				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	SO2	25.35	28.77	2.877	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	179	179801AAA	0018	0031	01	10100203	SO2	41.57	47.19	4.719	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.91	75.96	7.596				
cyid								66.91	75.96	7.596				

STID=17 CYID=197 fcid=197809AAO name=MIDWEST GENERATION LLC

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
17	197	197809AAO	0006	0009	01	10100203	SO2	15.89	18.04	1.804	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197809AAO	0016	0031	01	10100202	SO2	27.43	31.13	3.113	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197809AAO	0017	0033	01	10100202	SO2	23.13	26.26	2.626	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.45	75.44	7.544				

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
17	197	197810AAK	0009	0014	02	10100222	SO2	11.64	13.21	1.321	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197810AAK	0011	0016	02	10100222	SO2	25.67	29.14	2.914	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197810AAK	0013	0010	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	02	10100223	SO2	15.33	17.40	0.017	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								52.64	59.75	4.252				
cyid								119.09	135.19	11.796				
stid								696.90	777.66	97.225				

STID=18 CYID=147 fcid=00020 name=INDIANA MICHIGAN POWER-ROCKPORT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
18	147	00020	1	001	01	10100222	SO2	66.42	72.32	7.232	0.0	0.900	SCRUBBER	Scrubber added by LADCO
18	147	00020	1	001	02	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.42	72.32	7.232				
cyid								66.42	72.32	7.232				
stid								66.42	72.32	7.232				

STID=19 CYID=115 fcid=58-07-001 name=MIDAMERICAN ENERGY CO. - LOUISA STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
19	115	58-07-001	117487	147281	99	10100222	SO2	33.66	38.22	3.822	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=127 fcid=2112700003 name=KENTUCKY POWER CO

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
21	127	2112700003	2	002	99	10100202	SO2	104.52	113.82	11.382	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=161 fcid=2116100009 name=EAST KY POWER COOP

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes

21	161	2116100009	1	001	99	10100202	SO2	42.17	45.92	4.592	0.0	0.900	SCRUBBER	Scrubber added by LADCO
21	161	2116100009	2	002	99	10100212	SO2	55.39	60.31	6.031	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								97.55	106.23	10.623				
cyid								97.55	106.23	10.623				
stid								202.07	220.04	22.004				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	SO2	33.99	39.15	16.778	0.3	0.700	SCRUBBER	Scrubber added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	SO2	0.00	0.00	0.000	0.3	0.700	SCRUBBER	Scrubber added by LADCO
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fcid								33.99	39.15	16.778				
cyid								33.99	39.15	16.778				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
27	109	2710900011	SV003	EU004	001	10100202	SO2	7.86	9.05	1.357	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=27 CYID=141 fcid=2714100004 name=NSP - Sherburne Generating Plant

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
27	141	2714100004	SV001	EU001	001	10100222	SO2	16.76	19.31	4.138	0.3	0.850	SCRUBBER	Scrubber added by LADCO
27	141	2714100004	SV001	EU002	001	10100222	SO2	22.55	25.97	5.565	0.3	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								39.31	45.28	9.703				
cyid								39.31	45.28	9.703				
stid								81.16	93.48	27.838				

STID=39 CYID=13 fcid=0607130015 name=R. E. BURGER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
39	13	0607130015	R6	B011	B011P1	10100202	SO2	29.83	32.48	3.248	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	13	0607130015	R7	B012	B012P1	10100202	SO2	34.77	37.86	3.786	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								64.60	70.34	7.034				
cyid								64.60	70.34	7.034				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	SO2	316.00	344.11	34.411	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes

39	167	0684000000	R2	B002	B002P1	10100201	SO2	65.07	70.85	7.085	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	SO2	94.58	103.00	10.300	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	SO2	81.64	88.90	8.890	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R5	B005	B005P1	10100203	SO2	97.22	105.87	10.587	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R5	B005	B005P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	SO2	113.96	124.10	12.410	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								452.48	492.72	49.272				
cyid								452.48	492.72	49.272				
stid								833.08	907.16	90.716				

STID=47 CYID=1 fcid=0009 name=TVA BULL RUN FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	1	0009	S-1	001	99	10100212	SO2	130.81	136.82	13.682	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=47 CYID=73 fcid=0007 name=TVA JOHN SEVIER FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	73	0007	S-1A	001	99	10100212	SO2	20.15	21.07	2.107	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-1B	002	99	10100212	SO2	20.25	21.18	2.118	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2A	003	99	10100212	SO2	19.62	20.52	2.052	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2B	004	99	10100212	SO2	18.93	19.80	1.980	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								78.95	82.57	8.257				
cyid								78.95	82.57	8.257				

STID=47 CYID=85 fcid=0011 name=TVA JOHNSONVILLE FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	85	0011	S1-01	001	99	10100212	SO2	17.06	17.84	1.784	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-04	004	99	10100212	SO2	19.85	20.76	2.076	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-05	005	99	10100212	SO2	24.11	25.22	2.522	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								61.02	63.82	6.382				
cyid								61.02	63.82	6.382				

STID=47 CYID=145 fcid=0013 name=TVA KINGSTON FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	145	0013	S-1	001	99	10100202	SO2	12.68	13.26	1.326	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	002	99	10100202	SO2	14.00	14.65	1.465	0.0	0.900	SCRUBBER	Scrubber added by LADCO

47	145	0013	S-1	003	99	10100202	SO2	13.80	14.44	1.444	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	004	99	10100202	SO2	12.24	12.80	1.280	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	005	99	10100202	SO2	19.57	20.47	2.047	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	006	99	10100202	SO2	18.92	19.79	1.979	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	007	99	10100202	SO2	21.30	22.28	2.228	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	008	99	10100202	SO2	18.54	19.39	1.939	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	009	99	10100202	SO2	20.72	21.68	2.168	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								151.77	158.75	15.875				
cyid								151.77	158.75	15.875				

STID=47 CYID=165 fcid=0025 name=TVA GALLATIN FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	165	0025	S-01	001	99	10100212	SO2	13.91	14.54	1.454	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-01	002	99	10100212	SO2	14.87	15.56	1.556	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	003	99	10100212	SO2	16.33	17.08	1.708	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	004	99	10100212	SO2	20.39	21.32	2.132	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								65.49	68.50	6.850				
cyid								65.49	68.50	6.850				
stid								488.04	510.46	51.046				

STID=54 CYID=39 fcid=0006 name=APPALACHIAN POWER - KANAWHA RIVER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	39	0006	012	001	99	10100202	SO2	19.45	21.18	10.591	0.0	0.500	SCRUBBER	Scrubber added by LADCO
54	39	0006	012	002	99	10100202	SO2	20.94	22.80	11.399	0.0	0.500	SCRUBBER	Scrubber added by LADCO
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fcid								40.39	43.98	21.990				
cyid								40.39	43.98	21.990				

STID=54 CYID=51 fcid=0005 name=OHIO POWER - MITCHELL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0005	012	001	99	10100202	SO2	17.77	19.36	1.936	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0005	012	002	99	10100202	SO2	5.69	6.19	0.619	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								23.46	25.55	2.555				

STID=54 CYID=51 fcid=0006 name=OHIO POWER - KAMMER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0006	013	001	99	10100203	SO2	47.06	51.25	5.125	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0006	013	002	99	10100203	SO2	47.66	51.90	5.190	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0006	013	003	99	10100203	SO2	41.94	45.67	4.567	0.0	0.900	SCRUBBER	Scrubber added by LADCO

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fcid								136.67	148.82	14.882				
cyid								160.13	174.37	17.437				

STID=54 CYID=53 fcid=0001 name=APPALACHIAN POWER CO.-PHILIP SPORN PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	53	0001	014	001	99	10100202	SO2	18.65	20.31	2.031	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	014	002	99	10100202	SO2	15.87	17.28	1.728	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	014	003	99	10100202	SO2	21.46	23.36	2.336	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	014	004	99	10100202	SO2	20.53	22.36	2.236	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	005	005	99	10100202	SO2	46.82	50.98	5.098	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								123.33	134.30	13.430				

STID=54 CYID=53 fcid=0009 name=APPALACHIAN POWER - MOUNTAINEER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	53	0009	001	001	99	10100202	SO2	11.20	12.19	1.219	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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cyid								134.53	146.49	14.649				

STID=54 CYID=79 fcid=0006 name=APPALACHIAN POWER - JOHN E AMOS PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	79	0006	012	001	99	10100202	SO2	79.63	86.72	8.672	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	012	002	99	10100202	SO2	100.33	109.26	10.926	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	003	003	99	10100202	SO2	139.38	151.77	15.177	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								319.35	347.75	34.775				
cyid								319.35	347.75	34.775				
stid								654.39	712.59	88.851				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	SO2	12.75	14.48	3.475	0.0	0.760	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S13	B26	01	10100202	SO2	8.68	9.85	2.462	0.0	0.750	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B27	01	10100212	SO2	10.97	12.45	2.864	0.0	0.770	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B28	01	10100212	SO2	11.28	12.81	2.945	0.0	0.770	SCRUBBER	Scrubber added by LADCO
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fcid								43.68	49.59	11.746				
cyid								43.68	49.59	11.746				
stid								43.68	49.59	11.746				
								========	========	==========				
								3099.41	3381.52	400.481				

Appendix II

Scenario C Controls (CAMD List)

NOx Controls (SCRs, 2007 – 2013))

Plant Name	UniqueID_Final	State Name	County	Capacity MW	On Line Year	SCR Online Year
Chesterfield	3797_B_4	Virginia	Chesterfield	166	1960	2013
Chesterfield	3797_B_5	Virginia	Chesterfield	310	1964	2012
Scherer	6257_B_3	Georgia	Monroe	875	1987	2011
Chesterfield	3797_B_6	Virginia	Chesterfield	658	1969	2011
Sandow No 4	6648_B_4	Texas	Milam	545	1981	2011
Beech Hollow Power Project	82704_B_1	Pennsylvania	Washington	272	2011	2011
Longview Power	82702_B_1	West Virginia	Monongalia	695	2011	2011
Cliffside	2721_B_6	North Carolina	Cleveland	800	2011	2011
AES Westover	2526_B_11	New York	Broome	22	1943	2010
AES Westover	2526_B_12	New York	Broome	22	1943	2010
AES Westover	2526_B_13	New York	Broome	84	1951	2010
Iatan 2	6065_B_2	Missouri	Platte	850	2010	2010
Southwest	6195_B_2	Missouri	Greene	300	2010	2010
Trimble Station (LGE)	6071_B_2	Kentucky	Trimble	732	2010	2010
Elm Road Generating Station	56068_B_2	Wisconsin	Milwaukee	615	2010	2010
Clay Boswell	1893_B_3	Minnesota	Itasca	350	1973	2009
Asheville	2706_B_2	North Carolina	Buncombe	184	1971	2009
Conesville	2840_B_4	Ohio	Coshocton	780	1973	2009
Marshall	2727_B_3	North Carolina	Catawba	657	1969	2009
St Johns River Power Park	207_B_1	Florida	Duval	626	1987	2009
Ghent	1356_B_2	Kentucky	Carroll	469	1977	2009
Chalk Point LLC	1571_B_1	Maryland	Prince George's	341	1964	2009
Chalk Point LLC	1571_B_2	Maryland	Prince George's	342	1965	2009
San Juan	2451_B_2	New Mexico	San Juan	320	1973	2009
Big Bend	645_B_BB01	Florida	Hillsborough	411	1970	2009
Big Bend	645_B_BB02	Florida	Hillsborough	391	1973	2009
Big Bend	645_B_BB03	Florida	Hillsborough	414	1976	2009
Nebraska City Unit 2	6096_B_2	Nebraska	Otoe	663	2009	2009
Cross	130_B_4	South Carolina	Berkeley	652	2009	2009
Springerville	8223_B_4	Arizona	Apache	400	2009	2009
Sandow 5	82010_B_5	Texas	Milam	600	2009	2009
Oak Grove	82011_B_1	Texas	Robertson	800	2009	2009
Oak Grove	82011_B_2	Texas	Robertson	800	2009	2009
TS Power Plant	82013_B_1	Nevada	Eureka	200	2009	2009
Plum Point Energy	82014_B_1	Arkansas	Mississippi	665	2009	2009
Comanche	470_B_3	Colorado	Pueblo	750	2009	2009
Elm Road Generating Station	56068_B_1	Wisconsin	Milwaukee	615	2009	2009
Two Elk Generating Station	55360_B_1	Wyoming	Campbell	300	2009	2009
J K Spruce	7097_B_BLR2	Texas	Bexar	750	2009	2009
Dallman	963_B_34	Illinois	Sangamon	200	2009	2009
AES Greenidge LLC	2527_B_4	New York	Yates	27	1950	2008
AES Greenidge LLC	2527_B_5	New York	Yates	27	1950	2008
AES Greenidge LLC	2527_B_6	New York	Yates	106	1953	2008
Charles R Lowman	56_B_2	Alabama	Washington	238	1979	2008
Charles R Lowman	56_B_3	Alabama	Washington	238	1980	2008
Barry	3_B_5	Alabama	Mobile	750	1971	2008
St Johns River Power Park	207_B_2	Florida	Duval	626	1988	2008
Morgantown Generating Plant	1573_B_2	Maryland	Charles	620	1971	2008

Bailly	995_B_7	Indiana	Porter	160	1962	2008
San Juan	2451_B_1	New Mexico	San Juan	322	1976	2008
San Juan	2451_B_3	New Mexico	San Juan	495	1979	2008
Weston	4078_B_4	Wisconsin	Marathon	519	2008	2008
AES Deepwater	10670_B_AAB001	Texas	Harris	140	1986	2007
La Cygne	1241_B_1	Kansas	Linn	724	1973	2007
Morgantown Generating Plant	1573_B_1	Maryland	Charles	624	1970	2007
PSEG Hudson Generating Station	2403_B_2	New Jersey	Hudson	583	1967	2007
San Juan	2451_B_4	New Mexico	San Juan	506	1982	2007
Big Bend	645_B_BB04	Florida	Hillsborough	457	1985	2007
Cross	130_B_3	South Carolina	Berkeley	620	2007	2007
Wygen II	55479_B_4	Wyoming	Campbell	90	2007	2007
Council Bluffs	1082_B_4	Iowa	Pottawattamie	790	2007	2007

SO2 Controls (FGDs, 2007 – 2012)

Plant Name	UniqueID_Final	State Name	County	Capacity MW	On Line Year	Scrubber Online Year
James H Miller Jr	6002_B_1	Alabama	Jefferson	684	1978	2011
James H Miller Jr	6002_B_2	Alabama	Jefferson	687	1985	2011
James H Miller Jr	6002_B_3	Alabama	Jefferson	687	1989	2011
James H Miller Jr	6002_B_4	Alabama	Jefferson	688	1991	2011
Cape Fear	2708_B_5	North Carolina	Chatham	143	1956	2011
Baldwin Energy Complex	889_B_1	Illinois	Randolph	624	1970	2011
Baldwin Energy Complex	889_B_2	Illinois	Randolph	629	1973	2011
Baldwin Energy Complex	889_B_3	Illinois	Randolph	629	1975	2011
Scherer	6257_B_3	Georgia	Monroe	875	1987	2011
Milton R Young	2823_B_B1	North Dakota	Oliver	250	1970	2011
W H Sammis	2866_B_6	Ohio	Jefferson	630	1969	2011
W H Sammis	2866_B_7	Ohio	Jefferson	630	1971	2011
PSEG Hudson Generating Station	2403_B_2	New Jersey	Hudson	583	1967	2011
John Sevier	3405_B_1	Tennessee	Hawkins	176	1955	2011
John Sevier	3405_B_2	Tennessee	Hawkins	176	1955	2011
John Sevier	3405_B_3	Tennessee	Hawkins	176	1956	2011
John Sevier	3405_B_4	Tennessee	Hawkins	176	1957	2011
Beech Hollow Power Project	82704_B_1	Pennsylvania	Washington	272	2011	2011
Longview Power	82702_B_1	West Virginia	Monongalia	695	2011	2011
Cliffside	2721_B_6	North Carolina	Cleveland	800	2011	2011
AES Greenidge LLC	2527_B_4	New York	Yates	27	1950	2010
AES Greenidge LLC	2527_B_5	New York	Yates	27	1950	2010
Barry	3_B_5	Alabama	Mobile	750	1971	2010
E C Gaston	26_B_5	Alabama	Shelby	861	1974	2010
Warrick	6705_B_4	Indiana	Warrick	300	1970	2010
Coffeen	861_B_01	Illinois	Montgomery	340	1965	2010
Coffeen	861_B_02	Illinois	Montgomery	560	1972	2010
Cardinal	2828_B_3	Ohio	Jefferson	630	1977	2010
Brandon Shores	602_B_1	Maryland	Anne Arundel	643	1984	2010
Brandon Shores	602_B_2	Maryland	Anne Arundel	643	1991	2010
Monroe	1733_B_4	Michigan	Monroe	775	1974	2010
Cliffside	2721_B_5	North Carolina	Cleveland	550	1972	2010
Crystal River	628_B_4	Florida	Citrus	720	1982	2010
Bowen	703_B_1BLR	Georgia	Bartow	713	1971	2010

Crist	641_B_6	Florida	Escambia	302	1970	2010
Crist	641_B_7	Florida	Escambia	477	1973	2010
Clifty Creek	983_B_1	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_2	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_3	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_4	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_5	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_6	Indiana	Jefferson	217	1956	2010
Chalk Point LLC	1571_B_1	Maryland	Prince George's	341	1964	2010
Chalk Point LLC	1571_B_2	Maryland	Prince George's	342	1965	2010
Dickerson	1572_B_1	Maryland	Montgomery	182	1959	2010
Dickerson	1572_B_2	Maryland	Montgomery	182	1960	2010
Dickerson	1572_B_3	Maryland	Montgomery	182	1962	2010
R E Burger	2864_B_7	Ohio	Belmont	156	1955	2010
R E Burger	2864_B_8	Ohio	Belmont	156	1955	2010
Kyger Creek	2876_B_1	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_2	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_3	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_4	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_5	Ohio	Gallia	217	1955	2010
Cheswick	8226_B_1	Pennsylvania	Allegheny	580	1970	2010
PSEG Mercer Generating Station	2408_B_1	New Jersey	Mercer	315	1960	2010
PSEG Mercer Generating Station	2408_B_2	New Jersey	Mercer	310	1961	2010
Silver Lake	2008_B_4	Minnesota	Olmsted	61	1969	2010
Kingston	3407_B_1	Tennessee	Roane	135	1954	2010
Kingston	3407_B_2	Tennessee	Roane	135	1954	2010
Kingston	3407_B_3	Tennessee	Roane	135	1954	2010
Kingston	3407_B_4	Tennessee	Roane	135	1954	2010
Kingston	3407_B_5	Tennessee	Roane	177	1955	2010
Kingston	3407_B_6	Tennessee	Roane	177	1955	2010
Kingston	3407_B_7	Tennessee	Roane	177	1955	2010
Kingston	3407_B_8	Tennessee	Roane	177	1955	2010
Kingston	3407_B_9	Tennessee	Roane	178	1955	2010
Sioux	2107_B_1	Missouri	St. Charles	497	1967	2010
Sioux	2107_B_2	Missouri	St. Charles	497	1968	2010
Chesterfield	3797_B_5	Virginia	Chesterfield	310	1964	2010
Yorktown	3809_B_1	Virginia	York	159	1957	2010
AES Westover	2526_B_11	New York	Broome	22	1943	2010
AES Westover	2526_B_12	New York	Broome	22	1943	2010
AES Westover	2526_B_13	New York	Broome	84	1951	2010
Iatan 2	6065_B_2	Missouri	Platte	850	2010	2010
Southwest	6195_B_2	Missouri	Greene	300	2010	2010
Trimble Station (LGE)	6071_B_2	Kentucky	Trimble	732	2010	2010
Elm Road Generating Station	56068_B_2	Wisconsin	Milwaukee	615	2010	2010
Cholla	113_B_3	Arizona	Navajo	271	1980	2009
Mayo	6250_B_1A	North Carolina	Person	362	1983	2009
Mayo	6250_B_1B	North Carolina	Person	362	1983	2009
Conesville	2840_B_4	Ohio	Coshocton	780	1973	2009
G G Allen	2718_B_1	North Carolina	Gaston	162	1957	2009
G G Allen	2718_B_2	North Carolina	Gaston	162	1957	2009
G G Allen	2718_B_3	North Carolina	Gaston	260	1959	2009

G G Allen	2718_B_4	North Carolina	Gaston	275	1960	2009
G G Allen	2718_B_5	North Carolina	Gaston	265	1961	2009
H L Spurlock	6041_B_1	Kentucky	Mason	315	1977	2009
Crystal River	628_B_5	Florida	Citrus	717	1984	2009
Deerhaven Generating Station	663_B_B2	Florida	Alachua	228	1981	2009
Bowen	703_B_2BLR	Georgia	Bartow	718	1972	2009
Wansley	6052_B_2	Georgia	Heard	892	1978	2009
E W Brown	1355_B_1	Kentucky	Mercer	94	1957	2009
E W Brown	1355_B_2	Kentucky	Mercer	160	1963	2009
E W Brown	1355_B_3	Kentucky	Mercer	422	1971	2009
Ghent	1356_B_2	Kentucky	Carroll	469	1977	2009
Fayette Power Project	6179_B_1	Texas	Fayette	598	1979	2009
Fayette Power Project	6179_B_2	Texas	Fayette	598	1980	2009
Morgantown Generating Plant	1573_B_1	Maryland	Charles	624	1970	2009
Morgantown Generating Plant	1573_B_2	Maryland	Charles	620	1971	2009
PPL Brunner Island	3140_B_1	Pennsylvania	York	321	1961	2009
PPL Brunner Island	3140_B_2	Pennsylvania	York	378	1965	2009
Keystone	3136_B_1	Pennsylvania	Armstrong	850	1967	2009
Keystone	3136_B_2	Pennsylvania	Armstrong	850	1968	2009
Bull Run	3396_B_1	Tennessee	Anderson	881	1967	2009
Bay Shore	2878_B_4	Ohio	Lucas	215	1968	2009
Hatfields Ferry Power Station	3179_B_1	Pennsylvania	Greene	530	1969	2009
Hatfields Ferry Power Station	3179_B_2	Pennsylvania	Greene	530	1970	2009
Hatfields Ferry Power Station	3179_B_3	Pennsylvania	Greene	530	1971	2009
Nebraska City Unit 2	6096_B_2	Nebraska	Otoe	663	2009	2009
Cross	130_B_4	South Carolina	Berkeley	652	2009	2009
Springerville	8223_B_4	Arizona	Apache	400	2009	2009
Sandow 5	82010_B_5	Texas	Milam	600	2009	2009
Oak Grove	82011_B_1	Texas	Robertson	800	2009	2009
Oak Grove	82011_B_2	Texas	Robertson	800	2009	2009
TS Power Plant	82013_B_1	Nevada	Eureka	200	2009	2009
Plum Point Energy	82014_B_1	Arkansas	Mississippi	665	2009	2009
Comanche	470_B_3	Colorado	Pueblo	750	2009	2009
Elm Road Generating Station	56068_B_1	Wisconsin	Milwaukee	615	2009	2009
Two Elk Generating Station	55360_B_1	Wyoming	Campbell	300	2009	2009
J K Spruce	7097_B_BLR2	Texas	Bexar	750	2009	2009
Dallman	963_B_34	Illinois	Sangamon	200	2009	2009
Charles R Lowman	56_B_1	Alabama	Washington	86	1969	2008
John E Amos	3935_B_1	West Virginia	Putnam	800	1971	2008
John E Amos	3935_B_2	West Virginia	Putnam	800	1972	2008
Cholla	113_B_4	Arizona	Navajo	380	1981	2008
Roxboro	2712_B_1	North Carolina	Person	369	1966	2008
Roxboro	2712_B_3A	North Carolina	Person	341	1973	2008
Roxboro	2712_B_3B	North Carolina	Person	341	1973	2008
Miami Fort	2832_B_7	Ohio	Hamilton	500	1975	2008
Miami Fort	2832_B_8	Ohio	Hamilton	500	1978	2008
Cogentrix Virginia Leasing Corp	10071_B_2A	Virginia	Portsmouth	19	1988	2008
Cogentrix Virginia Leasing Corp	10071_B_2B	Virginia	Portsmouth	19	1988	2008
Cogentrix Virginia Leasing Corp	10071_B_2C	Virginia	Portsmouth	19	1988	2008
J M Stuart	2850_B_1	Ohio	Adams	585	1971	2008
J M Stuart	2850_B_2	Ohio	Adams	597	1970	2008

J M Stuart	2850_B_3	Ohio	Adams	597	1972	2008
J M Stuart	2850_B_4	Ohio	Adams	597	1974	2008
Monroe	1733_B_3	Michigan	Monroe	795	1973	2008
Belews Creek	8042_B_1	North Carolina	Stokes	1,115	1974	2008
Belews Creek	8042_B_2	North Carolina	Stokes	1,115	1975	2008
Bowen	703_B_3BLR	Georgia	Bartow	902	1974	2008
Bowen	703_B_4BLR	Georgia	Bartow	929	1975	2008
Hammond	708_B_1	Georgia	Floyd	112	1954	2008
Hammond	708_B_2	Georgia	Floyd	112	1954	2008
Hammond	708_B_3	Georgia	Floyd	112	1955	2008
Hammond	708_B_4	Georgia	Floyd	510	1970	2008
Wansley	6052_B_1	Georgia	Heard	891	1976	2008
Harding Street	990_B_70	Indiana	Marion	435	1973	2008
Cogentrix Hopewell	10377_B_1A	Virginia	Hopewell (city)	18	1987	2008
Cogentrix Hopewell	10377_B_1B	Virginia	Hopewell (city)	18	1987	2008
Cogentrix Hopewell	10377_B_1C	Virginia	Hopewell (city)	18	1987	2008
Ghent	1356_B_4	Kentucky	Carroll	478	1984	2008
Council Bluffs	1082_B_3	Iowa	Pottawattamie	690	1978	2008
PPL Brunner Island	3140_B_3	Pennsylvania	York	749	1969	2008
PPL Montour	3149_B_1	Pennsylvania	Montour	774	1972	2008
PPL Montour	3149_B_2	Pennsylvania	Montour	766	1973	2008
Comanche	470_B_1	Colorado	Pueblo	366	1973	2008
Comanche	470_B_2	Colorado	Pueblo	370	1975	2008
Cayuga	1001_B_2	Indiana	Vermillon	473	1972	2008
Winyah	6249_B_1	South Carolina	Georgetown	295	1975	2008
Winyah	6249_B_2	South Carolina	Georgetown	295	1977	2008
Winyah	6249_B_3	South Carolina	Georgetown	295	1980	2008
Chesterfield	3797_B_6	Virginia	Chesterfield	658	1969	2008
Brayton Point	1619_B_1	Massachusetts	Bristo	243	1963	2008
Brayton Point	1619_B_2	Massachusetts	Bristo	244	1964	2008
Weston	4078_B_4	Wisconsin	Marathon	519	2008	2008
Gorgas	8_B_10	Alabama	Walker	690	1972	2007
Gorgas	8_B_8	Alabama	Walker	165	1956	2007
Gorgas	8_B_9	Alabama	Walker	175	1958	2007
John E Amos	3935_B_3	West Virginia	Putnam	1,300	1973	2007
Mountaineer	6264_B_1	West Virginia	Mason	1,300	1980	2007
Cardinal	2828_B_1	Ohio	Jefferson	600	1967	2007
Cardinal	2828_B_2	Ohio	Jefferson	600	1967	2007
Roxboro	2712_B_2	North Carolina	Person	639	1968	2007
Roxboro	2712_B_4A	North Carolina	Person	343	1980	2007
Roxboro	2712_B_4B	North Carolina	Person	343	1980	2007
Cogentrix Virginia Leasing Corp	10071_B_1A	Virginia	Portsmouth	19	1988	2007
Cogentrix Virginia Leasing Corp	10071_B_1B	Virginia	Portsmouth	19	1988	2007
Cogentrix Virginia Leasing Corp	10071_B_1C	Virginia	Portsmouth	19	1988	2007
Killen Station	6031_B_2	Ohio	Adams	615	1982	2007
Marshall	2727_B_2	North Carolina	Catawba	378	1966	2007
Marshall	2727_B_3	North Carolina	Catawba	657	1969	2007
Cogentrix Hopewell	10377_B_2A	Virginia	Hopewell (city)	18	1987	2007
Cogentrix Hopewell	10377_B_2B	Virginia	Hopewell (city)	18	1987	2007
Cogentrix Hopewell	10377_B_2C	Virginia	Hopewell (city)	18	1987	2007
Ghent	1356_B_3	Kentucky	Carroll	478	1981	2007

Louisa	6664_B_101	Iowa	Louisa	700	1983	2007
Allen S King	1915_B_1	Minnesota	Washington	571	1968	2007
Mitchell	3948_B_1	West Virginia	Marshall	800	1971	2007
Gibson	6113_B_1	Indiana	Gibson	630	1975	2007
Gibson	6113_B_2	Indiana	Gibson	628	1975	2007
Winyah	6249_B_4	South Carolina	Georgetown	270	1981	2007
Pleasant Prairie	6170_B_2	Wisconsin	Kenosha	617	1985	2007
Cross	130_B_3	South Carolina	Berkeley	620	2007	2007
Wygen II	55479_B_4	Wyoming	Campbell	90	2007	2007
Council Bluffs	1082_B_4	Iowa	Pottawattamie	790	2007	2007

Assumed BART Facilities and Units

State	County	Fac ID	Facility Name	Unit ID
MI	Bay	B2840	CE - KARN/WEADOCK	EU00036
MI	Bay	B2840	CE - KARN/WEADOCK	EU00037
MI	Eaton	B4001	LAN. BW&L ERICKSON	EU00007
MI	Houghton	B6553	UP POWER CO / PORTAGE	EU00008
MI	Huron	B2815	DTE - HARBOR BEACH	EU00009
MI	Ingham	B2647	LAN. BW&L Eckert	RG00023
MI	Ingham	B2647	LAN. BW&L Eckert	RG00023
MI	Ingham	B2647	LAN. BW&L Eckert	RG00023
MI	Ingham	B2647	LAN. BW&L Moores Park	RG00021
MI	Marquette	B4261	WE-ENERGIES	EU00029
MI	Marquette	B4261	WE-ENERGIES	EU00030
MI	Marquette	B4261	WE-ENERGIES	EU00031
MI	Marquette	B4261	WE-ENERGIES	EU00032
MI	Marquette	B4261	WE-ENERGIES	EU00033
MI	Monroe	B2816	DTE - MONROE	EU00062
MI	Monroe	B2816	DTE - MONROE	EU00068
MI	Monroe	B2816	DTE - MONROE	EU00063
MI	Monroe	B2816	DTE - MONROE	EU00064
MI	Ottawa	B2835	CE – CAMPBELL	EU00062
MI	Ottawa	B2835	CE – CAMPBELL	EU00061
MI	Saint Clair	B2796	DTE - ST. CLAIR / BELLE RIVER	EU00111
MI	Saint Clair	B6145	DTE – GREENWOOD	EU00009
MI	Wayne	B2132	WYANDOTTE	EU00036
MI	Wayne	B2185	DETROIT PLD, MISTERSKY	EU00014
MI	Wayne	B2811	DTE – TRENTON	EU00035
OH	Lake	0243160009	CEI., EASTLAKE PLANT	B005
OH		0247030013	Orion Power Midwest	B012
OH		0285010188	Dept of Public Utilities, City of Orrville	B001
OH		0285010188	Dept of Public Utilities, City of Orrville	B004
OH		0448020006	Toledo Edison Co., Bay Shore	B003
OH		0448020006	Toledo Edison Co., Bay Shore	B004
OH		0616000000	Conesville Power Plant	B003
OH		0616000000	Conesville Power Plant	B004
OH		0616000000	Conesville Power Plant	B007
OH		0641050002	Cardinal Power Plant	B001
OH		0641050002	Cardinal Power Plant	B002

OH		0641050002	Cardinal Power Plant	B003
OH		0641050002	Cardinal Power Plant	B004
OH		0641050002	Cardinal Power Plant	B008
OH		0641050002	Cardinal Power Plant	B009
OH		0641050002	Cardinal Power Plant	B009
OH	Jefferson	0641160017	W. H. SAMMIS PLANT	B011
OH	Jefferson	0641160017	W. H. SAMMIS PLANT	B012
OH	Jefferson	0641160017	W. H. SAMMIS PLANT	B013
OH		0684000000	Muskingum River Power Plant	B006
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B001
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B002
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B003
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B004
OH		0701000060	DP&L, Killen Station	B001
OH		1409040243	City of Hamilton Dept of Public Utilities	B002
OH		1409040243	City of Hamilton Dept of Public Utilities	B008
OH		1409040243	City of Hamilton Dept of Public Utilities	B009
OH		1413100008	CG&E W. C. BECKJORD	B005
OH		1413100008	CG&E W. C. BECKJORD	B006
OH		1431350093	CG&E MIAMI FORT STATION	B015
IL	Peoria	856	Ameren – Edwards	2
IL	Sangamon	963	CWLP – Dallman	31
IL	Sangamon	963	CWLP – Dallman	32
IL	Christian	876	Dominion – Kincaid	1
IL	Christian	876	Dominion – Kincaid	2
WI	COLUMBIA	111003090	Alliant Energy-Columbia Generating	B20
WI	COLUMBIA	111003090	Alliant Energy-Columbia Generating	B21
WI	COLUMBIA	111003090	Alliant Energy-Columbia Generating	B22
WI	GRANT	122014530	Alliant Energy, Nelson Dewey	B22 (unit 2)
WI	MILWAUKEE	241007690	We Energies-Oak Creek Station	B26 (Unit 6)
WI	MILWAUKEE	241007690	We Energies-Oak Creek Station	B27 (Unit 7)
WI	MILWAUKEE	241007690	We Energies-Oak Creek Station	B28
WI	MILWAUKEE	241007800	We Energies-Valley Station	B21
WI	MILWAUKEE	241007800	We Energies-Valley Station	B23
WI	MILWAUKEE	241007800	We Energies-Valley Station	B24
WI	BROWN	405031990	WI Public Service Corp - JP Pulliam	B27 (unit 8)
WI	SHEBOYGAN	460033090	WP & L Alliant Energy – Edgewater	B24
WI	BUFFALO	606034110	Dairyland Power Coop Alma Station (J.P. Madgett boilers)	B25 (+B26)
WI	BUFFALO	606034110	Dairyland Power Coop Alma Station	B27
WI	VERNON	663020930	Dairyland Power Coop Genoa Station	B20
WI	VERNON	663020930	Dairyland Power Coop Genoa Station	B25
IN	Porter	995	Bailly	7
IN	Porter	995	Bailly	8
IN	Vermillion	1001	Cayuga	1
IN	Vermillion	1001	Cayuga	2
IN	Montgomery	1024	Crawfordsville	6
IN	Warrick	1012	Culley	2

IN	Warrick	1012	Culley	3
IN	Gibson	6113	Gibson	1
IN	Gibson	6113	Gibson	2
IN	Cass	1032	Logansport	6
IN	Sullivan	6213	Merom	1
IN	Sullivan	6213	Merom	2
IN	LaPorte	997	Michigan City	12
IN	Lake	996	Mitchell	11
IN	Pike	994	Petersburg	1
IN	Pike	994	Petersburg	2
IN	Pike	994	Petersburg	3
IN	Pike	1043	Ratts	1
IN	Pike	1043	Ratts	2
IN	Wayne	7335	RPL	2
IN	Jasper	6085	Schahfer	14
IN	Jasper	6085	Schahfer	15
IN	Lake	981	Stateline	4
IN	Marion	990	Stout	70
IN	Dearborn	988	Tanners Creek	4
IN	Vigo	1010	Wabash River	6
IN	Warrick	6705	Warrick	4
IA		07-02-005	Cedar Falls Utilities	Unit #7 (EU10.1A)
IA		88-01-004	Central Iowa Power Cooperative (CIPCO) – Summit Lake Station	CombTurbines (EU 1/1G, EU2/2G)
IA		70-08-003	Central Iowa Power Cooperative (CIPCO) – Fair Station	Unit # 2 (EU 2 & EU 2G)
IA		85-01-006	City of Ames - Steam Electric Plant	Boiler #7 (EU 2)
IA		29-01-013	Interstate Power & Light - Burlington	Main Plant Boiler.
IA		03-03-001	Interstate Power & Light - Lansing	Boiler #4. Sixteen units in total.
IA		23-01-014	Interstate Power & Light - ML Kapp	Boiler #2. Six units in total.
IA		57-01-042	Interstate Power & Light - Prairie Creek	Boiler #4. Fourteen units in total.
IA		78-01-026	MidAmerican Energy Co - Council Bluffs	Boiler #3 (EU003)
IA		97-04-010	MidAmerican Energy Co - Neal North	Boilers #1-3 (EU001 - EU003)
IA		97-04-011	MidAmerican Energy Co - Neal South	Boiler #4 (EU003)
IA		70-01-011	Muscatine Power and Water	Boiler #8
IA		63-02-005	Pella Municipal Power Plant	Boilers #6-8
MN		2709900001	Austin Utilities NE Power Station	EU001
MN		2713700027	Hibbing Public Utilities	EU003
MN		2703100001	MN Power, Taconite Harbor	EU003
MN		2706100004	MN Power, Boswell Energy Center	EU003
MN		2701500010	New Ulm Public Utilities	EU003 - Boiler 4
MN		2711100002	Otter Tail Power Hoot Lake	EU003
MN		2710900011	Rochester Public Utilities, Silver Lake	EU003
MN		2710900011	Rochester Public Utilities, Silver Lake	EU004
MN		2713700028	Virginia Public Utilities	EU003 - Boiler 9
MN		2714100004	Xcel Energy, Sherco	EU001, EU002
MN		2716300005	Xcel Energy, Allen S King	EU001 - Boiler 1

MN		2705300015	Xcel Energy, Riverside	EU003 - Boiler 8
MO		290710003	Ameren -Labadie	B1, B2, B3, B4
MO		291830001	Ameren - Sioux	B1, B2
MO		290990016	Ameren - Rush Island	B1, B2
MO		290950031	Auila - Sibley	B3 - 5C
MO		291430004	Assoc. Electric - New Madrid	B1(EP-01), B2 (EP-02)
MO		290770039	City Utilities Springfield - Southwest	B1 (E09)
MO		290770005	City Utilities Springfield - James River	EO7, EO8
MO		290970001	Empire Distric Electric - Asbury	B7
MO		290830001	KC Power and Light - Montrose	EP08
MO		290210004	Aqula - Lake Road	EP06
MO		291750001	Assoc. Electric - Thomas Hill	EP01, EP02
MO		290950021	Trigen - Kansas City	B1A
MO		290190002	City of Columbia Municipal Power Plant	EP02
MO		291950010	Marshall Munipal Utilities	EP05
MO		290950050	Independence Power & Light-Blue Valley	B3 (EP05)
WV		3943	Fort Martin	
WV		6004	Pleasants	
WV		3948	Mitchell	
WV		3935	Amos	
WV		6264	Mountaineer	
WV		3944	Harrison	
TN		3396	TVA Bull Run	
TN		3399	TVA Cumberland	
KY		1363	Cane Run	
KY		1364	Mill Creek	
KY		6041	Spurlock	
KY		1384	John Sherman Cooper	
KY		1353	Big Sandy	
KY		1356	Ghent	
KY		1355	Brown	
KY		1374	Owensboro Municipal	
KY		1372	Henderson Municipal	
KY		1378	Paradise	
KY		1361	Coleman	
KY		1382	Reid/Henderson 2	
KY		6639	Green	

Appendix E

Mobile Inventory

Technical Support Document for

Ohio, Kentucky, Indiana Regional Council of Governments (OKI)

Mobile Source Emissions Inventory for Cincinnati PM2.5 Nonattainment Area

Includes a portion of Dearborn County, Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. Emission estimates for the Year 2005, 2008, 2011, 2015, 2018, and 2021 developed in support of the PM2.5 State Implementation Plan

August 2010 (text revised Dec 2010)

Prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency by

OKI Regional Council of Governments

OKI
Ohio · Kentucky · Indiana
Regional Council of Governments

Acknowledgments

Title	Mobile Source Emissions Inventory for Cincinnati PM2.5 Nonattainment Area
Abstract	This report was prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency. The Cincinnati PM2.5 nonattainment area includes a portion of Dearborn County Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. This report includes emission estimates for the years 2005, 2008, 2011, 2015, 2018 and 2021 was generated to support the attainment SIPs for the annual PM2.5 standard. EPA's Motor Vehicle Emission Simulation (MOVES) 2010 was used to generate the emission rates.
Date	August 2010
Agency	Ohio-Kentucky-Indiana Regional Council of Governments Mark Policinski, Executive Director Robert Koehler, P.E., Deputy Director
Project Manager	Andrew J. Reser, AICP
Project Staff	Harikishan Perugu, PTP Larry Buckler

The preparation of this document was financed cooperatively by the Federal Highway Administration, the Federal Transit Administration, the Commonwealth of Kentucky Transportation Cabinet, the Ohio Department of Transportation, and the units of local and county government in the OKI region. The opinions, findings, and conclusions expressed in this document are those of the OKI Regional Council of Governments and are not necessarily those of the U.S. Department of Transportation. This report does not constitute a standard, specification, or regulation.

MOBILE Source Emissions Inventory for the Cincinnati PM2.5 nonattainment area

This report was prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency. The Cincinnati PM2.5 nonattainment area includes a portion of Dearborn County Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. This report includes emission estimates for the years 2005, 2008, 2011, 2015, 2018 and 2021 was generated to support the attainment SIPs for the annual PM2.5 standard. EPA's Motor Vehicle Emissions Simulator (MOVES) 2010 model was used to generate the vehicle emission rates. In December 2009, MOVES replaced MOBILE6.2 as the EPA's official emission factor model. Technical details on OKI's use of MOVES can be found in the Appendix. The OKI travel demand model version 7.6 was used to generate VMT and speed estimates. MOVES emission rates were generated for direct PM2.5, PM2.5 tirewear, PM2.5 brakewear, NO_x and SO_2.

OKI, as the MPO, is responsible for transportation planning and air quality/transportation conformity. Transportation conformity is a mechanism to ensure that federal funding and approval are given to those transportation activities that are consistent with the air quality goals of the State Implementation Plans (SIPs) for Indiana, Kentucky and Ohio. The SIPs include an inventory of projected emissions from vehicles. One or more of the analysis years in the projected inventory may be designated as the motor vehicle emissions budget (MVEB). This budget establishes a maximum allowable limit on future emissions from vehicles (mobile sources). OKI's transportation plans and programs must be shown to be in conformity with all SIP provisions. The conformity process is a quantitative analysis, using U.S.EPA's vehicle emissions software (currently MOVES), demonstrating that forecasted regional vehicle emissions do not exceed the established budget.

Table 1 shows daily and annual mobile source emissions for the combined Indiana and Ohio portions of the nonattainment area, as well as the Kentucky portion of the nonattainment area. Separate MVEB's are typically designated for these two areas. Although official federal guidance on the use of MOVES for PM2.5 SIP development was not available at the time of this analysis, the Federal Highway Administration (FHWA) along with state and local air quality staff were consulted periodically throughout the development of these emissions. An additional safety margin should be added to the MVEB's due uncertainty with growth assumptions utilized in the OKI travel demand model and uncertainty regarding the use of MOVES. Daily and annual mobile source emissions for each county in the nonattainment area are shown in Table 2.

Table 1. Mobile Source Emissions for the Cincinnati PM2.5 Nonattainment Area (tons)

Kentucky Portion of NA Area

2005 Vehicle Population: 364,081 Daily VMT: 9,621,110 Annual VMT: 3,289,109,202

Year	Pollutant Name	DailyEmissions	AnnualEmissions
2005	Oxides of Nitrogen	39.10	13,496.54
2005	Primary Exhaust PM2.5 - Total	1.36	466.23
2005	Primary PM2.5 - Brakewear Particulate	0.16	54.04
2005	Primary PM2.5 - Tirewear Particulate	0.05	17.52
2005	Sulfur Dioxide (SO2)	0.12	41.46

2008 Vehicle Population: 375,873 Daily VMT: 9,991,179 Annual VMT: 3,425,339,505

Year	Pollutant Name	DailyEmissions	AnnualEmissions
2008	Oxides of Nitrogen	37.91	13,114.20
2008	Primary Exhaust PM2.5 - Total	1.64	562.84
2008	Primary PM2.5 - Brakewear Particulate	0.18	62.10
2008	Primary PM2.5 - Tirewear Particulate	0.06	20.70
2008	Sulfur Dioxide (SO2)	0.12	42.74

2011 Vehicle Population: 381,911 Daily VMT: 10,490,143 Annual VMT: 3,587,796,186

Year	Pollutant Name	DailyEmissions	AnnualEmissions
2011	Oxides of Nitrogen	29.33	10,141.52
2011	Primary Exhaust PM2.5 - Total	1.19	407.74
2011	Primary PM2.5 - Brakewear Particulate	0.20	68.38
2011	Primary PM2.5 - Tirewear Particulate	0.07	22.68
2011	Sulfur Dioxide (SO2)	0.13	45.36

2015 Vehicle Population: 394,278 Daily VMT: 11,495,496 Annual VMT: 3,931,385,741

Year	Pollutant Name	DailyEmissions	AnnualEmissions
2015	Oxides of Nitrogen	20.18	6,996.21
2015	Primary Exhaust PM2.5 - Total	0.78	267.30
2015	Primary PM2.5 - Brakewear Particulate	0.23	77.94
2015	Primary PM2.5 - Tirewear Particulate	0.08	25.88
2015	Sulfur Dioxide (SO2)	0.15	50.50

2018 Vehicle Population: 403,817 Daily VMT: 12,173,549 Annual VMT: 4,163,203,435

Year	Pollutant Name	DailyEmissions	AnnualEmissions
2018	Oxides of Nitrogen	15.78	5,480.81
2018	Primary Exhaust PM2.5 - Total	0.59	202.15
2018	Primary PM2.5 - Brakewear Particulate	0.27	91.15
2018	Primary PM2.5 - Tirewear Particulate	0.09	30.09
2018	Sulfur Dioxide (SO2)	0.16	56.28

2021 Vehicle Population: 413,587 Daily VMT: 12,534,236 Annual VMT: 4,286,834,360

Year	Pollutant Name	DailyEmissions	AnnualEmissions
2021	Oxides of Nitrogen	12.75	4,435.96
2021	Primary Exhaust PM2.5 - Total	0.43	146.79
2021	Primary PM2.5 - Brakewear Particulate	0.28	96.84
2021	Primary PM2.5 - Tirewear Particulate	0.09	31.74
2021	Sulfur Dioxide (SO2)	0.17	58.63

Year	Pollutant Name	DailyEmissions	AnnualEmissions

Ohio/Indiana Portion of NA Area

2005 Vehicle Population: 1,754,582 Daily VMT: 39,564,030 Annual VMT: 13,541,324,003

Oxides of Nitrogen	168.89	58,423.36
Primary Exhaust PM2.5 - Total	5.74	1,979.63
Primary PM2.5 - Brakewear Particulate	0.65	223.20
Primary PM2.5 - Tirewear Particulate	0.20	69.67
Sulfur Dioxide (SO2)	0.48	165.35

2008 Vehicle Population: 1,811,406 Daily VMT: 40,858,751 Annual VMT: 14,015,754,874

Oxides of Nitrogen	148.02	51,357.02
Primary Exhaust PM2.5 - Total	4.85	1,675.04
Primary PM2.5 - Brakewear Particulate	0.80	273.84
Primary PM2.5 - Tirewear Particulate	0.25	85.37
Sulfur Dioxide (SO2)	0.54	185.13

2011 Vehicle Population: 1,840,505 Daily VMT: 42,044,841 Annual VMT: 14,383,526,419

Oxides of Nitrogen	135.95	47,061.53
Primary Exhaust PM2.5 - Total	5.54	1,904.61
Primary PM2.5 - Brakewear Particulate	0.85	290.00
Primary PM2.5 - Tirewear Particulate	0.27	91.52
Sulfur Dioxide (SO2)	0.53	182.01

2015 Vehicle Population: 1,900,111 Daily VMT: 43,316,281 Annual VMT: 14,830,453,053

Oxides of Nitrogen	89.45	31,064.21
Primary Exhaust PM2.5 - Total	3.57	1,227.86
Primary PM2.5 - Brakewear Particulate	0.82	280.25
Primary PM2.5 - Tirewear Particulate	0.26	90.54
Sulfur Dioxide (SO2)	0.53	182.69

2018 Vehicle Population: 1,946,080 Daily VMT: 45,314,292 Annual VMT: 15,513,701,656

Oxides of Nitrogen	70.34	24,451.43
Primary Exhaust PM2.5 - Total	2.78	958.57
Primary PM2.5 - Brakewear Particulate	0.90	307.39
Primary PM2.5 - Tirewear Particulate	0.29	99.03
Sulfur Dioxide (SO2)	0.57	195.09

2021 Vehicle Population: 1,993,161 Daily VMT: 46,689,707 Annual VMT: 15,521,916,278

Oxides of Nitrogen	55.50	18,911.05
Primary Exhaust PM2.5 - Total	2.10	705.30
Primary PM2.5 - Brakewear Particulate	0.96	320.17
Primary PM2.5 - Tirewear Particulate	0.31	102.89
Sulfur Dioxide (SO2)	0.60	199.14

Table 2. Mobile Source Emissions by County for the Cincinnati PM2.5 Nonattainment Area (tons)

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Indiana

Dearborn NA

2005 Vehicle Population: 24,915 Daily VMT: 578,642 Annual VMT: 196,738,031

Oxides of Nitrogen	2.40	865.46
Primary Exhaust PM2.5 - Total	0.08	29.68
Primary PM2.5 - Brakewear Particulate	0.01	3.28
Primary PM2.5 - Tirewear Particulate	0.00	1.02
Sulfur Dioxide (SO2)	0.01	2.45

2008 Vehicle Population: 25,722 Daily VMT: 587,583 Annual VMT: 199,778,078

Oxides of Nitrogen	2.09	748.81
Primary Exhaust PM2.5 - Total	0.07	24.72
Primary PM2.5 - Brakewear Particulate	0.01	3.94
Primary PM2.5 - Tirewear Particulate	0.00	1.23
Sulfur Dioxide (SO2)	0.01	2.69

2011 Vehicle Population: 26,135 Daily VMT: 605,621 Annual VMT: 205,911,005

Oxides of Nitrogen	1.92	685.40
Primary Exhaust PM2.5 - Total	0.08	27.88
Primary PM2.5 - Brakewear Particulate	0.01	4.19
Primary PM2.5 - Tirewear Particulate	0.00	1.32
Sulfur Dioxide (SO2)	0.01	2.65

2015 Vehicle Population: 26,982 Daily VMT: 657,779 Annual VMT: 223,644,622

Oxides of Nitrogen	1.31	482.33
Primary Exhaust PM2.5 - Total	0.05	19.43
Primary PM2.5 - Brakewear Particulate	0.01	4.32
Primary PM2.5 - Tirewear Particulate	0.00	1.39
Sulfur Dioxide (SO2)	0.01	2.87

2018 Vehicle Population: 27,635 Daily VMT: 684,362 Annual VMT: 232,682,971

Oxides of Nitrogen	1.03	376.85
Primary Exhaust PM2.5 - Total	0.04	15.09
Primary PM2.5 - Brakewear Particulate	0.01	4.70
Primary PM2.5 - Tirewear Particulate	0.00	1.51
Sulfur Dioxide (SO2)	0.01	3.04

2021 Vehicle Population: 28,303 Daily VMT: 706,829 Annual VMT: 240,321,759

Oxides of Nitrogen	0.81	297.95
Primary Exhaust PM2.5 - Total	0.03	11.44
Primary PM2.5 - Brakewear Particulate	0.01	5.05
Primary PM2.5 - Tirewear Particulate	0.00	1.62
Sulfur Dioxide (SO2)	0.01	3.19

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Kentucky

Boone

2005 Vehicle Population: 129,823 Daily VMT: 3,924,117 Annual VMT: 1,273,226,967

Oxides of Nitrogen	14.94	5,126.88
Primary Exhaust PM2.5 - Total	0.52	177.58
Primary PM2.5 - Brakewear Particulate	0.06	20.86
Primary PM2.5 - Tirewear Particulate	0.02	6.77
Sulfur Dioxide (SO2)	0.05	15.91

2008 Vehicle Population: 134,028 Daily VMT: 4,076,584 Annual VMT: 1,350,001,539

Oxides of Nitrogen	14.73	5,067.94
Primary Exhaust PM2.5 - Total	0.64	219.29
Primary PM2.5 - Brakewear Particulate	0.07	24.42
Primary PM2.5 - Tirewear Particulate	0.02	8.14
Sulfur Dioxide (SO2)	0.05	16.71

2011 Vehicle Population: 136,181 Daily VMT: 4,383,716 Annual VMT: 1,448,879,491

Oxides of Nitrogen	11.61	3,990.01
Primary Exhaust PM2.5 - Total	0.48	162.47
Primary PM2.5 - Brakewear Particulate	0.08	27.55
Primary PM2.5 - Tirewear Particulate	0.03	9.14
Sulfur Dioxide (SO2)	0.05	18.16

2015 Vehicle Population: 140,590 Daily VMT: 4,950,741 Annual VMT: 1,628,041,282

Oxides of Nitrogen	8.11	2,788.45
Primary Exhaust PM2.5 - Total	0.32	108.49
Primary PM2.5 - Brakewear Particulate	0.09	32.17
Primary PM2.5 - Tirewear Particulate	0.03	10.69
Sulfur Dioxide (SO2)	0.06	20.67

2018 Vehicle Population: 143,991 Daily VMT: 5,260,102 Annual VMT: 1,729,595,156

Oxides of Nitrogen	6.34	2,182.28
Primary Exhaust PM2.5 - Total	0.24	82.19
Primary PM2.5 - Brakewear Particulate	0.11	37.76
Primary PM2.5 - Tirewear Particulate	0.04	12.47
Sulfur Dioxide (SO2)	0.07	23.14

2021 Vehicle Population: 147,476 Daily VMT: 5,478,224 Annual VMT: 1,800,571,684

Oxides of Nitrogen	5.14	1,772.72
Primary Exhaust PM2.5 - Total	0.18	60.19
Primary PM2.5 - Brakewear Particulate	0.12	40.56
Primary PM2.5 - Tirewear Particulate	0.04	13.30
Sulfur Dioxide (SO2)	0.07	24.37

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Campbell				
	2005	Vehicle Population: 86,065	Daily VMT: 2,286,217	Annual VMT: 741,790,595
		Oxides of Nitrogen	8.87	3,041.21
		Primary Exhaust PM2.5 - Total	0.31	104.22
		Primary PM2.5 - Brakewear Particulate	0.04	12.14
		Primary PM2.5 - Tirewear Particulate	0.01	3.94
		Sulfur Dioxide (SO2)	0.03	9.30
	2008	Vehicle Population: 88,853	Daily VMT: 2,339,542	Annual VMT: 774,762,718
		Oxides of Nitrogen	8.63	2,988.33
		Primary Exhaust PM2.5 - Total	0.37	127.73
		Primary PM2.5 - Brakewear Particulate	0.04	14.05
		Primary PM2.5 - Tirewear Particulate	0.01	4.68
		Sulfur Dioxide (SO2)	0.03	9.69
	2011	Vehicle Population: 90,279	Daily VMT: 2,421,600	Annual VMT: 800,372,692
		Oxides of Nitrogen	6.61	2,287.81
		Primary Exhaust PM2.5 - Total	0.27	91.36
		Primary PM2.5 - Brakewear Particulate	0.04	15.26
		Primary PM2.5 - Tirewear Particulate	0.01	5.06
		Sulfur Dioxide (SO2)	0.03	10.15
	2015	Vehicle Population: 93,204	Daily VMT: 2,663,159	Annual VMT: 875,774,487
		Oxides of Nitrogen	4.55	1,570.14
		Primary Exhaust PM2.5 - Total	0.17	59.30
		Primary PM2.5 - Brakewear Particulate	0.05	17.31
		Primary PM2.5 - Tirewear Particulate	0.02	5.75
		Sulfur Dioxide (SO2)	0.03	11.21
	2018	Vehicle Population: 95,458	Daily VMT: 2,771,476	Annual VMT: 911,300,097
		Oxides of Nitrogen	3.52	1,216.21
		Primary Exhaust PM2.5 - Total	0.13	44.14
		Primary PM2.5 - Brakewear Particulate	0.06	19.90
		Primary PM2.5 - Tirewear Particulate	0.02	6.57
		Sulfur Dioxide (SO2)	0.04	12.28
	2021	Vehicle Population: 97,768	Daily VMT: 2,849,127	Annual VMT: 936,445,352
		Oxides of Nitrogen	2.84	985.28
		Primary Exhaust PM2.5 - Total	0.09	32.07
		Primary PM2.5 - Brakewear Particulate	0.06	21.10
		Primary PM2.5 - Tirewear Particulate	0.02	6.92
		Sulfur Dioxide (SO2)	0.04	12.77

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Kenton

2005 Vehicle Population: 148,193 Daily VMT: 3,927,743 Annual VMT: 1,274,091,641

Oxides of Nitrogen	15.29	5,328.44
Primary Exhaust PM2.5 - Total	0.53	184.43
Primary PM2.5 - Brakewear Particulate	0.06	21.04
Primary PM2.5 - Tirewear Particulate	0.02	6.82
Sulfur Dioxide (SO2)	0.05	16.24

2008 Vehicle Population: 152,992 Daily VMT: 3,927,332 Annual VMT: 1,300,575,248

Oxides of Nitrogen	14.55	5,057.93
Primary Exhaust PM2.5 - Total	0.62	215.81
Primary PM2.5 - Brakewear Particulate	0.07	23.63
Primary PM2.5 - Tirewear Particulate	0.02	7.87
Sulfur Dioxide (SO2)	0.05	16.34

2011 Vehicle Population: 155,451 Daily VMT: 4,049,886 Annual VMT: 1,338,544,003

Oxides of Nitrogen	11.11	3,863.70
Primary Exhaust PM2.5 - Total	0.45	153.90
Primary PM2.5 - Brakewear Particulate	0.07	25.57
Primary PM2.5 - Tirewear Particulate	0.02	8.48
Sulfur Dioxide (SO2)	0.05	17.05

2015 Vehicle Population: 160,484 Daily VMT: 4,341,124 Annual VMT: 1,427,569,972

Oxides of Nitrogen	7.51	2,637.63
Primary Exhaust PM2.5 - Total	0.29	99.51
Primary PM2.5 - Brakewear Particulate	0.08	28.45
Primary PM2.5 - Tirewear Particulate	0.03	9.44
Sulfur Dioxide (SO2)	0.05	18.62

2018 Vehicle Population: 164,368 Daily VMT: 4,629,694 Annual VMT: 1,522,308,182

Oxides of Nitrogen	5.93	2,082.32
Primary Exhaust PM2.5 - Total	0.22	75.82
Primary PM2.5 - Brakewear Particulate	0.10	33.49
Primary PM2.5 - Tirewear Particulate	0.03	11.04
Sulfur Dioxide (SO2)	0.06	20.86

2021 Vehicle Population: 168,343 Daily VMT: 4,715,306 Annual VMT: 1,549,817,325

Oxides of Nitrogen	4.76	1,677.96
Primary Exhaust PM2.5 - Total	0.16	54.53
Primary PM2.5 - Brakewear Particulate	0.10	35.19
Primary PM2.5 - Tirewear Particulate	0.03	11.52
Sulfur Dioxide (SO2)	0.06	21.48

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Ohio

Butler

2005 Vehicle Population: 401,759 Daily VMT: 7,452,293 Annual VMT: 2,469,168,490

Oxides of Nitrogen	32.00	10,910.37
Primary Exhaust PM2.5 - Total	1.06	361.06
Primary PM2.5 - Brakewear Particulate	0.12	40.31
Primary PM2.5 - Tirewear Particulate	0.04	12.60
Sulfur Dioxide (SO2)	0.09	30.01

2008 Vehicle Population: 414,771 Daily VMT: 7,745,693 Annual VMT: 2,598,061,793

Oxides of Nitrogen	28.56	9,803.70
Primary Exhaust PM2.5 - Total	0.91	311.45
Primary PM2.5 - Brakewear Particulate	0.15	50.45
Primary PM2.5 - Tirewear Particulate	0.05	15.74
Sulfur Dioxide (SO2)	0.10	34.25

2011 Vehicle Population: 421,434 Daily VMT: 8,050,709 Annual VMT: 2,693,718,927

Oxides of Nitrogen	26.50	9,074.89
Primary Exhaust PM2.5 - Total	1.05	356.91
Primary PM2.5 - Brakewear Particulate	0.16	53.99
Primary PM2.5 - Tirewear Particulate	0.05	17.06
Sulfur Dioxide (SO2)	0.10	34.00

2015 Vehicle Population: 435,082 Daily VMT: 8,361,495 Annual VMT: 2,792,190,918

Oxides of Nitrogen	17.64	6,064.61
Primary Exhaust PM2.5 - Total	0.68	231.78
Primary PM2.5 - Brakewear Particulate	0.16	52.42
Primary PM2.5 - Tirewear Particulate	0.05	16.96
Sulfur Dioxide (SO2)	0.10	34.28

2018 Vehicle Population: 445,608 Daily VMT: 8,806,051 Annual VMT: 2,940,852,857

Oxides of Nitrogen	13.98	4,813.27
Primary Exhaust PM2.5 - Total	0.54	182.29
Primary PM2.5 - Brakewear Particulate	0.17	57.91
Primary PM2.5 - Tirewear Particulate	0.06	18.68
Sulfur Dioxide (SO2)	0.11	36.85

2021 Vehicle Population: 456,389 Daily VMT: 9,150,040 Annual VMT: 2,966,040,396

Oxides of Nitrogen	11.13	3,757.91
Primary Exhaust PM2.5 - Total	0.41	135.39
Primary PM2.5 - Brakewear Particulate	0.19	60.81
Primary PM2.5 - Tirewear Particulate	0.06	19.56
Sulfur Dioxide (SO2)	0.12	37.90

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Clermont

2005 Vehicle Population: 232,380 Daily VMT: 5,083,336 Annual VMT: 1,684,261,582

Oxides of Nitrogen	21.21	7,295.87
Primary Exhaust PM2.5 - Total	0.72	245.48
Primary PM2.5 - Brakewear Particulate	0.08	27.67
Primary PM2.5 - Tirewear Particulate	0.03	8.64
Sulfur Dioxide (SO2)	0.06	20.51

2008 Vehicle Population: 239,906 Daily VMT: 5,262,494 Annual VMT: 1,765,146,867

Oxides of Nitrogen	18.81	6,516.40
Primary Exhaust PM2.5 - Total	0.61	211.40
Primary PM2.5 - Brakewear Particulate	0.10	34.46
Primary PM2.5 - Tirewear Particulate	0.03	10.74
Sulfur Dioxide (SO2)	0.07	23.32

2011 Vehicle Population: 243,760 Daily VMT: 5,489,550 Annual VMT: 1,836,770,645

Oxides of Nitrogen	17.48	6,039.51
Primary Exhaust PM2.5 - Total	0.71	243.25
Primary PM2.5 - Brakewear Particulate	0.11	37.00
Primary PM2.5 - Tirewear Particulate	0.03	11.68
Sulfur Dioxide (SO2)	0.07	23.23

2015 Vehicle Population: 251,654 Daily VMT: 5,687,704 Annual VMT: 1,899,319,930

Oxides of Nitrogen	11.54	3,993.63
Primary Exhaust PM2.5 - Total	0.46	156.92
Primary PM2.5 - Brakewear Particulate	0.11	35.82
Primary PM2.5 - Tirewear Particulate	0.03	11.58
Sulfur Dioxide (SO2)	0.07	23.34

2018 Vehicle Population: 257,742 Daily VMT: 5,952,609 Annual VMT: 1,987,922,558

Oxides of Nitrogen	9.09	3,146.47
Primary Exhaust PM2.5 - Total	0.36	122.57
Primary PM2.5 - Brakewear Particulate	0.12	39.31
Primary PM2.5 - Tirewear Particulate	0.04	12.67
Sulfur Dioxide (SO2)	0.07	24.94

2021 Vehicle Population: 263,978 Daily VMT: 6,186,447 Annual VMT: 2,005,373,961

Oxides of Nitrogen	7.22	2,449.31
Primary Exhaust PM2.5 - Total	0.27	90.84
Primary PM2.5 - Brakewear Particulate	0.12	41.28
Primary PM2.5 - Tirewear Particulate	0.04	13.27
Sulfur Dioxide (SO2)	0.08	25.66

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Hamilton				

2005 Vehicle Population: 862,422 Daily VMT: 21,859,473 Annual VMT: 7,241,536,812

Oxides of Nitrogen	89.30	31,127.09
Primary Exhaust PM2.5 - Total	3.06	1,064.67
Primary PM2.5 - Brakewear Particulate	0.35	119.94
Primary PM2.5 - Tirewear Particulate	0.11	37.41
Sulfur Dioxide (SO2)	0.26	88.85

2008 Vehicle Population: 890,352 Daily VMT: 22,124,524 Annual VMT: 7,421,012,594

Oxides of Nitrogen	77.45	27,020.93
Primary Exhaust PM2.5 - Total	2.56	889.81
Primary PM2.5 - Brakewear Particulate	0.42	145.42
Primary PM2.5 - Tirewear Particulate	0.13	45.31
Sulfur Dioxide (SO2)	0.28	98.30

2011 Vehicle Population: 904,655 Daily VMT: 22,426,043 Annual VMT: 7,503,619,525

Oxides of Nitrogen	70.18	24,435.59
Primary Exhaust PM2.5 - Total	2.88	997.06
Primary PM2.5 - Brakewear Particulate	0.44	151.73
Primary PM2.5 - Tirewear Particulate	0.14	47.86
Sulfur Dioxide (SO2)	0.28	95.30

2015 Vehicle Population: 933,953 Daily VMT: 22,849,516 Annual VMT: 7,630,239,650

Oxides of Nitrogen	45.58	15,925.19
Primary Exhaust PM2.5 - Total	1.83	634.62
Primary PM2.5 - Brakewear Particulate	0.42	144.67
Primary PM2.5 - Tirewear Particulate	0.14	46.71
Sulfur Dioxide (SO2)	0.27	94.43

2018 Vehicle Population: 956,548 Daily VMT: 23,630,577 Annual VMT: 7,891,625,119

Oxides of Nitrogen	35.51	12,422.37
Primary Exhaust PM2.5 - Total	1.41	490.62
Primary PM2.5 - Brakewear Particulate	0.45	156.90
Primary PM2.5 - Tirewear Particulate	0.15	50.52
Sulfur Dioxide (SO2)	0.29	99.78

2021 Vehicle Population: 979,689 Daily VMT: 24,098,721 Annual VMT: 7,811,745,310

Oxides of Nitrogen	27.80	9,530.16
Primary Exhaust PM2.5 - Total	1.06	357.87
Primary PM2.5 - Brakewear Particulate	0.48	161.69
Primary PM2.5 - Tirewear Particulate	0.15	51.92
Sulfur Dioxide (SO2)	0.30	100.82

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Warren

2005 Vehicle Population: 233,106 Daily VMT: 5,884,222 Annual VMT: 1,949,619,088

Oxides of Nitrogen	23.98	8,224.57
Primary Exhaust PM2.5 - Total	0.82	278.74
Primary PM2.5 - Brakewear Particulate	0.09	32.00
Primary PM2.5 - Tirewear Particulate	0.03	10.00
Sulfur Dioxide (SO2)	0.07	23.54

2008 Vehicle Population: 240,655 Daily VMT: 6,057,344 Annual VMT: 2,031,755,542

Oxides of Nitrogen	21.11	7,267.18
Primary Exhaust PM2.5 - Total	0.69	237.65
Primary PM2.5 - Brakewear Particulate	0.12	39.57
Primary PM2.5 - Tirewear Particulate	0.04	12.34
Sulfur Dioxide (SO2)	0.08	26.57

2011 Vehicle Population: 244,521 Daily VMT: 6,406,290 Annual VMT: 2,143,506,318

Oxides of Nitrogen	19.88	6,826.15
Primary Exhaust PM2.5 - Total	0.82	279.53
Primary PM2.5 - Brakewear Particulate	0.13	43.09
Primary PM2.5 - Tirewear Particulate	0.04	13.60
Sulfur Dioxide (SO2)	0.08	26.83

2015 Vehicle Population: 252,440 Daily VMT: 6,842,835 Annual VMT: 2,285,057,933

Oxides of Nitrogen	13.37	4,598.44
Primary Exhaust PM2.5 - Total	0.54	185.12
Primary PM2.5 - Brakewear Particulate	0.13	43.02
Primary PM2.5 - Tirewear Particulate	0.04	13.91
Sulfur Dioxide (SO2)	0.08	27.77

2018 Vehicle Population: 258,547 Daily VMT: 7,368,042 Annual VMT: 2,460,618,151

Oxides of Nitrogen	10.73	3,692.47
Primary Exhaust PM2.5 - Total	0.43	148.00
Primary PM2.5 - Brakewear Particulate	0.14	48.57
Primary PM2.5 - Tirewear Particulate	0.05	15.66
Sulfur Dioxide (SO2)	0.09	30.49

2021 Vehicle Population: 264,802 Daily VMT: 7,707,508 Annual VMT: 2,498,434,852

Oxides of Nitrogen	8.54	2,875.72
Primary Exhaust PM2.5 - Total	0.33	109.76
Primary PM2.5 - Brakewear Particulate	0.16	51.34
Primary PM2.5 - Tirewear Particulate	0.05	16.51
Sulfur Dioxide (SO2)	0.10	31.58

Mobile Source Emission Forecast Process

Emission Factor Model

OKI's conformity assessment utilized U.S.EPA's emissions model MOVES 2010 to develop emission factors for SO_2, NO_X and PM2.5. Table 3 summarizes the settings used in the MOVES run specification file. Table 4 lists the data used in the MOVES County-Data Manager. Further details on the use of MOVES are found in the Appendix.

Table 3

MOVES RunSpec Parameter	Settings
MOVES Version 2009/05/15, MOVES default database 20100515	
Scale	County, Emission Rates
Time Span	Time aggregation = Hour 1 month representing average annual temperatures All hours of day selected Weekdays only
Geographic Bounds	2 Custom Domains – 4 Ohio counties, 3 Kentucky counties
Vehicles/Equipment	All source types, gasoline and diesel
Road Type	All road types including off-network
Pollutants and Processes	NO_x, All PM2.5 categories, SO_2, Total Energy Consumption
Strategies	Modified AVFT strategy file to reflect 0% CNG buses in the transit fleet
General Output	Units= grams, joules and miles
Output Emissions	Time = hour, Location =county, on-road emission rates by road type and source use type.
Advanced Performance	none

Table 4

County Data Manager	Data Source
Source Type Population	Local and default. Local data (2010) from KYTC and ODOT from motor vehicle registration data. Default data used for source types 41, 61 and 62. In addition , default data for source types 31, 32 and 54 used for KY.
Vehicle Type VMT	Local and default. HPMSVTypeYear VMT=daily VMT from OKI travel demand model with EPA's daily to annual VMT converter applied. monthVMTFraction = default. dayVMTFraction=default, hourVMTFraction=local.
I/M Programs	Default modified to reflect discontinued I/M program

Fuel Formulation	Default
Fuel Supply	Default
Meteorology Data	Local. Kentucky Division for Air Quality.
Ramp Fraction	Local. Ramp emissions calculated outside of MOVES
Road Type Distribution	Local. OKI travel demand model.
Age Distribution	Local and default. Local data (2010) from KYTC and ODOT from motor vehicle registration data. Default data used for source types 41, 61 and 62. In addition , default data for source types 31, 32 and 54 used for KY.
Average Speed Distribution	Local. OKI travel demand model.

OKI Travel Demand Model

Transportation system performance was estimated using the OKI Travel Demand Model Version 7.6. The OKI Travel Demand Model is composed of TRANPLAN programs, CUBE Voyager programs and a series of FORTRAN programs written by OKI. It is a state of the practice model that uses the standard 4 phase sequential modeling approach of trip generation, distribution, modal choice and assignment. The model uses demographic and land use data and capacity and free-flow speed characteristics for each roadway segment in the network to produce a "loaded" highway network with forecasted traffic volumes with revised speeds based on specified speed/capacity relationships.

Travel analysis zones are the basic geographic unit for estimating travel in the OKI model. The OKI region is subdivided into 1608 traffic analysis zones to permit detail as well as manageability. A variety of socioeconomic data items are used in the OKI transportation planning process. These data are used primarily to forecast future travel patterns by serving as independent variables in OKI trip generation equations. The following categories of planning data are utilized:

- Population (household and group quarter)
- Households
- Household vehicles
- Employment (by employment category and zone of work)
- Labor force participation (by zone of residence)
- Area type

The principal data requirements of the OKI travel demand forecasting model are population and employment. From these variables, other characteristics including households, labor force, and personal vehicles may be derived. Chapter 5 of *OKI 2030 Regional Transportation Plan 2008 Update* provides a complete demographic overview of the region.

OKI utilizes both base year (2005) and future year data (2010, 2020 and 2030) in the planning process. Planning data are maintained at the Traffic Analysis Zone (TAZ) level, and originate in the 2000 Census of Population and Housing. Base year 2005 and future year data for each variable are developed through various methods. More detailed explanation of base year and future year data generation for each of the above-mentioned categories of planning data follows. All of the variables represent the latest OKI planning assumptions.

Population

Base and Future Year Data: Population data for base year 2005 and future years 2010, 2020 and 2030 originate with the 2000 Census of Population and Housing. Utilizing ArcView GIS, population data at the zonal level for 2000 was derived from the area proportion allocation of block level population.

As a tri-state regional planning agency, OKI uses county level projections as prepared by the respective state data centers (Ohio Department of Development Office of Strategic Research, Kentucky State Data Center and Indiana Business Research Center) as control totals. The most current projections (years 2005 to 2030) were released by the Ohio and Indiana state data centers in 2003 and the Kentucky State Data Center in 2004. Population projections at the zonal level are calculated by multiplying household size by the projected zonal households. Household size is factored so that, in each county, the sum of the zonal populations equals the control total.

Households

Base Year Data: Household data for base year 2005 originates with the 2000 Census of Population and Housing. Utilizing the geographic information system ArcMap, household data at the zonal level for 2000 was derived from the area proportion allocation of block level households. Year 2000 household data was updated to 2005 with residential building permits issued between January 2000 and December 2004. The residential building locations were geo-coded in ArcMap, then aggregated to the TAZs. The housing unit totals for each TAZ were converted to households by applying a vacancy rate, an adjustment for permitted but unbuilt units, and subtracting demolitions (where data was available). These households were then added to the year Census 2000 zonal household total to arrive at 2005 households for each TAZ.

Future Year Data: The preparation of household projections was accomplished by calculating the number of households for a projected county population using ratios of householders to total population by age specific cohorts derived from the 2000 Census for each analysis year. Disaggregation to TAZs was determined by historical trends, existing and future land use, topography, flood plain information, availability of land, local knowledge and other factors.

Household Vehicles

Base and Future Year Data: Base and future year household vehicle data were obtained from the 2000 Census of Population and Housing. The 2000 Census is the only source of household vehicle data available at the block group level. Average vehicles per household were calculated for block groups then applied to the TAZs associated with each block group. The 2005, 2010, 2020 and 2030 vehicles per household level was held at the 2000 level based on the fact that, since 2002, the number of vehicles per household has exceeded the number of drivers per household.

Labor Force

Base and Future Year Data: The OKI labor force is a function of the population as determined by a labor force participation ratio (the number of employed persons in the labor force per persons 16 and over). Household data for base year 2005 originates with the 2000 Census of Population and Housing. Utilizing the geographic information system ArcMap, household data at the zonal level for 2000 was derived

from the area proportion allocation of block group level employed labor force. The labor force projections for 2005, 2010, 2020 and 2030 were based on the most recent projections of national labor force participation rates by age and sex cohorts from the U.S. Department of Labor, Bureau of Labor Statistics for each of those years. These rates were then applied to the projected county age/sex cohorts and adjusted to eliminate the unemployed to arrive at a county employed labor force control total. Employed labor force at the zonal level is calculated by multiplying the labor force participation rate by the zonal population. The labor force participation rate is adjusted so that, in each county, the sum of the zonal labor force counts equals the control total.

Employment

Base Year Data: Quarterly Census of Employment and Wages (QCEW or ES202) data for 2005 was utilized as the primary tool to calculate employment at the zonal level. Individual business records containing physical location, number of employees and SIC code were geocoded through ArcMap and aggregated to the TAZ level. This data set was supplemented by other sources of data to complete the commuting employment picture in the OKI region. Each zone's employment was divided according to the SIC code into three classes (retail, office, industrial) based upon the potential for generating trips.

Future Year Data: For future year employment projection, calculation was first made of the employment at the regional level. At the regional level, employment is a calculation of the region's employed labor force minus workers who live in the region but commute out to work, plus workers who live outside the region but commute in to work. The regional total was disaggregated first to the county level based on historic trends and expected changes in the county's share of the region's employment and then to the TAZ level. Disaggregation to TAZs was determined by historical trends, existing and future land use, topography, flood plain information, availability of land, local knowledge and other factors.

Area Type

Base and Future Year Data: For each analysis year, each TAZ is assigned an area type designation as CBD, Urban, Suburban or Rural based on population and employment densities.

Model Calibration

OKI's Travel Demand Model has been validated to observed traffic volumes for the model base year 2005. The modeling network encompasses the entire ozone nonattainment area with the exception of Clinton County, Ohio. The modeling network also includes Greene, Miami and Montgomery counties in Ohio and the remainder of Dearborn County Indiana. The difference between estimated vehicle miles traveled (VMT) and 2005 observed VMT is less than 1%. A highway screenline analysis compares the screenline observed and simulated traffic volume discrepancies with the ODOT standard of maximum desirable deviation. The comparison shows that the model performs at a satisfactory level and all the errors were under the ODOT curve. Further information can be found in OKI's 2007 report, "*OKI/MVRPC Travel Demand Model Methodology/ Validation Report*". For the calibration, OKI used over 3000 traffic counts collected through 2006 by the Ohio Department of Transportation (ODOT), the Kentucky Transportation Cabinet, many county and local governments, transportation engineering consultants, and OKI. These traffic counts cover nearly 50% percent of the links in the OKI portion of the modeling

network. The methodology provides consistency with past emission inventory and conformity analysis work performed by OKI.

Local Inputs and Post-Model Processing

OKI incorporates a variety of sources of local data to both improve and confirm the accuracy of VMT, as well as other travel-related parameters. Free flow speeds used on the highway and transit networks are based on travel time studies performed locally. The OKI post-processing program, IMPACT, uses the loaded highway network to generate VMT by hour, VMT by speed distribution and VMT by facility type. These tables are then included as input into MOVES. Two separate sets of VMT tables are generated: one for the four Ohio counties plus Dearborn County Indiana, and a second for the three Kentucky counties. The VMT by hour tables utilize hourly traffic distribution and directional split factors for different roadway types as developed by OKI. The main source of the data was the permanent traffic counting stations located throughout the OKI region for the years of 2004-2006. This data was supplemented with data collected at coverage count stations (locations with counts taken on only one-two days). The stations were classified by area type: urban and rural, and functional classification: freeway, arterial and collector. Speeds representing various "loaded" conditions (with traffic volumes) are estimated using techniques from the 1997 Highway Capacity Manual. This permits the estimation of speeds as conditions vary from hour to hour on the different facility types throughout the region. The IMPACT program performs the appropriate summation by area and roadway type as well as regional totals. OKI has also developed seasonal conversion factors to adjust traffic volumes to summer conditions. The factors were derived from local data collected at permanent traffic counting stations during 1994-1997 utilizing the average daily traffic monthly conversion factors for June, July and August. Further information on OKI's IMPACT program is documented in the report, *"Travel Demand Model Summary Reporting and Impact Summary Reporting: OKI/MVRPC Travel Demand Model User's Guide", OKI 2003.*

APPENDIX

OKI Technical Documentation for Using EPA Motor Vehicle Emission Simulator (MOVES) 2010 to develop mobile Source Emissions

August 2010

1. Using MOVES

To determine specific emission profiles and inventory, user has to define the input data like area, time span, type of vehicles, road types, fuel types, emission producing processes etc. These data are stored in a run specification (RunSpec) XML file. Using graphical user interface, the user can modify all these attributes of the RunSpec. In the following sections, how input data is entered and modified is explained. All these input options are found in the navigation panel of Graphical User Interface of MOVES software.

1.1 Description

The description text box is useful to list the specifications of the RunSpec and to distinguish between the RunSpecs. We can provide a brief overview of the particular RunSpec. In all of our current RunSpecs, we have details such as analysis years, area and pollutants analyzed.

1.2 Scale/Calculation Type

In this option, we need to specify about the Domain/Scale and Calculation type. The Domain specifies the level of default data we need to use for analysis and also the scale of the analysis. We have used the County scale. The county scale requires user supplied local data for most inputs. We have selected "Emission Rates" as the calculation type.

1.3 Time Spans

This input panel has different time-related input data like time aggregation level, year of analysis, month of analysis, whether analysis day is weekday or weekend, and hours of analysis. In all of our runs, time aggregation level is considered as hour, which is the most disaggregated level possible in MOVES and it is also specified in EPA's technical guidance for all SIP runs. In In consultation with the states, the analysis years of 2005, 2008, 2011, 2015, 2018, and 2021 were selected. Each analysis year requires a separate MOVES run. We have used the month of April for analysis. Annual analysis uses one 24-hour set of average annual temperatures. The annual average minimum temperature, maximum temperature and humidity values for each hour were calculated and assigned the April month ID. The annual average temperature profile was used for the PM2.5 SIP inventory. Weekdays only, and all hours were selected.

1.4 Geographic Bounds

In this input screen, we need to specify the region of analysis (eg. Nation, State, Custom Domain). We have created a two separate input database through combining the four OKI Ohio counties (Hamilton, Butler, Clermont, and Warren) and the three OKI Kentucky counties (Boone, Campbell, and Kenton). Upon selecting the custom domain, MOVES will consider this region as separate generic County. The state ID is fixed as 99 and we have assigned an arbitrary CountyID of 390 for Ohio, and 210 for Kentucky to distinguish between the two states (39 and

21 are used in post-processing as state id's). The user also needs to provide a fraction geographic phase in area. In this case we do not have any phase in area fraction and we also provided average barometric pressure (MOVES default value for Hamilton County Ohio) to identify whether it is low altitude area or high altitude area. Since we do not have I/M program in the region the refueling program adjustment fraction and refueling spill program adjustment fractions are assigned as 0.00. In this input panel we also need to specify the Domain Input Databases. For all of our runs we have defined different input databases for each year.

1.5 Vehicles/Equipment

In MOVES, the user also needs to provide the different type of vehicles considered for analysis in the region. MOVES provide us with 13 different types of vehicles or equipment and four different fuel types and we need to select appropriate fuel and vehicle combinations. In MOVES, vehicle types are called SourceUseTypes . We have considered all possible types of fuel/vehicle type combinations.

1.6 Road Type

There are five road types available in MOVES. All five road types are selected in the RunSpecs, however OKI travel demand model does not predict the off-network vehicle miles traveled. The off-network road type in MOVES is used to assign activity for vehicle starts and for evaporative emissions while vehicles are parked. The other four road types are relatively simple and are based on area type, whether it is urban or rural. All expressways and freeways are considered as restricted roadways and all other road types are considered as unrestricted roadways.

1.7 Pollutants and Processes

There are different pollutants and corresponding processes are available in MOVES. A separate panel is available for selecting different pollutants and processes. In consultation with the states, PM2.5, NO_x, SO_2 were selected. To perform calculation of PM2.5 it is also required to select total energy consumption, elemental carbon, organic carbon, and sulfate particulate. In addition, brake wear and tire wear are also selected.

1.8 Miscellaneous

Information about present and future alternative vehicle fuels & technologies, on-road retrofit and rate of progress information can be input with the MOVES Strategies section of the RunSpec. If we do not specify future Alternative Vehicle Fuel & Technologies, MOVES is going to assume default alternative fuels. The default AVFT strategy file was modified to reflect 0% CNG buses in the transit fleet (default is 6%). MOVES also provides options whether we would like to save the MOVESactivityoutput and MOVESOutput databases or not. We did not select these options, although these were selected in subsequent runs as an error checking method, and to obtain values utilized in the post-processing.

Table 1.8 : Alternative Vehicle and Fueling Technology used in all RunSpecs

sourceTypeID	modelYearID	fuelTypeID	engTechID	fuelEngFraction
42	1960	2	1	1
42	1961	2	1	1
42	1962	2	1	1
42	1963	2	1	1
42	1964	2	1	1
42	1965	2	1	1
42	1966	2	1	1
42	1967	2	1	1
42	1968	2	1	1
42	1969	2	1	1
42	1970	2	1	1
42	1971	2	1	1
42	1972	2	1	1
42	1973	2	1	1
42	1974	2	1	1
42	1975	2	1	1
42	1976	2	1	1
42	1977	2	1	1
42	1978	2	1	1
42	1979	2	1	1
42	1980	2	1	1
42	1981	2	1	1
42	1982	2	1	1
42	1983	2	1	1
42	1984	2	1	1
42	1985	2	1	1
42	1986	2	1	1
42	1987	2	1	1
42	1988	2	1	1
42	1989	2	1	1
42	1990	2	1	1
42	1991	2	1	1
42	1992	2	1	1
42	1993	2	1	1
42	1994	2	1	1
42	1995	2	1	1
42	1996	2	1	1
42	1997	2	1	1
42	1998	2	1	1
42	1999	2	1	1
42	2000	2	1	1
42	2001	2	1	1
42	2002	2	1	1
42	2003	2	1	1

42	2004	2	1	1
42	2005	2	1	1
42	2006	2	1	1
42	2007	2	1	1
42	2008	2	1	1
42	2009	2	1	1
42	2010	2	1	1
42	2011	2	1	1
42	2012	2	1	1
42	2013	2	1	1
42	2014	2	1	1
42	2015	2	1	1
42	2016	2	1	1
42	2017	2	1	1
42	2018	2	1	1
42	2019	2	1	1
42	2020	2	1	1
42	2021	2	1	1
42	2022	2	1	1
42	2023	2	1	1
42	2024	2	1	1
42	2025	2	1	1
42	2026	2	1	1
42	2027	2	1	1
42	2028	2	1	1
42	2029	2	1	1
42	2030	2	1	1
42	2031	2	1	1
42	2032	2	1	1
42	2033	2	1	1
42	2034	2	1	1
42	2035	2	1	1
42	2036	2	1	1
42	2037	2	1	1
42	2038	2	1	1
42	2039	2	1	1
42	2040	2	1	1
42	2041	2	1	1
42	2042	2	1	1
42	2043	2	1	1
42	2044	2	1	1
42	2045	2	1	1
42	2046	2	1	1
42	2047	2	1	1
42	2048	2	1	1
42	2049	2	1	1
42	2050	2	1	1

1.9 Output

The MOVES output section requires the designation of an output database. A new database was created for each new RunSpec. Output units selected for mass, energy and distance were grams, joules and miles. Activity output was not selected. The second output screen requires further selection for data aggregation and data options. Hour was selected for Time, and County was selected for Location. Road Type and Source Type were also selected.

2. Data Importers

In order to enter local data into RunSpec, we need to use pre processing option in the MOVES. We can select either Data Importer or County Importer for Custom Domain option. These Importers convert the data in excel format to MySQL tables. This is the preferred input format of MOVES software.

2.1 Meteorology Data Importer

In this type of Importer, meteorology data is converted to a MOVES input format. This dataset has different data items like month ID, Zone ID, hour ID, Temperature and Relative Humidity. The Ohio and Kentucky custom domains use the identical temperature data obtained from the Kentucky Division for Air Quality (KDAQ). Even though ODOT has provided the temperature data (collected from local airports), KDAQ data appeared to be more applicable. A portion of the KDAQ temperature file is shown in Table 2.1. As previously discussed, annual average minimum and maximum temperatures and humidity values were calculated and used in the PM2.5 analysis.

Table 2.1 : Meteorology Data

monthID	zoneID	hourID	temperature	relHumidity
1	993900	1	23.2	100
1	993900	2	22.2	100
1	993900	3	21.4	100
1	993900	4	20.9	100
1	993900	5	20.4	100
1	993900	6	19.9	100
1	993900	7	19.5	100
1	993900	8	19.9	100
1	993900	9	22	100
1	993900	10	25.4	100
1	993900	11	28.9	87.6

1	993900	12	31.9	77.5
1	993900	13	34.5	69.7
1	993900	14	36	65.9
1	993900	15	36.5	64.6
1	993900	16	36.6	64.2
1	993900	17	36.2	65.1
1	993900	18	35.2	67.8
1	993900	19	33.5	72.6
1	993900	20	31.3	79.3
1	993900	21	29.1	86.8
1	993900	22	27.2	93.9
1	993900	23	25.8	99.4
1	993900	24	24.5	100

2.2 Source Type Population Importer

The source type population importer converts vehicle type, and registered vehicle population in into MOVES database format. ODOT has provided us with the registered vehicle population in each county in the Ohio portion of the region for 13 MOVES vehicle types. KYTC has provided registered vehicle population by county for 6 HPMS vehicle types. The KYTC data was converted to the 13 MOVES vehicle types based on the Ohio distribution. Same vehicle population was used for all analysis years. As per suggestions made by FHWA, the source type population has been forecasted for future years with +0.8 % per year. Similarly, the source type populations has been estimated for past years. The MOVES default source type population for intercity bus, refuse trucks, motor homes and combination trucks was used. In addition, MOVES default source type population for passenger trucks and light commercial trucks was used for Kentucky. The MOVES default source type population was acquired from the MOVES activity output tables from county-level inventory runs.

Table 2.21: Ohio Source Type Population (acquired from ODOT and default)

yearID	sourceTypeID	sourceTypePopulation
2008	11	68559
2008	21	1191067
2008	31	482420
2008	32	15817
2008	41	454
2008	42	81
2008	43	3651
2008	51	409
2008	52	366
2008	53	361
2008	54	4888
2008	61	4839

2008	62	5548

Table 2.22: Kentucky Source Type population (acquired from KYTC and default)

yearID	sourceTypeID	sourceTypePopulation
2008	11	7975
2008	21	197009
2008	31	120518
2008	32	40263
2008	41	127
2008	42	21
2008	43	977
2008	51	115
2008	52	761
2008	53	751
2008	54	1379
2008	61	1580
2008	62	1811

2.3 Age Distribution Importer

For emission calculation, MOVES requires vehicle Age Distribution by Source Type. Vehicle Age Distribution is divided into 30 years based on vehicle model years. For each vehicle type, the distribution sum adds up to one. ODOT has obtained vehicle registration data from the Ohio Bureau of Motor Vehicles for all the counties in Ohio and processed them to convert into MOVES Age Distribution for 13 vehicle types. KYTC also provided vehicle registration data. We have used the same Age Distribution for all year runs. All the vehicles older than 30 years are considered as 30-years old. Identical age distribution is used for all analysis years. KYTC also provided similar information, but for the 6 HPMS types only. For Kentucky, identical age distributions are used within each HPMS vehicle type.

Table 2.3: Ohio Custom Domain Age distribution

Source TypeID	yearID	ageID	ageFraction
11	2008	0	0.0019
11	2008	1	0.0191
11	2008	2	0.0531
11	2008	3	0.0688
11	2008	4	0.0773
11	2008	5	0.0737
11	2008	6	0.0611
11	2008	7	0.0780
11	2008	8	0.0636
11	2008	9	0.0537
11	2008	10	0.0435
11	2008	11	0.0359
11	2008	12	0.0282
11	2008	13	0.0230
11	2008	14	0.0220
11	2008	15	0.0183
11	2008	16	0.0160
11	2008	17	0.0146
11	2008	18	0.0097
11	2008	19	0.0080
11	2008	20	0.0072
11	2008	21	0.0086

11	2008	22	0.0084
11	2008	23	0.0121
11	2008	24	0.0171
11	2008	25	0.0179
11	2008	26	0.0137
11	2008	27	0.0171
11	2008	28	0.0249
11	2008	29	0.0172
11	2008	30	0.0862
21	2008	0	0.0121
21	2008	1	0.0331
21	2008	2	0.0440
21	2008	3	0.0528
21	2008	4	0.0534
21	2008	5	0.0566
21	2008	6	0.0570
21	2008	7	0.0592
21	2008	8	0.0591
21	2008	9	0.0542
21	2008	10	0.0590
21	2008	11	0.0568
21	2008	12	0.0507
21	2008	13	0.0499
21	2008	14	0.0438
21	2008	15	0.0453
21	2008	16	0.0368
21	2008	17	0.0308
21	2008	18	0.0261
21	2008	19	0.0207
21	2008	20	0.0165
21	2008	21	0.0132
21	2008	22	0.0095
21	2008	23	0.0073
21	2008	24	0.0059
21	2008	25	0.0043
21	2008	26	0.0033
21	2008	27	0.0017
21	2008	28	0.0011
21	2008	29	0.0010
21	2008	30	0.0346
31	2008	0	0.0103
31	2008	1	0.0279
31	2008	2	0.0502
31	2008	3	0.0570
31	2008	4	0.0659
31	2008	5	0.0806
31	2008	6	0.0796
31	2008	7	0.0733
31	2008	8	0.0727
31	2008	9	0.0599
31	2008	10	0.0625
31	2008	11	0.0603
31	2008	12	0.0516
31	2008	13	0.0432
31	2008	14	0.0380
31	2008	15	0.0386
31	2008	16	0.0302
31	2008	17	0.0260
31	2008	18	0.0165
31	2008	19	0.0125
31	2008	20	0.0093
31	2008	21	0.0084
31	2008	22	0.0067
31	2008	23	0.0051
31	2008	24	0.0037
31	2008	25	0.0025
31	2008	26	0.0017
31	2008	27	0.0009
31	2008	28	0.0004
31	2008	29	0.0002
31	2008	30	0.0041
32	2008	0	0.0178
32	2008	1	0.0459
32	2008	2	0.0871
32	2008	3	0.0699
32	2008	4	0.0707
32	2008	5	0.0357
32	2008	6	0.0355
32	2008	7	0.0369
32	2008	8	0.0366
32	2008	9	0.0407
32	2008	10	0.0491
32	2008	11	0.0547
32	2008	12	0.0427
32	2008	13	0.0413
32	2008	14	0.0383
32	2008	15	0.0602
32	2008	16	0.0476
32	2008	17	0.0381
32	2008	18	0.0304
32	2008	19	0.0181
32	2008	20	0.0212
32	2008	21	0.0184
32	2008	22	0.0135
32	2008	23	0.0134
32	2008	24	0.0095
32	2008	25	0.0070
32	2008	26	0.0054

32	2008	27	0.0021
32	2008	28	0.0014
32	2008	29	0.0008
32	2008	30	0.0100
41	2008	0	0.0000
41	2008	1	0.0309
41	2008	2	0.0884
41	2008	3	0.0890
41	2008	4	0.0768
41	2008	5	0.0746
41	2008	6	0.0967
41	2008	7	0.0635
41	2008	8	0.0486
41	2008	9	0.0801
41	2008	10	0.0751
41	2008	11	0.0624
41	2008	12	0.0254
41	2008	13	0.0271
41	2008	14	0.0188
41	2008	15	0.0193
41	2008	16	0.0133
41	2008	17	0.0177
41	2008	18	0.0094
41	2008	19	0.0177
41	2008	20	0.0171
41	2008	21	0.0099
41	2008	22	0.0039
41	2008	23	0.0055
41	2008	24	0.0061
41	2008	25	0.0011
41	2008	26	0.0033
41	2008	27	0.0033
41	2008	28	0.0028
41	2008	29	0.0017
41	2008	30	0.0105
42	2008	0	0.0000
42	2008	1	0.0366
42	2008	2	0.1098
42	2008	3	0.0366
42	2008	4	0.1585
42	2008	5	0.0366
42	2008	6	0.0610
42	2008	7	0.0610
42	2008	8	0.0244
42	2008	9	0.1098
42	2008	10	0.0366
42	2008	11	0.0976
42	2008	12	0.0366
42	2008	13	0.0244

42	2008	14	0.0244
42	2008	15	0.0122
42	2008	16	0.0244
42	2008	17	0.0244
42	2008	18	0.0366
42	2008	19	0.0000
42	2008	20	0.0000
42	2008	21	0.0122
42	2008	22	0.0000
42	2008	23	0.0000
42	2008	24	0.0000
42	2008	25	0.0000
42	2008	26	0.0122
42	2008	27	0.0000
42	2008	28	0.0000
42	2008	29	0.0122
42	2008	30	0.0122
43	2008	0	0.0905
43	2008	1	0.0302
43	2008	2	0.0549
43	2008	3	0.0467
43	2008	4	0.0592
43	2008	5	0.0723
43	2008	6	0.0481
43	2008	7	0.0334
43	2008	8	0.0668
43	2008	9	0.0647
43	2008	10	0.0842
43	2008	11	0.0864
43	2008	12	0.0473
43	2008	13	0.0500
43	2008	14	0.0242
43	2008	15	0.0185
43	2008	16	0.0106
43	2008	17	0.0228
43	2008	18	0.0109
43	2008	19	0.0130
43	2008	20	0.0125
43	2008	21	0.0092
43	2008	22	0.0062
43	2008	23	0.0079
43	2008	24	0.0090
43	2008	25	0.0035
43	2008	26	0.0030
43	2008	27	0.0011
43	2008	28	0.0027
43	2008	29	0.0016
43	2008	30	0.0087
51	2008	0	0.0054

51	2008	1	0.0488
51	2008	2	0.0623
51	2008	3	0.0705
51	2008	4	0.0867
51	2008	5	0.0434
51	2008	6	0.0434
51	2008	7	0.0542
51	2008	8	0.0542
51	2008	9	0.0759
51	2008	10	0.0217
51	2008	11	0.0407
51	2008	12	0.0786
51	2008	13	0.0542
51	2008	14	0.0515
51	2008	15	0.0678
51	2008	16	0.0325
51	2008	17	0.0081
51	2008	18	0.0163
51	2008	19	0.0027
51	2008	20	0.0081
51	2008	21	0.0000
51	2008	22	0.0027
51	2008	23	0.0027
51	2008	24	0.0136
51	2008	25	0.0000
51	2008	26	0.0000
51	2008	27	0.0000
51	2008	28	0.0027
51	2008	29	0.0000
51	2008	30	0.0515
52	2008	0	0.0054
52	2008	1	0.0488
52	2008	2	0.0623
52	2008	3	0.0705
52	2008	4	0.0867
52	2008	5	0.0434
52	2008	6	0.0434
52	2008	7	0.0542
52	2008	8	0.0542
52	2008	9	0.0759
52	2008	10	0.0217
52	2008	11	0.0407
52	2008	12	0.0786
52	2008	13	0.0542
52	2008	14	0.0515
52	2008	15	0.0678
52	2008	16	0.0325
52	2008	17	0.0081
52	2008	18	0.0163

52	2008	19	0.0027
52	2008	20	0.0081
52	2008	21	0.0000
52	2008	22	0.0027
52	2008	23	0.0027
52	2008	24	0.0136
52	2008	25	0.0000
52	2008	26	0.0000
52	2008	27	0.0000
52	2008	28	0.0027
52	2008	29	0.0000
52	2008	30	0.0515
53	2008	0	0.0000
53	2008	1	0.0062
53	2008	2	0.0373
53	2008	3	0.0093
53	2008	4	0.0280
53	2008	5	0.0342
53	2008	6	0.0186
53	2008	7	0.0186
53	2008	8	0.0124
53	2008	9	0.0155
53	2008	10	0.0217
53	2008	11	0.0373
53	2008	12	0.0093
53	2008	13	0.0311
53	2008	14	0.0217
53	2008	15	0.0373
53	2008	16	0.0217
53	2008	17	0.0342
53	2008	18	0.0124
53	2008	19	0.0186
53	2008	20	0.0248
53	2008	21	0.0373
53	2008	22	0.0186
53	2008	23	0.0248
53	2008	24	0.0062
53	2008	25	0.0373
53	2008	26	0.0155
53	2008	27	0.0186
53	2008	28	0.0217
53	2008	29	0.0186
53	2008	30	0.3509
54	2008	0	0.0077
54	2008	1	0.0170
54	2008	2	0.0377
54	2008	3	0.0424
54	2008	4	0.0471
54	2008	5	0.0579

54	2008	6	0.0552
54	2008	7	0.0485
54	2008	8	0.0406
54	2008	9	0.0439
54	2008	10	0.0505
54	2008	11	0.0539
54	2008	12	0.0435
54	2008	13	0.0360
54	2008	14	0.0348
54	2008	15	0.0375
54	2008	16	0.0303
54	2008	17	0.0231
54	2008	18	0.0196
54	2008	19	0.0150
54	2008	20	0.0183
54	2008	21	0.0208
54	2008	22	0.0218
54	2008	23	0.0217
54	2008	24	0.0186
54	2008	25	0.0173
54	2008	26	0.0163
54	2008	27	0.0118
54	2008	28	0.0084
54	2008	29	0.0059
54	2008	30	0.0968
61	2008	0	0.0030
61	2008	1	0.0167
61	2008	2	0.0334
61	2008	3	0.0393
61	2008	4	0.0506
61	2008	5	0.0530
61	2008	6	0.0620
61	2008	7	0.0625
61	2008	8	0.0562
61	2008	9	0.0551
61	2008	10	0.0595
61	2008	11	0.0569
61	2008	12	0.0458
61	2008	13	0.0493
61	2008	14	0.0380
61	2008	15	0.0435
61	2008	16	0.0425
61	2008	17	0.0312
61	2008	18	0.0262
61	2008	19	0.0235
61	2008	20	0.0201
61	2008	21	0.0225
61	2008	22	0.0212
61	2008	23	0.0141
61	2008	24	0.0137
61	2008	25	0.0096
61	2008	26	0.0069
61	2008	27	0.0039
61	2008	28	0.0030
61	2008	29	0.0027
61	2008	30	0.0343
62	2008	0	0.0078
62	2008	1	0.0232
62	2008	2	0.0307
62	2008	3	0.0907
62	2008	4	0.0721
62	2008	5	0.0808
62	2008	6	0.0564
62	2008	7	0.0520
62	2008	8	0.0360
62	2008	9	0.0552
62	2008	10	0.1019
62	2008	11	0.0813
62	2008	12	0.0603
62	2008	13	0.0425
62	2008	14	0.0439
62	2008	15	0.0442
62	2008	16	0.0273
62	2008	17	0.0202
62	2008	18	0.0122
62	2008	19	0.0101
62	2008	20	0.0103
62	2008	21	0.0080
62	2008	22	0.0079
62	2008	23	0.0058
62	2008	24	0.0050
62	2008	25	0.0036
62	2008	26	0.0038
62	2008	27	0.0001
62	2008	28	0.0012
62	2008	29	0.0010
62	2008	30	0.0046

Table 2 : Kentucky Custom Domain Age distribution

Source TypeID	yearID	ageID	ageFraction
11	2008	0	0.0020
11	2008	1	0.0323
11	2008	2	0.0606
11	2008	3	0.0826
11	2008	4	0.0831
11	2008	5	0.0774
11	2008	6	0.0667
11	2008	7	0.0830
11	2008	8	0.0650
11	2008	9	0.0495
11	2008	10	0.0424
11	2008	11	0.0345
11	2008	12	0.0287
11	2008	13	0.0214
11	2008	14	0.0240
11	2008	15	0.0208
11	2008	16	0.0138
11	2008	17	0.0129
11	2008	18	0.0092
11	2008	19	0.0051
11	2008	20	0.0052
11	2008	21	0.0058
11	2008	22	0.0078
11	2008	23	0.0108
11	2008	24	0.0153
11	2008	25	0.0168
11	2008	26	0.0124
11	2008	27	0.0160
11	2008	28	0.0228
11	2008	29	0.0152
11	2008	30	0.0568
21	2008	0	0.0118
21	2008	1	0.0665
21	2008	2	0.0596
21	2008	3	0.0642
21	2008	4	0.0611
21	2008	5	0.0705
21	2008	6	0.0694
21	2008	7	0.0699
21	2008	8	0.0719
21	2008	9	0.0619
21	2008	10	0.0633
21	2008	11	0.0591
21	2008	12	0.0490
21	2008	13	0.0442
21	2008	14	0.0348
21	2008	15	0.0318
21	2008	16	0.0241
21	2008	17	0.0191
21	2008	18	0.0142
21	2008	19	0.0111
21	2008	20	0.0088
21	2008	21	0.0066
21	2008	22	0.0049
21	2008	23	0.0039
21	2008	24	0.0028
21	2008	25	0.0024
21	2008	26	0.0018
21	2008	27	0.0009
21	2008	28	0.0005
21	2008	29	0.0005
21	2008	30	0.0094
31	2008	0	0.0000
31	2008	1	0.0000
31	2008	2	0.0000
31	2008	3	0.0000
31	2008	4	0.0238
31	2008	5	0.0119
31	2008	6	0.0119
31	2008	7	0.0119
31	2008	8	0.0119
31	2008	9	0.0000
31	2008	10	0.0238
31	2008	11	0.0357
31	2008	12	0.0119
31	2008	13	0.0952
31	2008	14	0.0833
31	2008	15	0.0595
31	2008	16	0.1071
31	2008	17	0.0357
31	2008	18	0.0357
31	2008	19	0.0357
31	2008	20	0.0119
31	2008	21	0.0476
31	2008	22	0.0238
31	2008	23	0.0119
31	2008	24	0.0119
31	2008	25	0.0595

31	2008	26	0.0357
31	2008	27	0.0000
31	2008	28	0.0238
31	2008	29	0.0238
31	2008	30	0.1548
32	2008	0	0.0000
32	2008	1	0.0000
32	2008	2	0.0000
32	2008	3	0.0000
32	2008	4	0.0238
32	2008	5	0.0119
32	2008	6	0.0119
32	2008	7	0.0119
32	2008	8	0.0119
32	2008	9	0.0000
32	2008	10	0.0238
32	2008	11	0.0357
32	2008	12	0.0119
32	2008	13	0.0952
32	2008	14	0.0833
32	2008	15	0.0595
32	2008	16	0.1071
32	2008	17	0.0357
32	2008	18	0.0357
32	2008	19	0.0357
32	2008	20	0.0119
32	2008	21	0.0476
32	2008	22	0.0238
32	2008	23	0.0119
32	2008	24	0.0119
32	2008	25	0.0595
32	2008	26	0.0357
32	2008	27	0.0000
32	2008	28	0.0238
32	2008	29	0.0238
32	2008	30	0.1548
41	2008	0	0.0455
41	2008	1	0.1136
41	2008	2	0.0000
41	2008	3	0.0114
41	2008	4	0.0227
41	2008	5	0.0000
41	2008	6	0.0000
41	2008	7	0.0114
41	2008	8	0.0114
41	2008	9	0.0227
41	2008	10	0.0114
41	2008	11	0.0568
41	2008	12	0.1250

41	2008	13	0.0227
41	2008	14	0.0000
41	2008	15	0.0341
41	2008	16	0.0341
41	2008	17	0.0682
41	2008	18	0.0455
41	2008	19	0.0909
41	2008	20	0.0568
41	2008	21	0.0455
41	2008	22	0.0341
41	2008	23	0.0455
41	2008	24	0.0227
41	2008	25	0.0227
41	2008	26	0.0114
41	2008	27	0.0000
41	2008	28	0.0227
41	2008	29	0.0000
41	2008	30	0.0114
42	2008	0	0.0455
42	2008	1	0.1136
42	2008	2	0.0000
42	2008	3	0.0114
42	2008	4	0.0227
42	2008	5	0.0000
42	2008	6	0.0000
42	2008	7	0.0114
42	2008	8	0.0114
42	2008	9	0.0227
42	2008	10	0.0114
42	2008	11	0.0568
42	2008	12	0.1250
42	2008	13	0.0227
42	2008	14	0.0000
42	2008	15	0.0341
42	2008	16	0.0341
42	2008	17	0.0682
42	2008	18	0.0455
42	2008	19	0.0909
42	2008	20	0.0568
42	2008	21	0.0455
42	2008	22	0.0341
42	2008	23	0.0455
42	2008	24	0.0227
42	2008	25	0.0227
42	2008	26	0.0114
42	2008	27	0.0000
42	2008	28	0.0227
42	2008	29	0.0000
42	2008	30	0.0114

43	2008	0	0.0455
43	2008	1	0.1136
43	2008	2	0.0000
43	2008	3	0.0114
43	2008	4	0.0227
43	2008	5	0.0000
43	2008	6	0.0000
43	2008	7	0.0114
43	2008	8	0.0114
43	2008	9	0.0227
43	2008	10	0.0114
43	2008	11	0.0568
43	2008	12	0.1250
43	2008	13	0.0227
43	2008	14	0.0000
43	2008	15	0.0341
43	2008	16	0.0341
43	2008	17	0.0682
43	2008	18	0.0455
43	2008	19	0.0909
43	2008	20	0.0568
43	2008	21	0.0455
43	2008	22	0.0341
43	2008	23	0.0455
43	2008	24	0.0227
43	2008	25	0.0227
43	2008	26	0.0114
43	2008	27	0.0000
43	2008	28	0.0227
43	2008	29	0.0000
43	2008	30	0.0114
51	2008	0	0.0025
51	2008	1	0.0200
51	2008	2	0.0386
51	2008	3	0.0436
51	2008	4	0.0495
51	2008	5	0.0579
51	2008	6	0.0667
51	2008	7	0.0698
51	2008	8	0.0620
51	2008	9	0.0611
51	2008	10	0.0675
51	2008	11	0.0619
51	2008	12	0.0508
51	2008	13	0.0529
51	2008	14	0.0397
51	2008	15	0.0397
51	2008	16	0.0375
51	2008	17	0.0276
51	2008	18	0.0204
51	2008	19	0.0184
51	2008	20	0.0158
51	2008	21	0.0174
51	2008	22	0.0152
51	2008	23	0.0108
51	2008	24	0.0108
51	2008	25	0.0071
51	2008	26	0.0052
51	2008	27	0.0031
51	2008	28	0.0021
51	2008	29	0.0021
51	2008	30	0.0220
52	2008	0	0.0025
52	2008	1	0.0200
52	2008	2	0.0386
52	2008	3	0.0436
52	2008	4	0.0495
52	2008	5	0.0579
52	2008	6	0.0667
52	2008	7	0.0698
52	2008	8	0.0620
52	2008	9	0.0611
52	2008	10	0.0675
52	2008	11	0.0619
52	2008	12	0.0508
52	2008	13	0.0529
52	2008	14	0.0397
52	2008	15	0.0397
52	2008	16	0.0375
52	2008	17	0.0276
52	2008	18	0.0204
52	2008	19	0.0184
52	2008	20	0.0158
52	2008	21	0.0174
52	2008	22	0.0152
52	2008	23	0.0108
52	2008	24	0.0108
52	2008	25	0.0071
52	2008	26	0.0052
52	2008	27	0.0031
52	2008	28	0.0021
52	2008	29	0.0021
52	2008	30	0.0220
53	2008	0	0.0025
53	2008	1	0.0200
53	2008	2	0.0386
53	2008	3	0.0436
53	2008	4	0.0495

53	2008	5	0.0579
53	2008	6	0.0667
53	2008	7	0.0698
53	2008	8	0.0620
53	2008	9	0.0611
53	2008	10	0.0675
53	2008	11	0.0619
53	2008	12	0.0508
53	2008	13	0.0529
53	2008	14	0.0397
53	2008	15	0.0397
53	2008	16	0.0375
53	2008	17	0.0276
53	2008	18	0.0204
53	2008	19	0.0184
53	2008	20	0.0158
53	2008	21	0.0174
53	2008	22	0.0152
53	2008	23	0.0108
53	2008	24	0.0108
53	2008	25	0.0071
53	2008	26	0.0052
53	2008	27	0.0031
53	2008	28	0.0021
53	2008	29	0.0021
53	2008	30	0.0220
54	2008	0	0.0025
54	2008	1	0.0200
54	2008	2	0.0386
54	2008	3	0.0436
54	2008	4	0.0495
54	2008	5	0.0579
54	2008	6	0.0667
54	2008	7	0.0698
54	2008	8	0.0620
54	2008	9	0.0611
54	2008	10	0.0675
54	2008	11	0.0619
54	2008	12	0.0508
54	2008	13	0.0529
54	2008	14	0.0397
54	2008	15	0.0397
54	2008	16	0.0375
54	2008	17	0.0276
54	2008	18	0.0204
54	2008	19	0.0184
54	2008	20	0.0158
54	2008	21	0.0174
54	2008	22	0.0152

54	2008	23	0.0108
54	2008	24	0.0108
54	2008	25	0.0071
54	2008	26	0.0052
54	2008	27	0.0031
54	2008	28	0.0021
54	2008	29	0.0021
54	2008	30	0.0220
61	2008	0	0.0000
61	2008	1	0.0064
61	2008	2	0.0295
61	2008	3	0.0205
61	2008	4	0.0321
61	2008	5	0.0346
61	2008	6	0.0423
61	2008	7	0.0308
61	2008	8	0.0269
61	2008	9	0.0179
61	2008	10	0.0462
61	2008	11	0.0410
61	2008	12	0.0359
61	2008	13	0.0513
61	2008	14	0.0333
61	2008	15	0.0359
61	2008	16	0.0423
61	2008	17	0.0269
61	2008	18	0.0295
61	2008	19	0.0231
61	2008	20	0.0385
61	2008	21	0.0397
61	2008	22	0.0333
61	2008	23	0.0346
61	2008	24	0.0295
61	2008	25	0.0192
61	2008	26	0.0346
61	2008	27	0.0128
61	2008	28	0.0141
61	2008	29	0.0128
61	2008	30	0.1244
62	2008	0	0.0000
62	2008	1	0.0064
62	2008	2	0.0295
62	2008	3	0.0205
62	2008	4	0.0321
62	2008	5	0.0346
62	2008	6	0.0423
62	2008	7	0.0308
62	2008	8	0.0269
62	2008	9	0.0179

62	2008	10	0.0462
62	2008	11	0.0410
62	2008	12	0.0359
62	2008	13	0.0513
62	2008	14	0.0333
62	2008	15	0.0359
62	2008	16	0.0423
62	2008	17	0.0269
62	2008	18	0.0295
62	2008	19	0.0231
62	2008	20	0.0385
62	2008	21	0.0397
62	2008	22	0.0333
62	2008	23	0.0346
62	2008	24	0.0295
62	2008	25	0.0192
62	2008	26	0.0346
62	2008	27	0.0128
62	2008	28	0.0141
62	2008	29	0.0128
62	2008	30	0.1244

2.4 Vehicle Type VMT and VMT Fractions

This option is useful to import the annual VMT by source type into MOVES format. It has input option as HPMS Base Year VMT, for which we can either use HPMS data or the Travel Demand Model output. We have used daily VMT from the OKI Regional Travel Demand Model and converted to annual VMT using the VMT converter. Options include Month VMT fraction, Day VMT fraction and Hour VMT fraction, which are useful for calculating emissions for different time periods. We have used default Monthly VMT distribution factors provided in the VMT Converter provided by EPA. Hourly distribution factors are developed from traffic count data collected in the region from 2004-2006 and the same set of hourly distribution factors are used for all vehicle types and road types. OKI model could only predict VMT of two different vehicle types' autos and trucks. So, we have distributed total Annual VMT based on vehicle population in the region.

Table 2.41 : Annual VMT for Ohio Custom Domain from OKI travel demand model for 2005

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2005	67065022	0
20	2005	7405961237	0
30	2005	4943917030	0
40	2005	24512225	0
50	2005	334351024	0
60	2005	567810955	0

Table 2.41a :Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2005

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2005	16658465	0
20	2005	1815341688	0
30	2005	1209494070	0
40	2005	5968488	0
50	2005	82065068	0
60	2005	160708291	0

Table 2.42: Annual VMT for Ohio Custom Domain from OKI travel demand model for 2008

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	69438850	0
20	2008	7668102136	0
30	2008	5118911580	0
40	2008	25379858	0
50	2008	346185690	0
60	2008	587909153	0

Table 2.42a : Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2008

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	17342291	0
20	2008	1889861055	0
30	2008	1259143528	0
40	2008	6213493	0
50	2008	85433821	0
60	2008	167305330	0

Table 2.43: Annual VMT for Ohio Custom Domain from OKI travel demand model for 2011

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	69438850.44	0
20	2008	7668102136	0
30	2008	5118911580	0
40	2008	25379858.39	0
50	2008	346185689.5	0
60	2008	587909153	0

Table2.43a: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2011

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2011	18163152	0
20	2011	1979313603	0
30	2011	1318742406	0
40	2011	6507596	0
50	2011	89477649	0
60	2011	175224371	0

Table 2.44 : Annual VMT for Ohio Custom Domain from OKI travel demand model for 2015

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2015	73413634	0
20	2015	8107035747	0
30	2015	5411925719	0
40	2015	26832639	0
50	2015	366001875	0
60	2015	621561950	0

Table 2.44a: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2015

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2015	19903870	0

20	2015	2169006811	0
30	2015	1445127874	0
40	2015	7131270	0
50	2015	98052996	0
60	2015	192017502	0

Table 2.45: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2018

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2018	76802311	0
20	2018	8481245879	0
30	2018	5661733109	0
40	2018	28071199	0
50	2018	382896041	0
60	2018	650252434	0

Table 2.45a: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2018

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2018	21077884	0
20	2018	2296944011	0
30	2018	1530367631	0
40	2018	7551902	0
50	2018	103836577	0
60	2018	203343507	0

Table 2.46 : Annual VMT for Ohio Custom Domain from OKI travel demand model for 2021

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2021	79128218	0
20	2021	8738094842	0
30	2021	5833194979	0
40	2021	28921317	0
50	2021	394491797	0
60	2021	669944902	0

Table 2.46a : Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2021

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2021	21702396	0
20	2021	2364999583	0
30	2021	1575710506	0
40	2021	7775656	0
50	2021	106913124	0
60	2021	209368320	0

Table 2.47 : Day VMT Fractions used in all RunSpecs

sourceTypeID	monthID	roadTypeID	dayID	dayVMTFraction
11	1	1	2	0.237635
11	1	1	5	0.762365
11	1	2	2	0.237635
11	1	2	5	0.762365
11	1	3	2	0.237635
11	1	3	5	0.762365
11	1	4	2	0.237635
11	1	4	5	0.762365
11	1	5	2	0.237635
11	1	5	5	0.762365

Table 2.48: Hour VMT Fractions used in all RunSpecs

sourceTypeID	roadTypeID	dayID	hourID	hourVMTFraction
11	1	2	1	0.021474
11	1	2	2	0.014443
11	1	2	3	0.010968
11	1	2	4	0.007495
11	1	2	5	0.006839
11	1	2	6	0.010359
11	1	2	7	0.01843
11	1	2	8	0.026812
11	1	2	9	0.036385
11	1	2	10	0.047541
11	1	2	11	0.057466
11	1	2	12	0.065079
11	1	2	13	0.071323
11	1	2	14	0.071492
11	1	2	15	0.071723
11	1	2	16	0.072006
11	1	2	17	0.071149
11	1	2	18	0.067887
11	1	2	19	0.061772
11	1	2	20	0.051688
11	1	2	21	0.042866
11	1	2	22	0.03803
11	1	2	23	0.032207
11	1	2	24	0.024568

2.5 Average Speed Distribution Importer

This importer allows the user to input average speed data specific to vehicle type, road type, and time of day/ type of day. The MOVES model defines 16 "speed bins" which describe the average driving speed on each road type. Unlike MOBILE 6.2 model, which uses VMT-based speed distribution, MOVES uses fraction of driving time in each speed bin for each vehicle type, for each road type, and for each hour. Thus, for each combination of vehicle type, road type, and hour/day type, the fractions will add to one. This importer was not used for the PM2.5 analysis. OKI utilized a FORTRAN program to post-process OKI Travel Demand Model results into VHT distribution by the MOVES 16 average speed bins.

2.6 Road Type Distribution Importer

VHT distribution by the fives MOVES roadway types is provided from the OKI Travel Demand Model thru the use of post-processing FORTRAN program. OKI travel demand model can calculate the VMT or VHT distribution by functional class, which is further processed to obtain road type VMT/VHT distribution. But, our model could not predict off network VMT, which is assumed as zero.

2.7 Ramp Fraction Importer

This option allows the user to modify the fraction of ramp driving time on selected road types. But, in the current version of MOVES model (MOVES2010), the emission rates for ramps are erroneously calculated. To circumvent this problem, FHWA has suggested a temporary solution. This solution discussed in the Section 3.

2.8 Fuel Formulation Importer and Fuel Supply Importer

The Fuel formulation importer allows the user to select an existing fuel in the MOVES database and change its properties, or create a new fuel formulation with different fuel properties. But we have used only default fuels available in MOVES default database. The default values were verified by ODOT and KDAQ. Fuel supply importer allows the user to assign existing fuels to counties, months, and years, and the associated market share for each fuel. We have used default fuel supply from MOVES default database. The same type of fuel is used for the entire custom domain.

Table 2.81 : Fuel supply data for Ohio Custom Domain (same for all years)

countyID	fuelYearID	monthGroupID	fuelFormulationID	marketShare	marketShareCV
99390	2008	1	3982	1	
99390	2008	1	20011	1	

99390	2008	2	3982	1
99390	2008	2	20011	1
99390	2008	3	3982	1
99390	2008	3	20011	1
99390	2008	4	3982	1
99390	2008	4	20011	1
99390	2008	5	3982	1
99390	2008	5	20011	1
99390	2008	6	3982	1
99390	2008	6	20011	1
99390	2008	7	3982	1
99390	2008	7	20011	1
99390	2008	8	3982	1
99390	2008	8	20011	1
99390	2008	9	3982	1
99390	2008	9	20011	1
99390	2008	10	3982	1
99390	2008	10	20011	1
99390	2008	11	3982	1
99390	2008	11	20011	1
99390	2008	12	3982	1
99390	2008	12	20011	1

Table2.82: Fuel supply data for Kentucky Custom Domain (same for all years)

countyID	fuelYearID	monthGroupID	fuelFormulationID	marketShare	marketShareCV
99210	2012	1	3982	1	
99210	2012	1	20011	1	
99210	2012	2	3982	1	
99210	2012	2	20011	1	
99210	2012	3	3982	1	
99210	2012	3	20011	1	
99210	2012	4	3982	1	
99210	2012	4	20011	1	
99210	2012	5	3982	1	
99210	2012	5	20011	1	
99210	2012	6	3982	1	
99210	2012	6	20011	1	
99210	2012	7	3982	1	
99210	2012	7	20011	1	
99210	2012	8	3982	1	
99210	2012	8	20011	1	
99210	2012	9	3982	1	
99210	2012	9	20011	1	
99210	2012	10	3982	1	
99210	2012	10	20011	1	
99210	2012	11	3982	1	

99210	2012	11	20011	1
99210	2012	12	3982	1
99210	2012	12	20011	1

2.9 Inspection and Maintenance (I/M) Importer

The I/M Importer allows the user to import information describing the inspection and maintenance programs. The MOVES default database includes an I/M program for this regional although it was suspended in 2005. The default I/M program was turned "off" for all analysis years 2008 and later, by inserting "N" in the "useIMyn" field.

2.10 Zone Road Activity Importer

The Zone Road Activity Importer is used only if the Custom Domain option is chosen in the County Domain Manager. We have used value 1 for SHOallocfactor for each road type which means that all of the VMT input by the users is assigned to custom domain.

Table 2.11 : Kentucky Custom Domain Zone road activity data (same for all years)

zoneID	roadTypeID	SHOAllocFactor
992100	1	1
992100	2	1
992100	3	1
992100	4	1
992100	5	1

Table 2.12 : Ohio Custom Domain Zone road activity data (same for all years)

zoneID	roadTypeID	SHOAllocFactor
993900	1	1
993900	2	1
993900	3	1
993900	4	1
993900	5	1

3. Ramp Inventory Runs

As discussed earlier, current version of the MOVES (MOVES2010) model cannot calculate Emission Rates for Ramps. To deal with this problem, FHWA has suggested an approach. The steps involved in this method are: (a) Calculating Emission Inventory for Urban Restricted and Rural Restricted road types keeping Ramp fraction as 1 (b) Finding out total VMT of Urban Restricted and Rural Restricted road types using MOVESactivityoutput option (c) Calculation

Emission Rates for Ramps through dividing Emission Inventory with VMT (d) Finally, using the Emission Rates in post processing for calculating regional Emission Inventory.

Table 3.1 :Ramp fraction Input

roadTypeID	rampFraction
2	1
4	1

4. Post-Processing of MOVES Output

4.1 Linking SQL tables to Microsoft Access

Microsoft Access 2007 was used for the post-processing. An ODBC connection with the MOVES output directory was established. Information on how to link or import SQL tables to Access can be found in the MOVES Users Guide.

4.2 Creating Emission Rate Lookup Tables

The ratepervehicle and rateperdistance SQL tables, one set for each state (Kentucky and Ohio) and analysis year, were imported into Access. Ohio emission rates are used for the nonattainment portion of Dearborn County Indiana. Rateperprofile output was not generated by MOVES because evaporative output was not selected (i.e. VOC). Tables were renamed with state and analysis year in the format OH_20xxrateperdistance. All rateperdistance tables were merged with a Union query. The SQL commands are shown in Figure 4.21. ratepervehicle tables were merged in the same manner.

Table 4.21 :Rateperdistance Union Query

```
SELECT *
FROM OH_2008rateperdistance
WHERE MOVESRunID = (select max (MOVESRunID) from OH_2008rateperdistance) AND
pollutantID = 3 Or MOVESRunID =  (select max (MOVESRunID) from
OH_2008rateperdistance) AND pollutantID=110 Or MOVESRunID =  (select max
(MOVESRunID) from OH_2008rateperdistance) AND pollutantID=116 Or MOVESRunID =
(select max (MOVESRunID) from OH_2008rateperdistance) AND pollutantID=117 Or
MOVESRunID = (select max (MOVESRunID) from OH_2008rateperdistance) AND
pollutantID = 31
UNION ALL select *
FROM OH_2011rateperdistance
WHERE ….. (repeated for each file)
```

"Rateperdistance_state" and "Ratepervehicle_state" tables were created from the union query output using a Make Table query. Emission rates for each process were summed by pollutant and a stateID field is created. The SQL commands for creating the "Rateperdistance_state" table are shown in Table 4.22. Unique index fields were identified for each of the two tables. Indexes facilitate more efficient data processing.

Table 4.22: Rateperdistance_State Query

```
SELECT Val(Mid([LinkID],3,2)) AS StateID, Union_rateperdistance_state.yearID,
Union_rateperdistance_state.monthID, Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.sourceTypeID,
Union_rateperdistance_state.roadTypeID,
Union_rateperdistance_state.avgSpeedBinID,
Union_rateperdistance_state.pollutantID,
Sum(Union_rateperdistance_state.ratePerDistance) AS SumOfratePerDistance INTO
rateperdistance_state
```

```
FROM Union_rateperdistance_state
GROUP BY Val(Mid([LinkID],3,2)), Union_rateperdistance_state.yearID,
Union_rateperdistance_state.monthID, Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.sourceTypeID,
Union_rateperdistance_state.roadTypeID,
Union_rateperdistance_state.avgSpeedBinID,
Union_rateperdistance_state.pollutantID
ORDER BY Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.pollutantID;
```

4.3 Creating a VMT Table by County

The VMT table includes Daily VMT by county by analysis year from the OKI Travel Demand Model (TDM). Summer factors and applied by functional class to create Summer VMT. Seasonal factors by functional class are contained in the report, "OKI Travel Demand Forecasting Model, Update of Hourly and Seasonal Factors as Used in Air Quality Impact Calculations", September 2001. Annual VMT is calculated by using EPA's VMT converter to grow daily VMT to annual VMT. In order to accommodate an error in MOVES 2010, all VMT values are exclusive of ramp VMT. Ramp VMT and emission are added in later in the process. In order to apply the emission rates, it is necessary to factor the county VMT by source type, hour, road type and speed bin.

Table 4.3 : VMT and Source Type Population by County and Year

County	Daily VMT	Summer VMT	Annual VMT	yearID	SourceType Population	stateID
Boone	3924117	4186006	1273226984	2005	129823	21
Boone	4076584	4355527	1350001557	2008	134028	21
Boone	4383716	4681593	1448879510	2011	136181	21
Boone	4950741	5276742	1628041303	2015	140590	21
Boone	5260102	5597287	1729595179	2018	143991	21
Boone	5478224	5826768	1800571708	2021	147476	21
Campbell	2286217	2437698	741790605	2005	86065	21
Campbell	2339542	2495174	774762729	2008	88853	21
Campbell	2421600	2582758	800372702	2011	90279	21
Campbell	2663159	2844504	875774499	2015	93204	21
Campbell	2771476	2958827	911300109	2018	95458	21
Campbell	2849127	3041704	936445364	2021	97768	21
Kenton	3927743	4182042	1274091658	2005	148193	21
Kenton	3927332	4185652	1300575265	2008	152992	21
Kenton	4049886	4327836	1338544021	2011	155451	21
Kenton	4341124	4614242	1427569992	2015	160484	21
Kenton	4629694	4880614	1522308203	2018	164368	21
Kenton	4715306	5006383	1549817345	2021	168343	21
Butler	578641	7804476	196737836	2005	24915	39

Butler	587582	8133554	199777880	2008	25722	39
Butler	605620	8454053	205910800	2011	26135	39
Butler	657778	8768598	223644400	2015	26982	39
Butler	684361	9232457	232682740	2018	27635	39
Butler	706828	9592567	240321520	2021	28303	39
Clermont	7452286	5391578	2469166037	2005	401759	39
Clermont	7745685	5599530	2598059212	2008	414771	39
Clermont	8050701	5841102	2693716250	2011	421434	39
Clermont	8361487	6035155	2792188144	2015	435082	39
Clermont	8806042	6314640	2940849935	2018	445608	39
Clermont	9150031	6562428	2966037449	2021	456389	39
Dearborn NA	5083331	599761	1684259908	2005	232380	39
Dearborn NA	5262489	613027	1765145113	2008	239906	39
Dearborn NA	5489545	631914	1836768820	2011	243760	39
Dearborn NA	5687698	685272	1899318043	2015	251654	39
Dearborn NA	5952603	712461	1987920583	2018	257742	39
Dearborn NA	6186441	735862	2005371969	2021	263978	39
Hamilton	21859452	23170766	7241529618	2005	862422	39
Hamilton	22124503	23447460	7421005221	2008	890352	39
Hamilton	22426021	23803187	7503612070	2011	904655	39
Hamilton	22849494	24259554	7630232069	2015	933953	39
Hamilton	23630554	25096560	7891617279	2018	956548	39
Hamilton	24098698	25596996	7811737549	2021	979689	39
Warren	5884216	6263010	1949617151	2005	233106	39
Warren	6057338	6464217	2031753523	2008	240655	39
Warren	6406284	6835660	2143504189	2011	244521	39
Warren	6842828	7279441	2285055662	2015	252440	39
Warren	7368035	7836746	2460615706	2018	258547	39
Warren	7707500	8194596	2498432370	2021	264802	39

4.4 Source type population and source type VMT distribution

A combination of local and MOVES default data were used for the source type populations. The source type VMT fractions are based on the ratio of MOVES default source type population and MOVES default source type VMT. It is assumed that the growth rate of source type populations is equal to the regional annual household growth rate of 0.8%. Source type VMT fractions are the same for all analysis years.

Table 4.4: Base Year Source Type Population and VMT Fraction

stateID	sourceTypeID	sourceTypePopulation	sourceTypeFraction	sourceTypeVMTFraction
39	11	69121	0.038559	0.005026
39	21	1200827	0.669872	0.555019
39	31	486373	0.271319	0.277725
39	32	15947	0.008896	0.092783
39	41	458	0.000255	0.000754
39	42	82	0.000046	0.000225
39	43	3681	0.002053	0.000858
39	51	0	0.000000	0.000644
39	52	369	0.000206	0.020527
39	53	364	0.000203	0.002663
39	54	4928	0.002749	0.001224
39	61	4879	0.002722	0.017977
39	62	5593	0.003120	0.024576
21	11	8040	0.021370	0.005063
21	21	198623	0.527931	0.551736
21	31	121506	0.322958	0.275546
21	32	40593	0.107894	0.092055
21	41	128	0.000340	0.000745
21	42	21	0.000056	0.000222
21	43	985	0.002618	0.000847
21	51	0	0.000000	0.000641
21	52	767	0.002039	0.020433
21	53	757	0.002012	0.002650
21	54	1390	0.003695	0.001218
21	61	1593	0.004234	0.020634
21	62	1826	0.004853	0.028210

4.5 Hourly distribution

Hourly distribution factors were derived from OKI's traffic count database using 2004-2006 counts.

4.6 Road type distribution

Road type VMT fractions by source type are default values, except for passenger cars (source type 21) and passenger trucks (source type 31). VMT fractions from the OKI TDM are used for passenger cars and passenger trucks.

Table 4.6: Base Year Source Type Population and VMT Fraction

sourceTypeID	roadTypeID	roadTypeVMTFraction	stateID
21	1	0	21
21	2	0.0952	21
21	3	0.0818	21
21	4	0.4741	21
21	5	0.3489	21
31	1	0	21
31	2	0.0952	21
31	3	0.0818	21
31	4	0.4741	21
31	5	0.3489	21
21	1	0	39
21	2	0.0436	39
21	3	0.1256	39
21	4	0.4143	39
21	5	0.4165	39
31	1	0	39
31	2	0.0436	39
31	3	0.1256	39
31	4	0.4143	39
31	5	0.4165	39

4.7 Average speed distribution

Average speed fractions for each of the 16 speed bins are provided by the OKI TDM. The average speed fractions vary by state, year, road type and hour.

Table 4.7: Average Speed Distribution (Example: only road type 2, year 2011, Ohio values shown)

roadTypeID	hourID	avgSpeedBinID	avgSpeedFraction	YearID	stateID
2	1	1	0.00000000	2011	39
2	1	2	0.00000000	2011	39
2	1	3	0.00000000	2011	39
2	1	4	0.00000000	2011	39
2	1	5	0.00000000	2011	39
2	1	6	0.00000000	2011	39
2	1	7	0.00000000	2011	39
2	1	8	0.00000000	2011	39

2	1	9	0.00000000	2011	39
2	1	10	0.11922233	2011	39
2	1	11	0.12547629	2011	39
2	1	12	0.19752816	2011	39
2	1	13	0.00589550	2011	39
2	1	14	0.00000000	2011	39
2	1	15	0.55187773	2011	39
2	1	16	0.00000000	2011	39
2	2	1	0.00000000	2011	39
2	2	2	0.00000000	2011	39
2	2	3	0.00000000	2011	39
2	2	4	0.00000000	2011	39
2	2	5	0.00000000	2011	39
2	2	6	0.00000000	2011	39
2	2	7	0.00000000	2011	39
2	2	8	0.00000000	2011	39
2	2	9	0.00000000	2011	39
2	2	10	0.11922233	2011	39
2	2	11	0.12547629	2011	39
2	2	12	0.19752816	2011	39
2	2	13	0.00589550	2011	39
2	2	14	0.00000000	2011	39
2	2	15	0.55187773	2011	39
2	2	16	0.00000000	2011	39
2	3	1	0.00000000	2011	39
2	3	2	0.00000000	2011	39
2	3	3	0.00000000	2011	39
2	3	4	0.00000000	2011	39
2	3	5	0.00000000	2011	39
2	3	6	0.00000000	2011	39
2	3	7	0.00000000	2011	39
2	3	8	0.00000000	2011	39
2	3	9	0.00000000	2011	39
2	3	10	0.11922233	2011	39
2	3	11	0.12547629	2011	39
2	3	12	0.19752816	2011	39
2	3	13	0.00589550	2011	39
2	3	14	0.06436270	2011	39

2	3	15	0.48751503	2011	39
2	3	16	0.00000000	2011	39
2	4	1	0.00000000	2011	39
2	4	2	0.00000000	2011	39
2	4	3	0.00000000	2011	39
2	4	4	0.00000000	2011	39
2	4	5	0.00000000	2011	39
2	4	6	0.00000000	2011	39
2	4	7	0.00000000	2011	39
2	4	8	0.00000000	2011	39
2	4	9	0.00000000	2011	39
2	4	10	0.11922233	2011	39
2	4	11	0.12547629	2011	39
2	4	12	0.19752816	2011	39
2	4	13	0.00589550	2011	39
2	4	14	0.12369152	2011	39
2	4	15	0.42818621	2011	39
2	4	16	0.00000000	2011	39
2	5	1	0.00000000	2011	39
2	5	2	0.00000000	2011	39
2	5	3	0.00000000	2011	39
2	5	4	0.00000000	2011	39
2	5	5	0.00000000	2011	39
2	5	6	0.00000000	2011	39
2	5	7	0.00000000	2011	39
2	5	8	0.00000000	2011	39
2	5	9	0.00000000	2011	39
2	5	10	0.11922233	2011	39
2	5	11	0.12547629	2011	39
2	5	12	0.26189086	2011	39
2	5	13	0.09782827	2011	39
2	5	14	0.06250896	2011	39
2	5	15	0.33307330	2011	39
2	5	16	0.00000000	2011	39
2	6	1	0.00000000	2011	39
2	6	2	0.12369152	2011	39
2	6	3	0.03260396	2011	39
2	6	4	0.03085494	2011	39

2	6	5	0.01601927	2011	39
2	6	6	0.01563475	2011	39
2	6	7	0.00000000	2011	39
2	6	8	0.00000000	2011	39
2	6	9	0.00000000	2011	39
2	6	10	0.11922233	2011	39
2	6	11	0.12547629	2011	39
2	6	12	0.19752816	2011	39
2	6	13	0.00589550	2011	39
2	6	14	0.00278921	2011	39
2	6	15	0.33028409	2011	39
2	6	16	0.00000000	2011	39
2	7	1	0.21880443	2011	39
2	7	2	0.00000000	2011	39
2	7	3	0.00278921	2011	39
2	7	4	0.00000000	2011	39
2	7	5	0.01131028	2011	39
2	7	6	0.03548550	2011	39
2	7	7	0.03519436	2011	39
2	7	8	0.03514937	2011	39
2	7	9	0.00617093	2011	39
2	7	10	0.08564905	2011	39
2	7	11	0.14691446	2011	39
2	7	12	0.13064235	2011	39
2	7	13	0.00589550	2011	39
2	7	14	0.14352342	2011	39
2	7	15	0.14247115	2011	39
2	7	16	0.00000000	2011	39
2	8	1	0.21880443	2011	39
2	8	2	0.00278921	2011	39
2	8	3	0.01131028	2011	39
2	8	4	0.01356074	2011	39
2	8	5	0.05711912	2011	39
2	8	6	0.03514937	2011	39
2	8	7	0.02902228	2011	39
2	8	8	0.01193860	2011	39
2	8	9	0.07229727	2011	39
2	8	10	0.05473480	2011	39

2	8	11	0.08493157	2011	39
2	8	12	0.11645227	2011	39
2	8	13	0.04360641	2011	39
2	8	14	0.20648097	2011	39
2	8	15	0.04180267	2011	39
2	8	16	0.00000000	2011	39
2	9	1	0.21880443	2011	39
2	9	2	0.00000000	2011	39
2	9	3	0.00000000	2011	39
2	9	4	0.00000000	2011	39
2	9	5	0.00000000	2011	39
2	9	6	0.00278921	2011	39
2	9	7	0.00000000	2011	39
2	9	8	0.04679577	2011	39
2	9	9	0.03519436	2011	39
2	9	10	0.08369185	2011	39
2	9	11	0.14590244	2011	39
2	9	12	0.15349370	2011	39
2	9	13	0.02733367	2011	39
2	9	14	0.03771092	2011	39
2	9	15	0.24828365	2011	39
2	9	16	0.00000000	2011	39
2	10	1	0.15629548	2011	39
2	10	2	0.04687421	2011	39
2	10	3	0.01563475	2011	39
2	10	4	0.00000000	2011	39
2	10	5	0.00000000	2011	39
2	10	6	0.00000000	2011	39
2	10	7	0.00000000	2011	39
2	10	8	0.00000000	2011	39
2	10	9	0.00000000	2011	39
2	10	10	0.11922233	2011	39
2	10	11	0.13957578	2011	39
2	10	12	0.18621788	2011	39
2	10	13	0.00589550	2011	39
2	10	14	0.04428952	2011	39
2	10	15	0.28599457	2011	39
2	10	16	0.00000000	2011	39

2	11	1	0.06436270	2011	39
2	11	2	0.12278771	2011	39
2	11	3	0.01601927	2011	39
2	11	4	0.01563475	2011	39
2	11	5	0.00000000	2011	39
2	11	6	0.00000000	2011	39
2	11	7	0.00000000	2011	39
2	11	8	0.00000000	2011	39
2	11	9	0.00000000	2011	39
2	11	10	0.11922233	2011	39
2	11	11	0.13678656	2011	39
2	11	12	0.18900709	2011	39
2	11	13	0.00589550	2011	39
2	11	14	0.02285135	2011	39
2	11	15	0.30743274	2011	39
2	11	16	0.00000000	2011	39
2	12	1	0.06436270	2011	39
2	12	2	0.09193278	2011	39
2	12	3	0.04687421	2011	39
2	12	4	0.01563475	2011	39
2	12	5	0.00000000	2011	39
2	12	6	0.00000000	2011	39
2	12	7	0.00000000	2011	39
2	12	8	0.00000000	2011	39
2	12	9	0.00000000	2011	39
2	12	10	0.11922233	2011	39
2	12	11	0.12547629	2011	39
2	12	12	0.20031737	2011	39
2	12	13	0.00589550	2011	39
2	12	14	0.02285135	2011	39
2	12	15	0.30743274	2011	39
2	12	16	0.00000000	2011	39
2	13	1	0.06436270	2011	39
2	13	2	0.09193278	2011	39
2	13	3	0.04687421	2011	39
2	13	4	0.01563475	2011	39
2	13	5	0.00000000	2011	39
2	13	6	0.00000000	2011	39

2	13	7	0.00000000	2011	39
2	13	8	0.00000000	2011	39
2	13	9	0.00000000	2011	39
2	13	10	0.11922233	2011	39
2	13	11	0.12547629	2011	39
2	13	12	0.19752816	2011	39
2	13	13	0.00868471	2011	39
2	13	14	0.00000000	2011	39
2	13	15	0.33028409	2011	39
2	13	16	0.00000000	2011	39
2	14	1	0.06436270	2011	39
2	14	2	0.09193278	2011	39
2	14	3	0.03085494	2011	39
2	14	4	0.03165402	2011	39
2	14	5	0.00000000	2011	39
2	14	6	0.00000000	2011	39
2	14	7	0.00000000	2011	39
2	14	8	0.00000000	2011	39
2	14	9	0.00000000	2011	39
2	14	10	0.11922233	2011	39
2	14	11	0.12547629	2011	39
2	14	12	0.19752816	2011	39
2	14	13	0.00868471	2011	39
2	14	14	0.00000000	2011	39
2	14	15	0.33028409	2011	39
2	14	16	0.00000000	2011	39
2	15	1	0.06436270	2011	39
2	15	2	0.09193278	2011	39
2	15	3	0.04687421	2011	39
2	15	4	0.01563475	2011	39
2	15	5	0.00000000	2011	39
2	15	6	0.00000000	2011	39
2	15	7	0.00000000	2011	39
2	15	8	0.00000000	2011	39
2	15	9	0.00000000	2011	39
2	15	10	0.11922233	2011	39
2	15	11	0.12547629	2011	39
2	15	12	0.19752816	2011	39

2	15	13	0.00868471	2011	39
2	15	14	0.02285135	2011	39
2	15	15	0.30743274	2011	39
2	15	16	0.00000000	2011	39
2	16	1	0.12369152	2011	39
2	16	2	0.07947816	2011	39
2	16	3	0.01563475	2011	39
2	16	4	0.00000000	2011	39
2	16	5	0.00000000	2011	39
2	16	6	0.00000000	2011	39
2	16	7	0.00000000	2011	39
2	16	8	0.00000000	2011	39
2	16	9	0.00000000	2011	39
2	16	10	0.11922233	2011	39
2	16	11	0.13957578	2011	39
2	16	12	0.18621788	2011	39
2	16	13	0.00589550	2011	39
2	16	14	0.04428952	2011	39
2	16	15	0.28599457	2011	39
2	16	16	0.00000000	2011	39
2	17	1	0.20316968	2011	39
2	17	2	0.01563475	2011	39
2	17	3	0.00000000	2011	39
2	17	4	0.00000000	2011	39
2	17	5	0.00000000	2011	39
2	17	6	0.00000000	2011	39
2	17	7	0.00278921	2011	39
2	17	8	0.02487101	2011	39
2	17	9	0.05711912	2011	39
2	17	10	0.05722137	2011	39
2	17	11	0.15811770	2011	39
2	17	12	0.14489757	2011	39
2	17	13	0.05018502	2011	39
2	17	14	0.00000000	2011	39
2	17	15	0.28599457	2011	39
2	17	16	0.00000000	2011	39
2	18	1	0.15629548	2011	39
2	18	2	0.04687421	2011	39

2	18	3	0.01563475	2011	39
2	18	4	0.00000000	2011	39
2	18	5	0.00000000	2011	39
2	18	6	0.00000000	2011	39
2	18	7	0.00000000	2011	39
2	18	8	0.00000000	2011	39
2	18	9	0.00000000	2011	39
2	18	10	0.11922233	2011	39
2	18	11	0.13957578	2011	39
2	18	12	0.18621788	2011	39
2	18	13	0.00589550	2011	39
2	18	14	0.04428952	2011	39
2	18	15	0.28599457	2011	39
2	18	16	0.00000000	2011	39
2	19	1	0.00000000	2011	39
2	19	2	0.00000000	2011	39
2	19	3	0.00000000	2011	39
2	19	4	0.00000000	2011	39
2	19	5	0.06436270	2011	39
2	19	6	0.00000000	2011	39
2	19	7	0.05932882	2011	39
2	19	8	0.03260396	2011	39
2	19	9	0.00000000	2011	39
2	19	10	0.15007727	2011	39
2	19	11	0.14149556	2011	39
2	19	12	0.21316291	2011	39
2	19	13	0.00589550	2011	39
2	19	14	0.00000000	2011	39
2	19	15	0.33307330	2011	39
2	19	16	0.00000000	2011	39
2	20	1	0.00000000	2011	39
2	20	2	0.00000000	2011	39
2	20	3	0.00000000	2011	39
2	20	4	0.00000000	2011	39
2	20	5	0.00000000	2011	39
2	20	6	0.00000000	2011	39
2	20	7	0.00000000	2011	39
2	20	8	0.00000000	2011	39

2	20	9	0.00000000	2011	39
2	20	10	0.11922233	2011	39
2	20	11	0.12547629	2011	39
2	20	12	0.19752816	2011	39
2	20	13	0.00589550	2011	39
2	20	14	0.15629548	2011	39
2	20	15	0.39558226	2011	39
2	20	16	0.00000000	2011	39
2	21	1	0.00000000	2011	39
2	21	2	0.00000000	2011	39
2	21	3	0.00000000	2011	39
2	21	4	0.00000000	2011	39
2	21	5	0.00000000	2011	39
2	21	6	0.00000000	2011	39
2	21	7	0.00000000	2011	39
2	21	8	0.00000000	2011	39
2	21	9	0.00000000	2011	39
2	21	10	0.11922233	2011	39
2	21	11	0.12547629	2011	39
2	21	12	0.19752816	2011	39
2	21	13	0.00589550	2011	39
2	21	14	0.00000000	2011	39
2	21	15	0.55187773	2011	39
2	21	16	0.00000000	2011	39
2	22	1	0.00000000	2011	39
2	22	2	0.00000000	2011	39
2	22	3	0.00000000	2011	39
2	22	4	0.00000000	2011	39
2	22	5	0.00000000	2011	39
2	22	6	0.00000000	2011	39
2	22	7	0.00000000	2011	39
2	22	8	0.00000000	2011	39
2	22	9	0.00000000	2011	39
2	22	10	0.11922233	2011	39
2	22	11	0.12547629	2011	39
2	22	12	0.19752816	2011	39
2	22	13	0.00589550	2011	39
2	22	14	0.00000000	2011	39

2	22	15	0.55187773	2011	39
2	22	16	0.00000000	2011	39
2	23	1	0.00000000	2011	39
2	23	2	0.00000000	2011	39
2	23	3	0.00000000	2011	39
2	23	4	0.00000000	2011	39
2	23	5	0.00000000	2011	39
2	23	6	0.00000000	2011	39
2	23	7	0.00000000	2011	39
2	23	8	0.00000000	2011	39
2	23	9	0.00000000	2011	39
2	23	10	0.11922233	2011	39
2	23	11	0.12547629	2011	39
2	23	12	0.19752816	2011	39
2	23	13	0.00589550	2011	39
2	23	14	0.00000000	2011	39
2	23	15	0.55187773	2011	39
2	23	16	0.00000000	2011	39
2	24	1	0.00000000	2011	39
2	24	2	0.00000000	2011	39
2	24	3	0.00000000	2011	39
2	24	4	0.00000000	2011	39
2	24	5	0.00000000	2011	39
2	24	6	0.00000000	2011	39
2	24	7	0.00000000	2011	39
2	24	8	0.00000000	2011	39
2	24	9	0.00000000	2011	39
2	24	10	0.11922233	2011	39
2	24	11	0.12547629	2011	39
2	24	12	0.19752816	2011	39
2	24	13	0.00589550	2011	39
2	24	14	0.00000000	2011	39
2	24	15	0.55187773	2011	39
2	24	16	0.00000000	2011	39

4.8 Creating a VMT Table by State, Year, Source Type, Hour, Road Type, and Average Speed Bin

The 'StateVMT_MakeTableQuery' query creates a VMT Table by state, source type, hour, road type and average speed utilizing the VMT distribution factors described in 4.4, 4.5, 4.6 and 4.7. The SQL commands for this query are shown in Table 4.8.

Table 4.8 :State VMT Table Query

```
SELECT VMT_byBudgetArea.yearID, VMT_byBudgetArea.stateID,
VMT_byBudgetArea.budgetID, roadtypedistribution1.sourceTypeID,
hourvmtfraction.hourID, roadtypedistribution1.roadTypeID,
avgSpeedDistribution.avgSpeedBinID,
sourcetypepopulation.sourceTypeVMTFraction, hourvmtfraction.hourVMTFraction,
roadtypedistribution1.roadTypeVMTFraction,
avgSpeedDistribution.avgSpeedFraction, First(VMT_byBudgetArea.[Annual VMT])
AS [FirstOfAnnual VMT], First(VMT_byBudgetArea.[Daily VMT]) AS [FirstOfDaily
VMT], [FirstOfDaily
VMT]*[hourVMTFraction]*[sourceTypeVMTFraction]*[roadTypeVMTFraction]*[avgSpee
dFraction] AS DailyVMT, [FirstOfAnnual
VMT]*[sourceTypeVMTFraction]*[hourVMTFraction]*[roadTypeVMTFraction]*[avgSpee
dFraction] AS AnnualizedVMT INTO StateVMT_Table
FROM VMT_byBudgetArea INNER JOIN (((avgSpeedDistribution INNER JOIN
hourvmtfraction ON (avgSpeedDistribution.hourDayID = hourvmtfraction.hourID)
AND (avgSpeedDistribution.roadTypeID = hourvmtfraction.roadTypeID) AND
(avgSpeedDistribution.sourceTypeID = hourvmtfraction.sourceTypeID)) INNER
JOIN roadtypedistribution1 ON (avgSpeedDistribution.stateID =
roadtypedistribution1.stateID) AND (avgSpeedDistribution.roadTypeID =
roadtypedistribution1.roadTypeID) AND (avgSpeedDistribution.sourceTypeID =
roadtypedistribution1.sourceTypeID)) INNER JOIN sourcetypepopulation ON
(avgSpeedDistribution.sourceTypeID = sourcetypepopulation.sourceTypeID) AND
(avgSpeedDistribution.stateID = sourcetypepopulation.stateID)) ON
(VMT_byBudgetArea.yearID = avgSpeedDistribution.YearID) AND
(VMT_byBudgetArea.stateID = avgSpeedDistribution.stateID)
GROUP BY VMT_byBudgetArea.yearID, VMT_byBudgetArea.stateID,
VMT_byBudgetArea.budgetID, roadtypedistribution1.sourceTypeID,
hourvmtfraction.hourID, roadtypedistribution1.roadTypeID,
avgSpeedDistribution.avgSpeedBinID,
sourcetypepopulation.sourceTypeVMTFraction, hourvmtfraction.hourVMTFraction,
roadtypedistribution1.roadTypeVMTFraction,
avgSpeedDistribution.avgSpeedFraction
HAVING (((avgSpeedDistribution.avgSpeedFraction)>0))
ORDER BY VMT_byBudgetArea.yearID, VMT_byBudgetArea.stateID,
hourvmtfraction.hourID;
```

5. Combining VMT and Emission Rates; Calculating Total Emissions

5.1 Summarizing Distance-based Emissions by Source Type

The daily VMT and annual VMT in each state, year, hour, source type, road type, and speed bin is multiplied by the appropriate rate per distance for each pollutant. This query is shown in Table 5.1.

Table 5.1 :Emissions distance Query

```
SELECT StateVMT_Table.stateID, StateVMT_Table.budgetID,
StateVMT_Table.yearID, rateperdistance_state.monthID, StateVMT_Table.hourID,
StateVMT_Table.sourceTypeID, StateVMT_Table.roadTypeID,
StateVMT_Table.avgSpeedBinID, rateperdistance_state.pollutantID,
StateVMT_Table.DailyVMT, StateVMT_Table.AnnualizedVMT,
rateperdistance_state.SumOfratePerDistance, [DailyVMT]*[SumOfratePerDistance]
AS EmissionsDist, [AnnualizedVMT]*[SumOfratePerDistance] AS
AnnualEmissionsDist
FROM StateVMT_Table INNER JOIN rateperdistance_state ON
(StateVMT_Table.stateID = rateperdistance_state.StateID) AND
(StateVMT_Table.yearID = rateperdistance_state.yearID) AND
(StateVMT_Table.sourceTypeID = rateperdistance_state.sourceTypeID) AND
(StateVMT_Table.hourID = rateperdistance_state.hourID) AND
(StateVMT_Table.roadTypeID = rateperdistance_state.roadTypeID) AND
(StateVMT_Table.avgSpeedBinID = rateperdistance_state.avgSpeedBinID)
GROUP BY StateVMT_Table.stateID, StateVMT_Table.budgetID,
StateVMT_Table.yearID, rateperdistance_state.monthID, StateVMT_Table.hourID,
StateVMT_Table.sourceTypeID, StateVMT_Table.roadTypeID,
StateVMT_Table.avgSpeedBinID, rateperdistance_state.pollutantID,
StateVMT_Table.DailyVMT, StateVMT_Table.AnnualizedVMT,
rateperdistance_state.SumOfratePerDistance;
```

A second query further summarizes the emissions by source type. This is necessary in order to combine with vehicle-based emissions that are independent of road type and speed.

5.2 Summarizing Vehicle-based Emissions by Source type

The source population for each county, year, hour, and source type is multiplied by the rate per vehicle for each pollutant. This query is shown in Table 5.2.

Table 5.2: Emissions Vehicle Query

```
SELECT VMT_byBudgetArea.budgetID, VMT_byBudgetArea.stateID,
ratepervehicle_state.yearID, ratepervehicle_state.monthID,
ratepervehicle_state.hourID, ratepervehicle_state.sourceTypeID,
sourcetypepopulation.sourceTypeFraction,
VMT_byBudgetArea.SourceTypePopulation, ratepervehicle_state.pollutantID,
ratepervehicle_state.SumOfratePerVehicle,
((Nz([VMT_byBudgetArea]!sourceTypePopulation*[sourceTypeFraction],0)/24)) AS
STPop, Nz([VMT_byBudgetArea]!sourceTypePopulation*[sourceTypeFraction],0) AS
STPop2,
Nz([VMT_byBudgetArea]!sourceTypePopulation*[sourceTypeFraction]*[SumOfratePer
Vehicle],0) AS emissionsVehicle,
Nz(([VMT_byBudgetArea]!sourceTypePopulation*[sourceTypeFraction]*[SumOfratePe
rVehicle])*365,0) AS AnnualemissionsVehicle
FROM (sourcetypepopulation INNER JOIN ratepervehicle_state ON
(sourcetypepopulation.sourceTypeID = ratepervehicle_state.sourceTypeID) AND
(sourcetypepopulation.stateID = ratepervehicle_state.StateID)) INNER JOIN
VMT_byBudgetArea ON (ratepervehicle_state.StateID = VMT_byBudgetArea.stateID)
AND (ratepervehicle_state.yearID = VMT_byBudgetArea.yearID)
GROUP BY VMT_byBudgetArea.budgetID, VMT_byBudgetArea.stateID,
ratepervehicle_state.yearID, ratepervehicle_state.monthID,
ratepervehicle_state.hourID, ratepervehicle_state.sourceTypeID,
sourcetypepopulation.sourceTypeFraction,
VMT_byBudgetArea.SourceTypePopulation, ratepervehicle_state.pollutantID,
ratepervehicle_state.SumOfratePerVehicle;
```

5.3 Ramp Emissions

Ramp emission rates, calculated as discussed in Section 3, are multiplied by ramp VMT in each state, year and source type. This query is shown in Table 5.3.

Table 5.3: Ramp Emissions Query

```
SELECT VMT_byBudgetArea.stateID, VMT_byBudgetArea.yearID,
hourvmtfraction.hourID, hourvmtfraction.sourceTypeID,
hourvmtfraction.hourVMTFraction, ramp_rate.pollutantID,
VMT_byBudgetArea.[Ramp VMT], ([Ramp VMT]*[hourVMTFraction])/13 AS
HourlyRampVMT, ramp_rate.ramprate, [HourlyRampVMT]*[ramprate] AS
RampEmissions, ([HourlyRampVMT]*[ramprate])*340 AS RampEmissionsAnnual
FROM (hourvmtfraction INNER JOIN ramp_rate ON hourvmtfraction.hourID =
ramp_rate.hourID) INNER JOIN VMT_byBudgetArea ON (ramp_rate.yearID =
VMT_byBudgetArea.yearID) AND (ramp_rate.StateID = VMT_byBudgetArea.stateID)
WHERE (((hourvmtfraction.roadTypeID)=4))
ORDER BY VMT_byBudgetArea.stateID, VMT_byBudgetArea.yearID,
hourvmtfraction.hourID, hourvmtfraction.sourceTypeID, ramp_rate.pollutantID;
```

5.4 Summarizing Results

Distance-based emissions by source type, vehicle-based emissions by source type, and ramp emissions by source type are summed by state, year and pollutant. This query is shown below. This is also where criteria may be set for limiting the results. A sum of VMT and source type population is also useful as a verification that all steps were run properly. The appropriate monthID criteria should be set here. The annual average temperature profile is contained in April (monthID=4).

Table 5.41:Results by State Query

```
SELECT EmissionsDistance_bySourceType_State.stateID,
EmissionsDistance_bySourceType_State.budgetID, EmissionsDistance_bySourceType_State.yearID,
EmissionsDistance_bySourceType_State.pollutantName,
Sum(EmissionsDistance_bySourceType_State.SumOfDailyVMT) AS SumOfSumOfDailyVMT,
Sum(RampEmissions_Query_State.HourlyRampVMT) AS SumOfHourlyRampVMT1,
Sum(EmissionsDistance_bySourceType_State.SumOfAnnualizedVMT) AS SumOfSumOfAnnualizedVMT,
First(EmissionsVehicle_Query_State.SourceTypePopulation) AS FirstOfSourceTypePopulation,
Sum(EmissionsVehicle_Query_State.SourceTypePopulation) AS SumOfSourceTypePopulation,
Sum(EmissionsDistance_bySourceType_State.SumOfEmissionsDist) AS SumOfSumOfEmissionsDist,
Sum(EmissionsDistance_bySourceType_State.SumOfAnnualEmissionsDist) AS
SumOfSumOfAnnualEmissionsDist, Sum(Nz([emissionsVehicle],0)) AS EmissionsVeh,
Sum(Nz([AnnualemissionsVehicle],0)) AS AnnualEmissionsVeh,
Sum(RampEmissions_Query_State.RampEmissions) AS SumOfRampEmissions,
Sum(RampEmissions_Query_State.RampEmissionsAnnual) AS SumOfRampEmissionsAnnual,
(([SumOfSumOfEmissionsDist]+[EmissionsVeh]+[SumOfRampEmissions])/1000)*0.001102 AS
DailyEmissionsTONS,
(([SumOfSumOfAnnualEmissionsDist]+[AnnualEmissionsVeh]+[SumOfRampEmissionsAnnual])/1000)*0.0
01102 AS AnnualEmissionsTONS
FROM (EmissionsDistance_bySourceType_State LEFT JOIN EmissionsVehicle_Query_State ON
```

```
(EmissionsDistance_bySourceType_State.yearID = EmissionsVehicle_Query_State.yearID) AND
(EmissionsDistance_bySourceType_State.stateID = EmissionsVehicle_Query_State.stateID) AND
(EmissionsDistance_bySourceType_State.monthID = EmissionsVehicle_Query_State.monthID) AND
(EmissionsDistance_bySourceType_State.hourID = EmissionsVehicle_Query_State.hourID) AND
(EmissionsDistance_bySourceType_State.sourceTypeID = EmissionsVehicle_Query_State.sourceTypeID)
AND (EmissionsDistance_bySourceType_State.pollutantID = EmissionsVehicle_Query_State.pollutantID))
INNER JOIN RampEmissions_Query_State ON (EmissionsDistance_bySourceType_State.stateID =
RampEmissions_Query_State.stateID) AND (EmissionsDistance_bySourceType_State.yearID =
RampEmissions_Query_State.yearID) AND (EmissionsDistance_bySourceType_State.sourceTypeID =
RampEmissions_Query_State.sourceTypeID) AND (EmissionsDistance_bySourceType_State.pollutantID =
RampEmissions_Query_State.pollutantID) AND (EmissionsDistance_bySourceType_State.hourID =
RampEmissions_Query_State.hourID)
GROUP BY EmissionsDistance_bySourceType_State.stateID,
EmissionsDistance_bySourceType_State.budgetID, EmissionsDistance_bySourceType_State.yearID,
EmissionsDistance_bySourceType_State.pollutantName,
EmissionsDistance_bySourceType_State.monthID, EmissionsDistance_bySourceType_State.pollutantID
HAVING (((EmissionsDistance_bySourceType_State.monthID)=4));
```

County-level emissions are also calculated based on county VMT, as reported by the OKI Travel Demand Model. Table 5.42 shows the query for calculating the county level results.

Table 5.42:Results by County Query

```
SELECT VMT.State, VMT.County, EmissionsDistance_bySourceType_State.stateID,
EmissionsDistance_bySourceType_State.budgetID, EmissionsDistance_bySourceType_State.yearID,
EmissionsDistance_bySourceType_State.pollutantName, VMT.SourceTypePopulation, VMT.[Daily VMT],
VMT.[Annual VMT], VMT.[All Daily VMT], [Daily VMT]/[SumOfSumOfDailyVMT] AS CountyFraction,
Sum(EmissionsDistance_bySourceType_State.SumOfDailyVMT) AS SumOfSumOfDailyVMT,
Sum(RampEmissions_Query_State.HourlyRampVMT) AS SumOfHourlyRampVMT1,
Sum(EmissionsDistance_bySourceType_State.SumOfAnnualizedVMT) AS SumOfSumOfAnnualizedVMT,
First(EmissionsVehicle_Query_State.SourceTypePopulation) AS FirstOfSourceTypePopulation,
Sum(EmissionsVehicle_Query_State.SourceTypePopulation) AS SumOfSourceTypePopulation,
Sum(EmissionsDistance_bySourceType_State.SumOfEmissionsDist) AS SumOfSumOfEmissionsDist,
Sum(EmissionsDistance_bySourceType_State.SumOfAnnualEmissionsDist) AS
SumOfSumOfAnnualEmissionsDist, Sum(Nz([emissionsVehicle],0)) AS EmissionsVeh,
Sum(Nz([AnnualemissionsVehicle],0)) AS AnnualEmissionsVeh,
Sum(RampEmissions_Query_State.RampEmissions) AS SumOfRampEmissions,
Sum(RampEmissions_Query_State.RampEmissionsAnnual) AS SumOfRampEmissionsAnnual,
(([SumOfSumOfEmissionsDist]+[EmissionsVeh]+[SumOfRampEmissions])/1000)*0.001102 AS
DailyEmissionsTONS,
(([SumOfSumOfAnnualEmissionsDist]+[AnnualEmissionsVeh]+[SumOfRampEmissionsAnnual])/1000)*0.0
01102 AS AnnualEmissionsTONS, [DailyEmissionsTONS]*[CountyFraction] AS CountyDailyEmissions,
[AnnualEmissionsTONS]*[CountyFraction] AS CountyAnnualEmissions
FROM VMT INNER JOIN ((EmissionsDistance_bySourceType_State LEFT JOIN
EmissionsVehicle_Query_State ON (EmissionsDistance_bySourceType_State.pollutantID =
EmissionsVehicle_Query_State.pollutantID) AND (EmissionsDistance_bySourceType_State.sourceTypeID
= EmissionsVehicle_Query_State.sourceTypeID) AND (EmissionsDistance_bySourceType_State.hourID =
```

```
EmissionsVehicle_Query_State.hourID) AND (EmissionsDistance_bySourceType_State.monthID =
EmissionsVehicle_Query_State.monthID) AND (EmissionsDistance_bySourceType_State.stateID =
EmissionsVehicle_Query_State.stateID) AND (EmissionsDistance_bySourceType_State.yearID =
EmissionsVehicle_Query_State.yearID)) INNER JOIN RampEmissions_Query_State ON
(EmissionsDistance_bySourceType_State.hourID = RampEmissions_Query_State.hourID) AND
(EmissionsDistance_bySourceType_State.pollutantID = RampEmissions_Query_State.pollutantID) AND
(EmissionsDistance_bySourceType_State.sourceTypeID = RampEmissions_Query_State.sourceTypeID)
AND (EmissionsDistance_bySourceType_State.yearID = RampEmissions_Query_State.yearID) AND
(EmissionsDistance_bySourceType_State.stateID = RampEmissions_Query_State.stateID)) ON
(VMT.yearID = EmissionsDistance_bySourceType_State.yearID) AND (VMT.stateID =
EmissionsDistance_bySourceType_State.stateID)
GROUP BY VMT.State, VMT.County, EmissionsDistance_bySourceType_State.stateID,
EmissionsDistance_bySourceType_State.budgetID, EmissionsDistance_bySourceType_State.yearID,
EmissionsDistance_bySourceType_State.pollutantName, VMT.SourceTypePopulation, VMT.[Daily VMT],
VMT.[Annual VMT], VMT.[All Daily VMT], EmissionsDistance_bySourceType_State.monthID,
EmissionsDistance_bySourceType_State.pollutantID
HAVING (((EmissionsDistance_bySourceType_State.monthID)=4));
```

Appendix F

Section 110 Provisions and Infrastructure Submittal

Steven L. Beshear
Governor

Leonard K. Peters
Secretary

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601-1403
www.air.ky.gov

September 8, 2009

Stan Meiburg
Acting Regional Administrator
U.S. EPA, Region 4
Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30365

Dear Mr. Meiburg:

The Kentucky Energy and Environment Cabinet (EEC) hereby submits to the U.S. Environmental Protection Agency (EPA) a letter certifying that Kentucky's existing State Implementation Plan (SIP) contains Section 110 provisions that address the requirements for the $PM_{2.5}$, 8-hour ozone, and Lead National Ambient Air Quality Standards (NAAQS).

Under section 110(a)(1) and (2) of the Clean Air Act (CAA), all states are required to submit plans to provide for the implementation, maintenance, and enforcement of any new or revised National Ambient Air Quality Standard (NAAQS). Section 110(a)(1) and (2) require states to address basic program elements, including requirements for emissions inventories, monitoring, and modeling, among other things. States are required to submit SIPs to EPA which demonstrate that these basic program elements have been addressed within 3 years of the promulgation of any new or revised NAAQS. Subsections (A) through (M) of section 110(a)(2), set forth the elements that a state's program must contain in the SIP. The list of section 110(a)(2) NAAQS requirements and Kentucky's provisions are listed below.

Emission limits and other control measures: Section 110(a)(2)(A) of the CAA requires SIPs to include enforceable emission limits and other control measures, means or techniques, schedules or compliance and other related matters.

Kentucky Authority:

- Kentucky Revised Statute Chapter 224 Section 10-100 (KRS 224.10-100) provides the Energy and Environment Cabinet the authority to administer all rules, regulations and orders promulgated under Chapter 224, and to provide for the prevention, abatement, and control of all water, land, and air pollution.
- Chapter 50 *General Administrative Procedures*.

- Regulation 401 KAR 51:010 *Attainment Status Designations*, establishes nonattainment areas and timetables for these areas to achieve the standard. The division is in the process of updating this regulation to specify $PM_{2.5}$ as well as PM_{10} but, continues to use PM_{10} as the surrogate for $PM_{2.5}$ as recommended by U.S. EPA.
- Regulation 401 KAR 50:055 *General Compliance Requirements*. Section 1 Emissions shutdown and malfunction.
- Chapter 51 *Attainment and Maintenance of the National Ambient Air Quality Standards*.
- Regulation 401 KAR 51:005 *Purpose and General Provisions*. Section 3 Notification and Recordkeeping. Section 4 Monitoring Regs.
- Chapter 52 *Permits, Registrations, and Prohibitory Rules*.
- 401 KAR 52:020 *Title V Permits* establishes requirements for air contaminant sources located in Kentucky that are required to obtain a Title V permit.
- 401 KAR 52:030 *Federally-Enforceable Permits for Nonmajor Sources* establishes requirements for air contaminant sources located in Kentucky that accept emissions limitations to avoid the New Source Review requirements under Title I of the Clean Air Act or the Operating Permit Program requirements under Title V of the Clean Air Act.
- 401 KAR 52:040 *State-Origin Permits* establishes requirements for minor sources whose permits are not required to be federally enforceable.
- Regulation 401 KAR 53:010, *Ambient Air Quality Standards*. Serves to establish the requirement for regulations for the prevention, abatement, and control of air pollution.

Ambient air quality monitoring/data system: Section 110(a)(2)(B) of the CAA requires SIPs to include provisions to provide for establishment and operation of ambient air quality monitors, collecting and analyzing ambient air quality data, and presentation of these data available to EPA upon request.

Kentucky Authority:

- KRS 224.10-100 (22) requires the installation, maintenance, and use of equipment, devices, or test and methodologies to monitor the nature and amount of any substance emitted into the ambient air and to provide the information to the cabinet.
- Chapter 50 *General Administrative Procedures* spells out the requirements for monitoring.
- Regulation 401 KAR 51:017 *Prevention of Significant Deterioration of Air Quality* (PSD) applies to the construction of any new major stationary source or any project at an existing major stationary source in an area designated as attainment or unclassifiable.
- Regulation 401 KAR 50:050 authorize the monitoring of ambient air quality.
- Regulation 401 KAR 53:010 *Ambient Air Quality Standards* sets ambient air quality standards necessary for the protection of the public health, welfare, and property.
- Regulation 401 KAR 50:045 *Performance Test* establishes the requirements for these tests.

Program for enforcement of control measures: Section 110(a)(2)(C) of the CAA requires States to include a program that provides for enforcement of all SIP measures and the regulation of construction of new or modified stationary sources to meet prevention of significant deterioration (PSD) and nonattainment new source review (NSR) requirements.

Kentucky Authority:

- Chapter 51 *Attainment and Maintenance of the NAAQS.*
- Regulation 401 KAR 51:017 *Prevention of Significant Deterioration of Air Quality* applies to the construction of any new major stationary source or any project at an existing major stationary source in an area designated as attainment or unclassifiable. The division is in the process of updating this regulation to specify $PM_{2.5}$ as well as PM_{10} but, continues to use PM_{10} as the surrogate for $PM_{2.5}$ as recommended by U.S. EPA.
- Regulation 401 KAR 50:060 *Enforcement*, provides for enforcement of the terms and conditions of permits and compliance schedules.

Interstate transport: Section 110(a)(2)(D) of the CAA requires SIPs to include provisions prohibiting any source of other type of emissions activity in one state from contributing significantly to nonattainment of the NAAQS in another State. States are required to submit 110(a)(2)(D)(i) plans to demonstrate compliance with these provisions.

Kentucky Authority:

- Finding regarding section 110(a)(2)(D)(i) promulgated submitted on 12/10/07 for the 1997 8-hour ozone and $PM_{2.5}$ National Ambient Air Quality Standards..
- Kentucky submitted the 110(a)(1) plan on 12/7/07 for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS.
- Kentucky's Clean Air Interstate Rule (CAIR) was approved 10/4/07 (72 FR 56623)
- The Final Regional Haze SIP was submitted to U.S. EPA on 6/25/08.
- The Final 8-Hour Ozone Attainment Demonstration was submitted to U.S. EPA on 12/07/07.
- The Final $PM_{2.5}$ Attainment Demonstration was submitted to U.S. EPA on 12/03/08.

Adequate resources: Section 110(a)(2)(E) of the CAA requires states to provide for adequate personnel, funding and legal authority under State law to carry out its SIP and related issues.

Kentucky Authority:

- KRS 224.10-100 *Powers and Duties of the Cabinet*, provides for authority under State law to carry out its SIP and related issues.

- KRS 224.10-100 *Powers and Duties of the Cabinet*, Section (11) provides for the authority to accept, receive, and administer grants or other funds or gifts from public and private agencies including the federal government for the purpose of carrying out any fo the functions of the cabinet.
- Regulation 401 KAR 50:038 *Air Emissions Fee* provides for the assessment of fees necessary to fund the state Title V permit program.

Stationary source monitoring system: Section 110(a)(2)(F) of the CAA requires States to establish a system to monitor emissions from stationary sources and to submit periodic emissions reports.

Kentucky Authority:

- Chapter 50 *General Administrative Procedures*.
- Regulation 401 KAR 50:050 *Monitoring*, Section 1 Monitoring Records and Reporting establishes the requirements for the installation, use, and maintenance of stack gas and ambient air monitoring equipment.
- Regulation 401 KAR 50:055 *General Compliance Requirements*, Section 1 Emission During Shut Down Malfunction.

Emergency power: Section 110(a)(2)(G) of the CAA requires States to provide for authority to address activities causing imminent and substantial endangerment to public health, including contingency plans to implement the emergency episode provisions in their SIPs.

Kentucky Authority:

- Chapter 55 *Emergency Episodes*.
- Regulation 401 KAR 55:005 *Significant Harm Criteria*, Section 1 Purpose defines those levels of pollutant concentration which must be prevented in order to avoid significant harm to the health of persons.
- Regulation 401 KAR 55:010 *Episodic Criteria* defines those levels of pollutant concentrations which justify the proclamation of an air pollution alert, air pollution warning, an air pollution emergency.
- Regulation 401 KAR 55:015 *Episode Declaration* provides for the curtailment or reduction of processes or operations which emit an air contaminant or an air contaminant precursor whose criteria has been reached and are located in the affected areas for which an episode level has been declared.
- All of Kentucky is considered a Priority III Area, and therefore no emergency episode plan for $PM_{2.5}$ is required.
- An emergency episode was already included for the 1-hour ozone standard and would suffice for the 8-hour ozone standard.

Future SIP revisions: Section 110(a)(2)(H) of the CAA requires States to have the authority to revise their SIPs in response to changes in the NAAQS, availability of improved methods for attaining the NAAQS, or in response to an EPA finding that the SIP is substantially inadequate.

Kentucky Authority:

- Chapter 53 *Ambient Air Quality.*
- Regulation 401 KAR 53:010 *Ambient Air Quality Standards.*
- Regulation 401 KAR 51:010 *Attainment Status Designations* contains provisions for the cabinet to review applicable data and submit to U.S. EPA revisions to the attainment-nonattainment list pursuant to 42 USC 7407.

Consultation with government officials: Section 110(a)(2)(J) of the CAA requires States to provide a process for consultation with local governments and Federal Land Managers carrying out NAAQS implementation requirements pursuant to CAA Section 121 relating to consultation.

Kentucky Authority:

- Chapter 50 *General Administrative Procedures.*
- Regulation 401 KAR 51:017 *Prevention of Significant Deterioration of Air Quality.* Section 15 Public Participation.
- Regulation 401 KAR 52:100 *Public, Affected State, and U.S. EPA Review* establishes the procedures used by the cabinet to provide for the review of federally-enforceable permits by the public, affected states, and the U.S. EPA.
- Regulation 401 KAR 50:066 *Conformity of Transportation Plans, Programs, and Projects* establishes criteria and procedures for the interagency consultation process used in demonstrating conformity of federal transportation plans to the SIP.

Public notification: Section 110(a)(2)(J) of the CAA further requires States to notify the public if NAAQS are exceeded in an area and to enhance public awareness of measure that can be taken to prevent exceedances.

Kentucky Authority:

- Chapter 51 *Attainment and Maintenance of the National Ambient Air Quality Standards.*
- Regulation 401 KAR 51:017 *Prevention of Significant Deterioration (PSD) of Air Quality.* Section 15 Public Participation.

- Regulation 401 KAR 52:100 *Public, Affected State, and U.S. EPA Review* establishes the procedures used by the cabinet to provide for the review of federally-enforceable permits by the public, affected states, and the U.S. EPA.

PSD and visibility protection: Section 110(a)(2)(J) of the CAA also requires States to meet applicable requirements of Part C related to PSD and visibility protection.

Kentucky Authority:

- Chapter 51. *Attainment and Maintenance of the National Ambient Air Quality Standards.*
- Regulation 401 KAR 51:017 *Prevention of Significant Deterioration of Air Quality.*
- Regulation 401 KAR 63:005 *Open Burning* establishes requirements for the control of open burning.
- Regulation 401 KAR 63:010 *Fugitive Emissions* provides for the control of fugitive emissions.

Air quality modeling/data: Section 110(a)(2)(K) of the CAA requires that SIPs provide for performing air quality modeling so that effects on air quality of emissions from NAAQS pollutants can be predicted and submission of such data to EPA can be made.

Kentucky Authority:

- Chapter 50 *General Administrative Procedures.*
- Regulation 401 KAR 50:040 *Air Quality Models* specifies general provisions for the use of air quality models.
- Regulation 401 KAR 50:050 *Monitoring.*

Permitting fees: Section 110(a)(2)(L) of the CAA requires SIPs to require each major stationary source to pay permitting fees to cover the costs of reviewing, approving, implementing, and enforcing a permit.

Kentucky Authority:

- 401 KAR 50:038 *Air Emissions Fee* provides for the assessment of fees necessary to fund the state permit program.

Consultation/participation by affected local entities: Section 110(a)(2)(M) of the CAA requires States to provide for consultation and participation in SIP development by local political subdivision affected by the SIP.

Kentucky Authority:

- Chapter 65 *Mobile Source Related Emissions*.
- Regulation 401 KAR 50:066 *Conformity of Transportation Plans, Programs, and Projects*.
- Regulation 401 KAR 50:035 *Permits*. Section 7 Procedures for public participation.
- KRS Chapter 77 *Local Authority*.

If you have any questions or comments concerning this matter, please contact John Gowins at the Division for Air Quality at (502) 564-3999.

Sincerely,

John S. Lyons
Director

JSL:jeg

Appendix G

Kentucky Regulations (KAR)

CAIR

NO_x SIP Call

KY Cabinet Powers and Duties

Reasonably Available Control Measures

Open Burning

Fugitive Emissions

401 KAR 51:210. CAIR NOx annual trading program.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121, 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

STATUTORY AUTHORITY: KRS 224.10-100(5), 42 U.S.C. 7410

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100(5) requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation establishes requirements for the control of nitrogen oxides (NOx) emissions from large boilers and turbines used in power plants, pursuant to the federal mandate published under the Clean Air Interstate Rule (CAIR), 40 C.F.R. 96.101 to 96.188. This administrative regulation is not more stringent than the provisions allowed under the federal mandate.

Section 1. Applicability. This administrative regulation shall apply to CAIR NOx units in Kentucky that are subject to 40 C.F.R. 96.104.

Section 2. Compliance Requirements. CAIR NOx units shall comply with the following requirements:

(1) 40 C.F.R. 96.101 to 96.108 (Subpart AA), "CAIR NOx Annual Trading Program General Provisions";

(2) 40 C.F.R. 96.110 to 96.115 (Subpart BB), "CAIR Designated Representative for CAIR NOx Sources";

(3) 40 C.F.R. 96.120 to 96.124 (Subpart CC), "Permits";

(4) 40 C.F.R. 96.150 to 96.157 (Subpart FF), "CAIR NOx Allowance Tracking System";

(5) 40 C.F.R. 96.160 to 96.162 (Subpart GG), "CAIR NOx Allowance Transfers";

(6) 40 C.F.R. 96.170 to 96.175 (Subpart HH), "Monitoring and Reporting"; and

(7) 40 C.F.R. 96.180 to 96.188 (Subpart II), "Cair Nox Opt-in Units".

Section 3. Methodology for the Allocation and Sale of CAIR NOx Annual Allowances. The number of CAIR NOx allowances to be allocated to each CAIR NOx unit by the cabinet and to be sold by the Commonwealth of Kentucky shall be determined pursuant to this section.

(1) The total number of CAIR NOx allowances shall be:

(a) For the 2009 through 2014 control periods, 83,205 tons, as specified in 40 C.F.R. 96.140; and

(b) For the 2015 control periods and thereafter, 69,337 tons, as specified in 40 C.F.R. 96.140.

(2) The total number of CAIR NOx allowances assigned to Kentucky shall be divided into separate pools as follows:

(a) Ninety-eight (98) percent of this amount allocated for each control period to units that commence commercial operation before:

1. January 1, 2006, for the control periods 2009, 2010, 2011, 2012, 2013, and 2014;

2. January 1, 2009, for the control period 2015; and

3. Thereafter, January 1 of the year that is six (6) years before the first year of the next control period; and

(b) Two (2) percent of this amount for each control period sold by the Commonwealth of Kentucky with the proceeds deposited into Kentucky's general fund.

(3) For each CAIR NOx unit, the baseline heat input or adjusted control period heat input in mmBtu shall be determined and shall be used to determine CAIR NOx allowances for the pool specified in subsection (2)(a) of this section as follows:

(a) For CAIR NOx units commencing operation before January 1, 2001, and

1. Operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for 2001 through 2005; or

2. For units not having operated each calendar year for a period of five (5) or more consecutive years, the baseline heat input shall be established during the next allocation period when the unit has five (5) consecutive years of operation, using the average of the three (3) highest amounts of the unit's adjusted control period heat input for the most recent five (5) consecutive years of operation;

(b) For units commencing operation on or after January 1, 2001, and operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for the most recent five (5) consecutive years of operation; or

(c) For units that have not operated each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall not be established. For purposes of allocations, the heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for the previous five (5) years of operation, the:

1. Adjusted control period heat input for a control period of not operating shall equal zero; and

2. Cabinet shall allocate CAIR NOx allowances for the unit.

(4) The adjusted control period heat input for each year shall be calculated as follows:

(a) If the unit is coal-fired during the year, the unit's control period heat input for that year shall be multiplied by 100 percent;

(b) If the unit is oil-fired during the year, the unit's control period heat input for that year shall be multiplied by sixty (60) percent; and

(c) If the unit is not subject to paragraphs (a) or (b) of this subsection, the unit's control period heat input for that year shall be multiplied by forty (40) percent.

(5) For a calendar year, the unit's control period heat input and the unit's status as coal-fired or oil-fired shall be determined:

(a) In accordance with 40 C.F.R. Part 75, if the unit is subject to 40 C.F.R. Part 75;

(b) By the best available data reported to the cabinet for the unit if the unit is not otherwise subject to 40 C.F.R. Part 75; or

(c) By the best available data obtained by the cabinet.

(6) For CAIR NOx units included in the pool specified in subsection (2)(a) of this section, the cabinet shall allocate CAIR NOx allowances to each CAIR NOx unit in an amount equal to the result obtained by:

(a) Multiplying the total amount of CAIR NOx allowances specified in subsection (2)(a) of this section by the baseline heat input for each unit or the heat input established under subsection (3)(c) of this section;

(b) Dividing by the total amount of baseline heat input and the heat input established under subsection (3)(c) of this section for all applicable CAIR NOx units; and

(c) Rounding to the nearest whole CAIR NOx allowance, as appropriate.

(7) The cabinet shall submit to the U.S. EPA and CAIR NOx sources the CAIR NOx allowances to be allocated and sold from the pools specified in subsection (2) of this section in a format prescribed by the U.S. EPA by:

(a) October 31, 2006, for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014;

(b) October 31, 2009, for control period 2015; and

(c) October 31 of each year thereafter, for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

Section 4. Compliance Supplement Pool. The CAIR designated representative may request early reduction credits and the allocation of CAIR NOx

allowances from the compliance supplement pool established under 40 C.F.R. 96.143(a) for any CAIR NOx unit in the Commonwealth that achieves emission reductions in 2007 or 2008 or in both years when compared to the unit's NOx emission rate during the 2005 control period. Only emission reductions achieved in 2007 or 2008 or in both years that are not necessary to comply with any state or federal emissions limitation applicable during 2007 and 2008 may be used to request early reduction credits as specified in this section.

(1) The owners and operators of the CAIR NOx unit shall monitor and report the NOx emissions rate and the heat input of the unit in accordance with 40 C.F.R. 96.170 to 96.175 in each control period for which the early reduction is requested and for the 2005 control period. The difference resulting from subtracting the applicable 2007 or 2008 control period NOx emission rate from the 2005 control period NOx emission rate multiplied by the applicable 2007 or 2008 control period heat input divided by 2000, shall provide the amount in tons of the early reduction credit request.

(2) The CAIR designated representative shall submit to the cabinet by July 1, 2009, a request for allocation of an amount of CAIR NOx allowances from the compliance supplement pool:

(a) Not exceeding the sum of the amounts, in tons, of the unit's NOx emission reductions in 2007 and 2008 that are not necessary to comply with any state or federal emissions limitation applicable during the years, determined in accordance with 40 C.F.R. 96.170 to 96.175; or

(b) Not exceeding the minimum amount of CAIR NOx allowances necessary to remove undue risk to the reliability of electricity supply.

(3) To request allocations pursuant to subsection (2)(b) of this section, the CAIR designated representative shall demonstrate that, in the absence of allocation of an amount of CAIR NOx allowances requested, the unit's compliance with CAIR NOx emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during the control period. This demonstration shall include a showing that the owners and operators cannot feasibly obtain a sufficient amount of:

(a) Electricity from other electricity generating facilities during the installation of control technology at the unit for compliance with the CAIR NOx emissions limitation to prevent undue risk; or

(b) CAIR NOx allowances in accordance with this section, or otherwise, to prevent undue risk.

(4) Early reduction credits shall be rounded to the nearest whole number and distributed in the form of one (1) NOx allowance for one (1) ton of NOx emission reduction.

(5) The cabinet shall distribute the early reduction credits on a proportional basis.

(a) The total amount of early reduction credit available to a CAIR NOx unit shall be determined by the following calculation:

1. The unit's baseline heat input determined in Section 3(3)(a)1 of this administrative regulation;
2. Divided by the total amount baseline heat input from all sources pursuant to Section 3(3)(a)1 of this administrative regulation; and
3. Multiplied by the early reduction credits available pursuant to 40 C.F.R. 96.143(a).

(b) The unused early reduction credits shall be combined together and distributed pro rata to those CAIR NOx units with early reduction credits that exceeded the amount of credits made available by the cabinet pursuant to paragraph (a) of this subsection by the following calculation:

1. The applicable unit's emission reductions that exceeded the credits made available pursuant to paragraph (a) of this subsection;
2. Divided by the total NOx emission reductions that exceeded the credits provided under paragraph (a) of this subsection from all applicable units;
3. Multiplied by the total number of unused early reduction credits.

(c) Early reduction credits provided under paragraph (b) of this subsection shall not cause the early reduction credits allocated to the source to exceed the number of early reduction credits requested.

(6) By November 30, 2009, the cabinet shall determine and submit to the U.S. EPA the allocations under this section.

(7) By January 1, 2010, the U.S. EPA shall record the allocations submitted under subsection (6) of this section.

Section 5. Sale of CAIR NOx Allowances by the Commonwealth of Kentucky. (1) The Commonwealth of Kentucky shall establish an account pursuant to 40 C.F.R. 96.151(b) for the purpose of selling the CAIR NOx allowances in the pool specified in Section 3(2)(b) of this administrative regulation.

(2) The proceeds from the sale of the CAIR NOx allowances shall be deposited in the general fund of the Commonwealth of Kentucky. (33 Ky.R. 1015; Am. 1611; 1798; eff. 2-2-2007.)

401 KAR 51:220. CAIR NOx ozone season trading program.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121, 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

STATUTORY AUTHORITY: KRS 224.10-100(5), 42 U.S.C. 7410

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100(5) authorizes the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation establishes requirements for the control of nitrogen oxides (NOx) emissions from large boilers and turbines used in power plants and other industrial applications, pursuant to the federal mandate published under the Clean Air Interstate Rule (CAIR), 40 C.F.R. 96.301 to 96.388. This administrative regulation is not more stringent than the provisions allowed under the federal mandate.

Section 1. Applicability. This administrative regulation shall apply to:

(1) CAIR NOx Ozone Season units in Kentucky subject to 40 C.F.R. 96.304;

(2) A new or existing industrial boiler or turbine; or

(3) A new or existing electric generating unit including a fossil fuel-fired boiler, combustion turbine, or combined cycle system:

(a) Serving a generator with a nameplate capacity greater than twenty-five (25) megawatts of electricity; and

(b) Offering some electricity for sale..

Section 2. Compliance Requirements. CAIR NOx Ozone Season units shall comply with the following requirements:

(1) 40 C.F.R. 96.301 to 96.308 (Subpart AAAA), "CAIR NOx Ozone Season Trading Program General Provisions";

(2) 40 C.F.R. 96.310 to 96.315 (Subpart BBBB), "CAIR Designated Representative for CAIR NOx Ozone Season Sources";

(3) 40 C.F.R. 96.320 to 96.324 (Subpart CCCC), "Permits";

(4) 40 C.F.R. 96.350 to 96.357 (Subpart FFFF), "CAIR NOx Ozone Season Allowance Tracking System";

(5) 40 C.F.R. 96.360 to 96.362 (Subpart GGGG), "CAIR NOx Ozone Season Allowance Transfers";

(6) 40 C.F.R. 96.370 to 96.375 (Subpart HHHH), "Monitoring and Reporting"; and

(7) 40 C.F.R. 96.380 to 96.388 (Subpart IIII), "CAIR NOx Ozone Season Opt-in Units".

Section 3. Methodology for the Allocation of CAIR NOx Ozone Season Allowances. The number of CAIR NOx Ozone Season allowances to be allocated to each CAIR NOx Ozone Season unit by the cabinet and to be sold by the Commonwealth of Kentucky shall be determined pursuant to this section.

(1) The total number of CAIR NOx Ozone Season allowances shall be as follows:

(a) For the 2009 through 2014 control periods, 36,109 tons, which includes 36,045 tons as specified in 40 C.F.R. 96.340, and sixty-four (64) allowances previously allocated under 401 KAR 51:160 for units specified in Section 1(2) of this administrative regulation; and

(b) For the 2015 control periods and thereafter, 30,651 tons, which includes 30,587 tons as specified in 40 C.F.R. 96.340 and sixty-four (64) allowances previously allocated under 401 KAR 51:160 for units specified in Section 1(2) of this administrative regulation.

(2) The total number of CAIR NOx Ozone Season allowances assigned to Kentucky shall be divided into separate pools as follows:

(a) Ninety-eight (98) percent of the total number of allowances shall be allocated for each control period to units that commence operation or commence commercial operation before:

1. January 1, 2006, for the control periods 2009, 2010, 2011, 2012, 2013, and 2014;

2. January 1, 2009, for the 2015 control period; and

3. Thereafter, before January 1 of the year that is six (6) years before the next control period; and

(b) Two (2) percent of the total number of allowances for each control period shall be sold by the Commonwealth of Kentucky in accordance with Section 4 of this administrative regulation.

(3) For each CAIR NOx Ozone Season unit, the baseline heat input or adjusted control period heat input in mmBtu shall be determined and shall be used to determine CAIR NOx Ozone Season allowances for the pool specified in subsection (2) of this section as follows:

(a) For CAIR NOx Ozone Season units commencing operation or commencing commercial operation before January 1, 2001, and:

1. Operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for 2001 through 2005;or

2. For units not having operated each calendar year for a period of five (5) or more consecutive years, the baseline heat input shall be established during the next allocation period after the unit has five (5) consecutive years of operation, using the average of the three (3) highest amounts of the unit's adjusted control period heat input for the most recent five (5) consecutive years of operation;

(b) For CAIR NOx Ozone Season units commencing operation or commencing commercial operation on or after January 1, 2001, and operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input over the most recent consecutive five (5) years of operation; or

(c) For CAIR NOx Ozone Season units that have not operated each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall not be established. For purposes of allocations, the heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for the previous five (5) years of operation, the:

1. Adjusted control period heat input for a control period of not operating shall equal zero; and

2. Cabinet shall allocate CAIR NOx Ozone Season allowances for the unit.

(4) The adjusted control period heat input for each ozone season shall be calculated for CAIR NOx Ozone Season units specified in subsection (2)(a) of this section as follows:

(a) If the unit is coal-fired during the year, the unit's control period heat input for that year shall be multiplied by 100 percent;

(b) If the unit is oil-fired during the year, the unit's control period heat input for that year shall be multiplied by sixty (60) percent; and

(c) If the unit is not subject to paragraphs (a) or (b) of this subsection, the unit's control period heat input for that year shall be multiplied by forty (40) percent.

(5) The adjusted control period heat input for CAIR NOx Ozone Season units specified in subsection (2)(b) of this section shall equal the unit's control period heat input multiplied by 100 percent.

(6) For an ozone season, the unit's control period heat input and the unit's status as coal-fired or oil-fired shall be determined:

(a) In accordance with 40 C.F.R. Part 75, if the unit is subject to 40 C.F.R. Part 75;

(b) By the best available data reported to the cabinet for the unit if the unit is not otherwise subject to 40 C.F.R. Part 75; or

(c) By the best available data obtained by the cabinet.

(7) For CAIR NOx Ozone Season units included in the pool specified in subsection (2)(a) of this section, the cabinet shall allocate CAIR NOx Ozone Season allowances to each CAIR NOx Ozone Season unit in an amount equal to the result obtained by:

(a) Multiplying the total amount of CAIR NOx Ozone Season allowances specified in subsection (2)(a) of this section by the baseline heat input for each unit or the heat input established under subsection (3)(c) of this section;

(b) Dividing by the total amount of baseline heat input and the heat input established under subsection (3)(c) of this section for all applicable CAIR NOx Ozone Season units; and

(c) Rounding to the nearest whole CAIR NOx Ozone Season allowance, as appropriate.

(8) The cabinet shall submit to the U.S. EPA the CAIR NOx Ozone Season allowances to be allocated and sold from the pools specified in subsection (2) of this section in a format prescribed by the U.S. EPA by:

(a) October 31, 2006, for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014;

(b) October 31, 2009, for the control period 2015; and

(c) October 31 of each year thereafter, for the control period in the sixth year after the year of the applicable deadline for submission.

Section 4. Sale of CAIR NOx Allowances by the Commonwealth of Kentucky.

(1) The Commonwealth of Kentucky shall establish an account pursuant to 40 C.F.R. 96.351(b) for the purpose of selling the CAIR NOx Ozone Season allowances in the pool specified in Section 3(2)(b) of this administrative regulation.

(2) The proceeds from the sale of the CAIR NOx Ozone Season allowances shall be deposited in the general fund of the Commonwealth of Kentucky. (33 Ky.R. 1018; Am. 1614; 1799; eff. 2-2-2007; 3036; 4159; eff. 6-13-2007.)

401 KAR 51:230. CAIR SO_2 trading program.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.124, 51.125, 73, 74, 77, 78, Part 96, 42 U.S.C. 7410
STATUTORY AUTHORITY: KRS 224.10-100(5), 42 U.S.C. 7410
NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100(5) requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation establishes the provisions of the CAIR SO_2 Trading Program as codified at 40 C.F.R. 96.201 to 96.288 for applicable sources located in the Commonwealth of Kentucky.

Section 1. Applicability. This administrative regulation shall apply to CAIR SO_2 sources and CAIR SO_2 units under the CAIR SO_2 Trading Program located in Kentucky that are subject to 40 C.F.R. 96.204.

Section 2. Compliance requirements. CAIR SO_2 sources and CAIR SO_2 units shall comply with the following requirements:

(1) 40 C.F.R. 96.201 to 96.208 (Subpart AAA), "CAIR SO_2 Trading Program General Provisions";

(2) 40 C.F.R. 96.210 to 96.215 (Subpart BBB), "CAIR Designated Representative for CAIR SO_2 Sources";

(3) 40 C.F.R. 96.220 to 96.224 (Subpart CCC), "Permits";

(4) 40 C.F.R. 96.250 to 96.257 (Subpart FFF), "CAIR SO_2 Allowance Tracking System";

(5) 40 C.F.R. 96.260 to 96.262 (Subpart GGG), "CAIR SO_2 Allowance Transfers";

(6) 40 C.F.R. 96.270 to 96.275 (Subpart HHH), "Monitoring and Reporting"; and

(7) 40 C.F.R. 96.280 to 96.288 (Subpart III), "CAIR SO_2 Opt-in Units". (33 Ky.R. 1020; Am. 1617; eff. 2-2-2007.)

401 KAR 51:150. NOx requirements for stationary internal combustion engines.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121, 51.122, 40 C.F.R. 78, 97, 42 U.S.C. 7401-7671q
STATUTORY AUTHORITY: KRS 224.10-100(5), 224.20-110, 42 U.S.C. 7410
NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100(5) requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. 42 U.S.C. 7410 requires each state to promulgate a plan which provides for implementation, maintenance, and enforcement of the national primary and secondary ambient air quality standard in each air quality control region within the state. Pursuant to the federal NOx SIP Call, this administrative regulation provides for the regional control of nitrogen oxides (NOx) emissions by establishing requirements for large stationary internal combustion engines. This administrative regulation is not more stringent than the federal mandate.

Section 1. Definitions. (1) "Affected engine" means any stationary internal combustion engine or turbine that is:
(a) A Large NOx SIP Call Engine; or
(b) Another stationary internal combustion engine or turbine that is subject to NOx control under a compliance plan pursuant to this administrative regulation.
(2) "Facility seasonal NOx 2007 tonnage reduction" means the total of the engine seasonal NOx 2007 tonnage reductions attributable to all large NOx SIP Call Engines of an owner or operator.
(3) "Large NOx SIP Call Engine" means a stationary internal combustion engine identified and designated in the NOx SIP Call Engine inventory as emitting more than one (1) ton of NOx per average ozone season day in 1997.
(4) "NOx potential to emit" means the maximum capacity of an engine to emit NOx under its physical and operational design or applicable permit condition for a given period of time. Any physical limitation on the capacity of a source's potential to emit an air pollutant, including air pollution control equipment or combustion modification, shall be treated as part of its design if the limitation is enforceable by the cabinet.
(5) "NOx SIP Call baseline period" or "baseline period" means the period beginning May 1, 1997, and ending September 30, 1997, inclusive.
(6) "NOx SIP Call baseline period utilization" means the amount of work performed by a NOx SIP Call Engine during the baseline period in brake horsepower-hours (bhp-hr).
(7) "NOx SIP Call Engine inventory" means the NOx emission inventory, compiled by the U.S. EPA, that includes:
(a) Technical amendments pursuant to 65 Fed. Reg. 11222, March 2, 2000; and
(b) The adjustment of the 2007 budget NOx control efficiency to eighty-two (82) percent for large gas-fired engines pursuant to 69 Fed. Reg. 21603, April 21, 2004.
(8) "Past NOx emission rate" means the emission rate of an affected engine in grams per brake horsepower-hour (g/bhp-hr), as determined by performance testing consistent with the requirements of 40 C.F.R. Part 60, Appendix A. If the performance test data are not available, the rate means:
(a) The uncontrolled emission rate for Large NOx SIP Call Engines; or
(b) A rate determined by the cabinet on a case-by-case basis, using appropriate emission factors or data from the NOx SIP Call Engine inventory.
(9) "Projected 2007 NOx tonnage reduction" means the projected NOx reduction in tons during the 2007 control period, calculated as the difference between the 2007 base emissions and the 2007 budget emissions. The Projected 2007 NOx tonnage reduction may be corrected through an approved SIP revision.
(10) "Projected 2007 seasonal base NOx emissions" or "2007 base emissions" means the projected uncontrolled NOx emissions, in tons, for the 2007 control period as published in the NOx SIP Call Inventory. The 2007 base emissions may be recalculated through an approved SIP revision.
(11) "Projected 2007 seasonal budget NOx emissions" or "2007 budget emissions" means the projected controlled NOx emissions in tons, for the 2007 control period as published in the NOx SIP Call Inventory. The 2007 budget emissions may be recalculated through an approved SIP revision.
(12) "Projected 2007 Ozone Season utilization" or "2007 utilization" means the projected amount of work during the 2007 control period performed by a NOx SIP Call Engine, calculated as the 1997 baseline utilization multiplied by the growth factor assigned to that engine in the NOx SIP Call Inventory.
(13) "Projected NOx emission rate" means the projected emission rate in grams per brake horsepower-hour after installation of controls on an affected engine or the past NOx emission rate if controls are not installed on an affected engine.
(14) "Projected operating hours" means the projected actual number of hours of operation per ozone season for an affected engine.
(15) "Projected brake horsepower hours" means the projected actual number of brake horsepower hours per ozone season for an affected engine.
(16) "Stationary internal combustion engine" means any internal combustion engine of the reciprocating type that is either attached to a foundation at a facility or is designed to be capable of being carried or moved from one location to another and remains at a single site at a building, structure, facility, or installation for more than twelve (12) consecutive months. Any engine or engines that replace an engine at a site that is intended to perform the same or similar function as the engine replaced shall be included in calculating the consecutive time period.

Section 2. Applicability. This administrative regulation shall apply to the owner or operator of any large NOx SIP call engine.

Section 3. Standard for Large NOx SIP Call Engines. On and after May 1, 2007, an owner or operator of an affected engine shall not operate the engine during a control period unless:
(1) The NOx emission rate for a Large NOx SIP Call Engine is reduced from the Past NOx emission rate by at least eighty-two (82) percent; or
(2) The owner or operator complies with the requirements in Section 4 of this administrative regulation.

Section 4. Compliance Plan. On and after May 1, 2007, an owner or operator shall not operate a Large NOx SIP Call Engine during the control period unless the owner or operator complies with the requirements of a compliance plan or reduces NOx emissions from that engine in accordance with Section 3(1) of this administrative regulation.
(1) The compliance plan shall:
(a) Be approved by the cabinet in accordance with Sections 4 through 8 of this administrative regulation;
(b) Include all affected engines at an individual facility, several facilities, or at all facilities located in Kentucky that are under the control of the same owner or operator;
(c) Be submitted to the cabinet by May 1, 2006;
(d) Include credit for decreases in NOx emissions from Large NOx SIP Call Engines in Kentucky due to NOx control equipment. The owner or operator shall also include credit for decreases in NOx emissions from other affected engines in Kentucky due to NOx control equipment that is not reflected in the 2007 Ozone Season Base NOx Emissions in the NOx SIP Call Engine Inventory;
(e) Include credit for decreases in NOx emissions due to reductions from shifting historic load capacity from an uncontrolled engine to a controlled engine, electric motor, or turbine. The owner or operator shall demonstrate to the satisfaction of the cabinet that a quantifiable net reduction in NOx emissions has occurred or will occur due to a direct shift of ozone season load capacity from an uncontrolled engine to a controlled engine, electric motor, or turbine; and
(f) Provide the following information for each affected engine:

1. A list of affected engines subject to the plan that includes:
a. Engine manufacturer;
b. Engine model number;
c. Facility location address; and
d. Facility identification number.
2. The projected ozone season hours of operation and supporting documentation;
3. A description of the NOx emissions control installed, or to be installed, and documentation to support the Projected NOx Emission Rates;
4. The Past and Projected NOx Emission Rates in grams per brake horsepower-hour;
5. A numerical demonstration that the emission reductions obtained from all affected engines included in the compliance plan will be equivalent to or greater than the owner or operator's Facility Seasonal NOx 2007 Tonnage Reduction, based on the difference between the Past NOx Emission Rate and the Projected NOx Emission Rate, multiplied by the Projected brake horsepower hours for each affected engine, and considering credit according to subsection (1)(d) and (e) of this section; and
6. Provisions for monitoring, reporting, and recordkeeping.
(2) The Projected NOx Emission Rate in grams per brake horsepower-hour for each affected engine shall be included in a federally-enforceable permit.

Section 5. Compliance Demonstration. (1) Pursuant to the compliance plan required in Section 4, NOx emission reductions shall be calculated according to the following criteria:
(a) For an affected engine to which a control device is added, a combustion modification is made, or for reductions achieved pursuant to Section 4(1)(e) of this administrative regulation after September 30, 1997, the NOx emission reductions shall equal the difference between the past NOx emission rate and the projected NOx emission rate, multiplied by the Projected brake horsepower hours during the control period.
(b) For an affected engine that is removed from service after September 30, 1997, and the facility's operating capacity, in brake horsepower-hours, equivalent to the removed affected engine's projected utilization is replaced, in part or in total, during a control period:
1. By a NOx emitting device installed after September 30, 1997, the NOx emission reductions shall be the difference, in tons, between the removed affected engine's projected 2007 base emissions and the replacement device's seasonal potential to emit for the operating capacity, in brake horsepower-hours, equivalent to the portion of the removed affected engine's projected utilization that the device will replace, not to exceed 100 percent;
2. By a device that does not emit NOx installed after September 30, 1997, the NOx emission reductions shall be the removed affected engine's projected 2007 base emissions, multiplied by the percentage projected from utilization of the replacement device, not to exceed 100 percent; or
3. By a device that does not emit NOx, and a NOx emitting device is installed at the removed affected engine's facility after the date that the device that does not emit NOx was installed, the NOx emission reductions shall be the difference, in tons, between the removed affected engine's projected 2007 base emissions, and the NOx emitting device's seasonal potential to emit for its operating capacity, in tons, equivalent to the portion of the removed affected engine's projected utilization that it will replace, not to exceed 100 percent.
(2) The following shall not be considered NOx emission reductions for compliance with this administrative regulation:
(a) A restriction on an affected engine's hours of operation during a control period, including a prohibition from operating;
(b) A NOx emission limitation enforceable by the cabinet placed upon an affected engine to which no control device was added, combustion modification made or for reductions achieved pursuant to Section 4(1)(e) after September 30, 1997;
(c) The removal of an affected engine from service if that affected engine is placed into service at another location within Kentucky; or
(d) NOx emission reductions achieved at a facility that is not owned or operated by the person responsible for demonstrating compliance with this administrative regulation.
(3) Demonstrability and enforceability of NOx emission reductions.
NOx emission reductions, calculated in accordance with subsection (1)(a) or (b) of this section, shall be demonstrable and enforceable if:
(a) An hourly NOx emission limitation unit, grams per brake horsepower-hours, is included in a permit enforceable by the cabinet for the affected engine or replacement device that is to be operated during a control period;
(b) The hourly NOx emission limitation is equal to the hourly emission rate used to calculate the NOx potential to emit for the affected engine or replacement device in the compliance plan; and
(c) A performance test conducted in accordance with Section 6 of this administrative regulation determines that the affected engine or the replacement device is capable of complying with the hourly NOx emission limitation.
(4) NOx emission reductions achieved to comply with this administrative regulation shall not be considered creditable for compliance with any other applicable requirement and shall not be considered a contemporaneous emission decrease for the purposes of netting or offsets.

Section 6. Monitoring Requirements. An owner or operator of an affected engine shall:
(1) Complete an initial performance test according to the requirements codified in Appendix A to 40 C.F.R. Part 60, following the installation of emission controls required to achieve the emissions limit in Section 3(1) of this administrative regulation.
(2) Perform periodic monitoring to yield reliable data from the relevant time period that is representative of a source's compliance with the emissions limit in Section 3(1) of this administrative regulation. Periodic monitoring shall include either:
(a) Performance tests consistent with the requirements of Appendix A to 40 C.F.R. Part 60, or portable monitors using ASTM D6522-00,;
(b) A parametric monitoring program that specifies operating parameters and their ranges that will provide that each affected engine's emissions are consistent with the provisions of Section 3 of this administrative regulation;
(c) A predictive emissions measurement system that relies on automated data collection from instruments; or
(d) A continuous emission monitoring system that complies with 40 C.F.R. Part 60 or Part 75.

Section 7. Recordkeeping Requirements. An owner or operator subject to this administrative regulation shall:
(1) Maintain all records necessary to demonstrate compliance with the provisions of this administrative regulation for a period of two (2) calendar years where the affected engine is located, and provide the records, upon request, to the cabinet and the U.S. EPA;
(2) Maintain the following records for each affected engine:
(a) Identification and location of each affected engine;
(b) Calendar date of record;
(c) Number of hours the affected engine is operated during each control period compared to the Projected Operating Hours;
(d) Type and quantity of fuel used; and
(e) Results of all compliance tests.

Section 8. Reporting Requirements. An owner or operator subject to the provisions of this administrative regulation shall submit the required reports, compliance plans, and compliance test results to:
(1) Manager, Permit Review Branch, Kentucky Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky 40601, (502) 573-3382; and

(2) The appropriate Regional Office of the Division for Air Quality as follows:
(a) Ashland Regional Office, 1550 Wolohan Drive, Suite 1, Ashland, Kentucky 41102, (606) 929-5285;
(b) Bowling Green Regional Office, 1508 Westen Avenue, Bowling Green, Kentucky 42104, (270) 746-7475;
(c) Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, Kentucky 41042, (859) 525-4923;
(d) Hazard Regional Office, 233 Birch Street, Suite 2, Hazard, Kentucky 41701, (606) 435-6022;
(e) London Regional Office, 875 South Main Street, London, Kentucky 40741, (606) 878-0157;
(f) Owensboro Regional Office, 3032 Alvey Park Drive, W., Suite 700, Owensboro, Kentucky 42303, (270) 687-7304; or
(g) Paducah Regional Office, 130 Eagle Nest Drive, Paducah, Kentucky 42003, (270) 898-8468.

Section 9. Incorporation by Reference. (1) "ASTM D6522-00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and process Heaters Using Portable Analyzers, Book of ASTM Standards, February 10, 2000 and April 2000," is incorporated by reference.

(2) This material may be inspected, copied, or obtained, subject to applicable copyright law, at the Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky 40601, (502) 573-3382, Monday through Friday, 8 a.m. to 4:30 p.m.

(3) Copies are available for sale from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania, 19428-2959, telephone (610) 832-9585, facsimile (610) 832-9555, and the Internet http://www.astm.org/. (32 Ky.R. 793; 1123; 1231; eff. 2-3-2006.)

401 KAR 51:160. NOx requirements for large utility and industrial boilers.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121, 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

STATUTORY AUTHORITY: KRS 224.10-100(5), 224.20-110, 40 C.F.R. 51.121, 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100(5) requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. 42 U.S.C. 7410 requires each state to promulgate a plan which provides for implementation, maintenance, and enforcement of the national primary and secondary ambient air quality standard in each air quality control region within the state. This administrative regulation establishes requirements for the control of nitrogen oxides (NOx) emissions from large boilers and turbines used in power plants and other industrial applications, pursuant to the federal mandate published under the NOx SIP Call. This administrative regulation is not more stringent nor otherwise different than the provisions allowed under the federal mandate.

Section 1. Applicability. This administrative regulation shall apply to NOx budget units that are electric generating units or industrial boilers or turbines, except as provided in Section 2 of this administrative regulation.

Section 2. Exemptions. (1) Exemptions based on permit limitations. A NOx budget unit shall be exempt from Sections 3 to 7 of this administrative regulation if the owner or operator complies with this subsection.

(a) The source shall have a federally-enforceable permit issued by the cabinet containing conditions for the unit that:

1. Limit the unit’s NOx emissions during each control period beginning in 2004 to twenty-five (25) tons or less;

2. Restrict the unit to burning only natural gas or fuel oil during a control period in 2004 and each control period thereafter;

3. Restrict the unit's operation hours during each control period to the number calculated by dividing twenty-five (25) tons of potential NOx mass emissions by the unit's maximum potential hourly NOx mass emissions;

4. Require that the unit's potential NOx mass emissions shall be calculated pursuant to 40 C.F.R. 96.4(b)(1)(iii);

5. Require that the owner or operator of the unit shall retain at the source that includes the unit, for five (5) years, records demonstrating that the operating hours restriction, the fuel use restriction, and the other requirements of the permit related to these restrictions were met; and

6. Require that, by November 1 of each year for which the unit is subject to the federally-enforceable permit, the owner or operator of the unit, through the authorized account representative, shall:

a. Secure and transfer to an account established pursuant to 401 KAR 51:190, NOx allowances for each control period in an amount equal to the NOx emission limitation (in tons of NOx) under subparagraphs 1 and 3 of this paragraph upon which the unit's exemption is based; and

b. Report to the cabinet the unit's hours of operation (treating any partial hour of operation as a whole hour of operation) and the number of NOx allowances transferred pursuant to clause a of this subparagraph.

(b) A unit with an exemption based on permit limitations shall become subject to all the applicable provisions of this administrative regulation and shall be treated as commencing commercial operation on September 30 of any control period for which:

1. The fuel use restriction in paragraph (a)2 of this subsection or the operating hours restriction in paragraph (a)3 of this subsection is removed from the unit's federally-enforceable permit or otherwise becomes no longer applicable; or

2. The unit does not comply with the restrictions of this subsection.

(c) Units exempted under this subsection shall not receive a NOx allowance allocation under Section 4 of this administrative regulation.

(d) By November 30 of each year beginning in 2004, the cabinet shall report to the U.S. EPA:

1. The total NOx emission limitation (in tons of NOx) for all units exempted under this subsection; and

2. The total NOx allowances reported to the cabinet pursuant to paragraph (a)6b of this subsection.

(e) For units exempted under this subsection, the cabinet shall notify the U.S. EPA, in writing:

1. Of permit changes that remove a limit or render it no longer applicable; and

2. Any violation of a permit limit imposed pursuant to paragraph (a) of this subsection.

(2) Retired unit exemption.

(a) A NOx budget unit shall be exempt from the requirements in Sections 3 to 7 of this administrative regulation on the date that the unit is permanently retired, if the following conditions are met:

1. Except as provided in paragraph (b) of this subsection, the retired unit shall not emit NOx on or after the day it is retired; and

2. Within thirty (30) days after the unit is retired, the NOx authorized account representative shall submit:

a. A letter to the cabinet and to the U.S. EPA describing the unit, the date of retirement, and the reason for retirement; and

b. An application for a permit revision that reflects the status of the retired unit pursuant to 401 KAR 52:020 or 401 KAR 52:030, as appropriate; and

3. Unless the unit has been physically removed, records to demonstrate that the unit has not been operated shall be:

a. Maintained on-site for five (5) years from the date of retirement; and

b. Made available to the cabinet or the U.S. EPA upon request.

(b) Operation of a retired unit shall not be resumed unless the owner or operator submits an application and receives a permit revision pursuant to 401 KAR 52:020 or 401 KAR 52:030, as appropriate, prior to commencing operation.

(c) A retired unit shall not be allowed to opt into 401 KAR 51:190, Banking and trading NOx allowances and shall not receive a NOx allowance allocation under Section 4 of this administrative regulation.

(d) NOx allowances made to a unit that later retires shall:

1. Remain with the unit until they are transferred or deducted; and

2. Cease to be allocated to the unit at the end of the allocation period.

(e) The cabinet shall notify the U.S. EPA, in writing, of units that are exempted under this subsection.

(3) Category exemption. A carbon monoxide boiler that is associated with fluidized catalytic cracking units (FCCU) at petroleum refineries shall be exempt from the requirements in Sections 3 to 7 of this administrative regulation.

Section 3. Compliance Requirements. (1) NOx budget emissions limitation requirements. Commencing with the later date of May 31, 2004, or the year the unit commences operation, the owner or operator of a NOx budget unit shall:

(a) Beginning May 1, 2003, and May 1 of each year thereafter, monitor the total NOx emissions during each control period as specified in 40 C.F.R. 96.70 to 96.76; and

(b) By November 30 of each year, hold NOx allowances available for compliance deductions in an amount at least equal to the total NOx emissions during the control period as specified in 401 KAR 51:190.

(2) NOx allowance provisions. NOx allowances shall be held in, deducted from, or transferred among the NOx compliance, overdraft, and general accounts as specified in 401 KAR 51:190 and this subsection.

(a) The NOx budget source shall establish a general account in the NOx allowance Tracking System (NATS) by submitting "EPA Form 7620-15,

General Account information".

(b) NOx budget units shall transfer NOx allowances under the NOx Budget Trading Program from one (1) account to another in the NOx Allowance Tracking System (NATS) by submitting "EPA Form 7620-14".

(c) NOx allowances shall not be deducted for compliance with subsection (1) of this section for a control period prior to the year for which the NOx allowances were allocated.

(d) If the U.S. EPA records the allocation, transfer, or deduction of NOx allowances from the compliance or overdraft account of a NOx budget source, this action shall:

1. Automatically amend and become part of the NOx budget portion of the source's permit; and

2. Require no further review.

(e) The owner or operator of a NOx budget unit having excess NOx emissions for each control period beginning in 2004, shall comply with 401 KAR 51:190.

(f) Allocated NOx allowances shall not constitute a property right.

(3) Recordkeeping and reporting requirements.

(a) The owner or operator of a NOx budget source shall maintain the following records:

1. The "Account Certificate of Representation" for the source's NOx authorized account representative;

2. Emissions monitoring information as specified in 40 C.F.R. 96.70 to 96.76;

3. Copies of all reports, compliance certifications, and other submissions and records required by 401 KAR 51:190; and

4. Copies of documents used to complete permit revision applications or to demonstrate compliance with 401 KAR 51:190.

(b) These records shall be:

1. Used to demonstrate compliance with subsection (1) of this section;

2. Maintained on site for a period of five (5) years, unless a longer period is required by 40 C.F.R. 96.70 to 96.76 or the cabinet or the U.S. EPA requires an extended period for cause; and

3. Made available for inspection on request by the cabinet or the U.S. EPA.

(4) Computation of time.

(a) A time period scheduled to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) A time period scheduled to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) If the final day of a time period falls on a weekend or state or federal holiday, the time period shall be extended to the next business day.

Section 4. Methodology for the Allocation and Sale of NOx Allowances. The number of NOx allowances to be allocated to each NOx budget unit by the cabinet and to be sold by the Commonwealth of Kentucky shall be determined pursuant to this section.

(1) The total number of NOx allowances shall be the number of NOx allowances assigned to Kentucky by the U.S. EPA and approved in Kentucky's State Implementation Plan (SIP).

(2) The total number of NOx allowances assigned to Kentucky shall be divided into separate pools as follows:

(a) The number of NOx allowances specified in Kentucky's approved SIP for electric generating units with:

1. Ninety-five (95) percent of this amount allocated for the 2004 to 2006 allocation period to units that commence commercial operation on or before May 1, 2001;

2. Five (5) percent of this amount for the 2004 to 2006 allocation period sold by the Commonwealth of Kentucky with the proceeds deposited in Kentucky's general fund;

3. Ninety-eight (98) percent of this amount allocated for each allocation period beginning with the 2007 to 2009 allocation period to units that commence commercial operation on or before May 1 of the year that is three (3) years before the first year of the applicable allocation period; and

4. Two (2) percent of this amount for each allocation period beginning with the 2007 to 2009 allocation period and each allocation period thereafter sold by the Commonwealth of Kentucky with the proceeds deposited in Kentucky's general fund; and

(b) The number of NOx allowances specified in Kentucky's approved SIP for industrial boilers or turbines with:

1. Ninety-eight (98) percent of this amount allocated for each allocation period to units that commence commercial operation on or before May 1 of the year that is three (3) years before the first year of the applicable allocation period; and

2. Two (2) percent of this amount allocated for each allocation period to NOx budget units that commence commercial operation after May 1 of the year that is three (3) years before the first year of the applicable allocation period and on or before May 1 of the applicable control period.

(3) The cabinet shall notify the U.S. EPA and NOx budget sources of the NOx allowances to be allocated and sold from the pools specified in subsection (2) of this section pursuant to Section 5(4) of this administrative regulation.

(4) For allocation of the pools specified in subsection (2)(a)1, 3 and (b) of this section, heat input, in MMBTU, of a NOx budget unit shall be determined from:

(a) The average of the two (2) highest amounts of the unit's heat input from the three (3) most recent control periods as determined in accordance with 40 C.F.R. Part 75 or 96.70 to 96.76 if the unit is subject to 40 C.F.R. Part 75; or

(b) The best available data reported to the cabinet for the unit if the unit is not otherwise subject to 40 C.F.R. Part 75.

(5) For electric generating units included in the pools specified in subsection (2)(a)1 and 3 of this section, the cabinet shall allocate NOx allowances to each NOx budget unit in an amount equal to the result obtained by:

(a) Multiplying 0.15 lb/MMBTU or the permit limit, whichever is less, by the heat input determined under Section 4(4) of this administrative regulation, rounded to the nearest whole NOx allowance as appropriate.

(b) If the initial total number of NOx allowances allocated for an allocation period to all NOx budget units in Kentucky included in the pools specified in subsection (2)(a)1 and 3 of this section does not equal ninety-five (95) percent for the 2004 to 2006 allocation period, or ninety-eight (98) percent for each allocation period thereafter, of the number of tons of NOx emissions in Kentucky's trading program budget apportioned to existing electric generating units, the cabinet shall:

1. Adjust the total number of NOx allowances allocated to all electric generating units in the applicable pool so that the total number of NOx allowances allocated equals ninety-five (95) percent for the 2004 to 2006 allocation period, or ninety-eight (98) percent for each allocation period thereafter, of the number of tons of NOx emissions in Kentucky's trading program budget apportioned to electric generating units; and

2. Make this adjustment by multiplying each unit's allocation by ninety-five (95) percent for the 2004 to 2006 allocation period, or ninety-eight (98) percent thereafter, of the number of tons of NOx emissions in Kentucky's trading program budget apportioned to electric generating units divided by the total number of NOx allowances allocated under paragraph (a) of this subsection, and rounding to the nearest whole NOx allowance as appropriate.

(6) For industrial boilers or turbines included in the pool specified in subsection (2)(b)1 of this section, the cabinet shall allocate NOx allowances to each NOx budget unit in an amount equal to the result obtained by:

(a) Multiplying 0.17 lb/MMBTU or the permit limit, whichever is less, by the heat input determined under subsection (4) of this section, rounded to the nearest whole NOx allowance as appropriate.

(b) If the initial total number of NOx allowances allocated for an allocation period to all NOx budget units in Kentucky included in the pool specified in subsection (2)(b)1 of this section does not equal ninety-eight (98) percent for each allocation period, of the number of tons of NOx emissions in Kentucky's trading program budget apportioned to existing industrial boilers or turbines, the cabinet shall:

1. Adjust the total number of NOx allowances allocated to all industrial boilers or turbines in the applicable pool so that the total number of NOx allowances allocated equals ninety-eight (98) percent for each allocation period, of the number of tons of NOx emissions in Kentucky's trading program budget apportioned to industrial boilers or turbines; and

2. Make this adjustment by multiplying each unit's allocation by ninety-eight (98) percent, of the number of tons of NOx emissions in Kentucky's trading program budget apportioned to industrial boilers or turbines divided by the total number of NOx allowances allocated under paragraph (a) of this subsection, and rounding to the nearest whole NOx allowance as appropriate.

(7)(a) The Commonwealth of Kentucky shall establish an account pursuant to 401 KAR 51:190 for the purpose of selling the NOx allowances in the pools specified in subsection (2)(a)2 and 4 of this section. The proceeds from the sale of the NOx allowances shall be deposited in the general fund of the Commonwealth of Kentucky.

(b) For NOx budget units included in the pool specified in subsection (2)(b)2 of this section, the cabinet shall allocate NOx allowances to each unit according to the following procedures:

1. The cabinet shall establish one (1) allocation set-aside for each control period. Each allocation set-aside shall be allocated NOx allowances equal to two (2) percent for each control period of the tons of NOx emissions in Kentucky's trading program budget, rounded to the nearest whole NOx allowance as appropriate.

2. The NOx authorized account representative may submit to the cabinet a request, in writing, to be allocated NOx allowances starting with the control period during which the NOx budget unit commences commercial operation, or is projected to commence commercial operation, and ending with the control period preceding the control period for which it will receive an allocation under subsection (2)(b)1 of this section. The request shall be in accordance with the following requirements:

a. The NOx allowance allocation request shall be submitted prior to May 1 of the first control period for which the NOx allowance allocation is requested and after the date on which the cabinet issues a permit to construct to the NOx budget unit; and

b. For a control period, the NOx authorized account representative may request NOx allowances in an amount that does not exceed 0.17 lb/MMBTU or the permitted limit, whichever is less, multiplied by the NOx budget unit's maximum design heat input in MMBTU/hr multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate.

3. The cabinet shall review, and allocate NOx allowances pursuant to, each NOx allowance allocation request in the order that the requests are received by the cabinet as of the close of business each day, with each consecutive day determining the order:

a. Upon receipt of the NOx allowance allocation request, the cabinet shall determine whether, and shall make any necessary adjustments to the request to ensure that the control period and the number of NOx allowances specified are consistent with the requirements of this subsection.

b. If the allocation set-aside for the control period for which NOx allowances are requested:

(i) Has an amount of NOx allowances not less than the number requested, as adjusted by the cabinet, the cabinet shall allocate the amount of the NOx allowances requested, as adjusted by the cabinet, to the NOx budget unit.

(ii) Has a smaller amount of NOx allowances than the number requested, as adjusted by the cabinet, the cabinet will deny in part the request and allocate only the remaining number of NOx allowances in the allocation set-aside to the NOx budget unit.

(iii) Once an allocation set-aside for a control period has been depleted of all NOx allowances, the cabinet shall deny, and shall not allocate any NOx allowances pursuant to a NOx allowance allocation request under which NOx allowances have not already been allocated for the control period.

4. Within sixty (60) days of receipt of a NOx allowance allocation request, the cabinet shall take appropriate action under this subsection and shall notify the U.S. EPA of the number of NOx allowances allocated for the control period to the NOx budget unit.

5. For a NOx budget unit that is allocated NOx allowances under this subparagraph, the U.S. EPA shall deduct NOx allowances to account for the actual utilization of the unit during the control period, and for any NOx allowances returned to Kentucky, the cabinet shall allocate to the NOx budget units in Kentucky using the following formula and rounding to the nearest whole NOx allowance as appropriate:

a. Unit's share of NOx allowances remaining in allocation set-aside equals total NOx allowances remaining in allocation set-aside multiplied by the quantity generated by dividing the unit's NOx allowance allocation by Kentucky's trading program budget excluding allocation set-aside;

b. If:

(i) Total NOx allowances remaining in allocation set-aside is the total number of NOx allowances remaining in the allocation set-aside for the control period to which the allocation set-aside applies;

(ii) Unit's NOx allowance allocation is the number of NOx allowances allocated under subsection (2)(b)2 of this section to the unit for the control period to which the allocation set-aside applies; and

(iii) State trading program budget excluding allocation set-aside is Kentucky's trading program budget for the control period to which the allocation set-aside applies multiplied by ninety-five (95) percent if the control period is in 2004, 2005, or 2006 or ninety-eight (98) percent if the control period is in any year thereafter, rounded to the nearest whole NOx allowance as appropriate.

(8) NOx allowances created pursuant to 401 KAR 51:180 for early reduction credits or emergency compliance shall not be included in the allocation or sale of the pools specified in this section.

Section 5. Allocation of NOx Allowances. (1) The cabinet shall determine the number of NOx allowances to be allocated to eligible NOx budget units for the allocation period beginning in 2004 and in each subsequent allocation period using the method described in Section 4 of this administrative regulation.

(2) A NOx budget unit that commences commercial operation on or before May 1 of the year that is three (3) years before the first year of the applicable allocation period shall be included in the applicable allocation pool as specified in Section 4(2)(a)1, 3, or (b)1 of this administrative regulation.

(3) If the U.S. EPA changes the number of NOx allowances assigned to Kentucky before the end of an allocation period, the cabinet shall reallocate the NOx allowances prior to the beginning of the next control period in the same ratio as the original allocation for that period.

(4) The cabinet shall notify the U.S. EPA and NOx budget sources of the NOx allowances to be allocated and sold by the Commonwealth of Kentucky pursuant to this section and Section 4 of this administrative regulation:

(a) For units that commence commercial operation on or before May 1 of the year that is three (3) years before the first year of the applicable allocation period:

1. Not later than sixty (60) days after the effective date of this administrative regulation for the allocation period beginning in 2004; and

2. By April 1 of the year that is three (3) years prior to the next allocation period; and

(b) By April 1 of each year, beginning in 2004, for units in the pool specified in Section 4(2)(b)2 of this administrative regulation that commence commercial operation after May 1 of the year that is three (3) years before the first year of the applicable allocation period and on or before May 1 of the applicable control period.

(5) Excess NOx allowances may be banked and traded according to 401 KAR 51:190.

Section 6. Application for NOx Budget Permit or Permit Revision. (1) The NOx authorized account representative of a NOx budget source shall submit an application to revise the source's permit pursuant to 401 KAR 52:020 or 401 KAR 52:030, as appropriate, and this section. For this purpose, the source shall use:

(a) "Forms DEP7007A1 to DD, Permit Application to Construct or Operate an Air Contaminant Source," as applicable. Forms DEP7007A1 to DD is incorporated by reference in 401 KAR 52:050; and

(b) "Form DEP7007EE, NOx Budget Permit Application".
(2) The application shall include the following information:
(a) The Office of Regulatory Information Systems (ORIS) or facility code assigned to the source by the Energy Information Administration;
(b) Identification of:
1. Each NOx budget unit at the source;
2. Each retired unit; and
3. Each unit exempted pursuant to Section 2(1) of this administrative regulation;
(c) A statement that explains if the unit is:
1. A unit described in Section 1 of this administrative regulation; or
2. An opt-in unit pursuant to 401 KAR 51:195;
(d) The applicable requirements of Section 3 of this administrative regulation; and
(e) For opt-in units, the following certification statement signed by the NOx authorized account representative: "I certify that each unit for which this permit application is submitted, pursuant to the opt-in provisions of 401 KAR 51:195, is operating; is not a NOx budget unit pursuant to 401 KAR 51:160, Section 1; and is not covered by a retired exemption unit that is in effect pursuant to 401 KAR 51:160, Section 2(2)."

Section 7. Compliance. (1) Compliance certification. On or before November 30 each year, beginning in 2004, the NOx authorized account representative shall submit a compliance certification report to the cabinet and to the U.S. EPA pursuant to 401 KAR 51:190.
(2) Reporting to the cabinet. Reports that are required to be submitted to the cabinet shall be mailed to:
(a) Manager, Permit Review Branch, Kentucky Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky 40601; and
(b) To the appropriate Regional Office of the Division for Air Quality listed in Section 8(2) of this administrative regulation.

Section 8. Incorporation by Reference. (1) The following material is incorporated by reference:
(a) "Form DEP7007EE, NOx Budget Permit Application", May 2002;
(b) "EPA Form 7620-14, Allowance Transfer", United States Environmental Protection Agency, OMB No. 2060-0445;
(c) "EPA Form 7620-15, General Account Information", United States Environmental Protection Agency, OMB No. 2060-0445; and
(d) "EPA Form 7620-16, Account Certificate of Representation", United States Environmental Protection Agency, OMB No. 2060-0445.
(2) This material may be inspected, copied, or obtained, subject to applicable copyright law, at the following offices of the Division for Air Quality, Monday through Friday, 8 a.m. to 4:30 p.m.:
(a) The Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky 40601, (502) 573-3382; and
(b) The appropriate regional office of the Division for Air Quality as follows:
1. Ashland Regional Office, 1550 Wolohan Drive, Suite 1,, Ashland, Kentucky 41102, (606) 929-5285;
2. Bowling Green Regional Office, 1508 Westen Avenue, Bowling Green, Kentucky 42104, (270) 746-7475;
3. Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, Kentucky 41042, (859) 525-4923;
4. Hazard Regional Office, 233 Birch Street, Suite 2, Hazard, Kentucky 41701, (606) 435-6022;
5. London Regional Office, 875 S. Main Street, London, Kentucky 40741, (606) 330-2080;
6. Owensboro Regional Office, 3032 Alvey Park Drive, W., Suite 700, Owensboro, Kentucky 42303, (270) 687-7304; or
7. Paducah Regional Office, 130 Eagle Nest Drive, Paducah, Kentucky 42003, (270) 898-8468.
(3)(a) Copies of the Code of Federal Regulations (C.F.R.) and Federal Register (Fed. Reg.) are available for sale from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402.
(b) Copies of Forms DEP7007EE-1 to EE-3 are available on the Internet at http://www.air.ky.gov/permitting/Permit+Application+Forms.htm. (27 Ky.R. 2606; Am. 3276; 28 Ky.R. 373; eff. 8-15-2001; 29 Ky.R. 540; 1605; eff. 12-18-02; 32 Ky.R. 724; 1233; eff. 2-3-06.)

401 KAR 51:170. NOx requirements for cement kilns.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

STATUTORY AUTHORITY: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100 requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation provides for the regional control of nitrogen oxides (NOx) emissions from portland cement manufacturing plants pursuant to the federal mandate published under the NOx SIP Call. This administrative regulation is not more stringent nor otherwise different than the provisions allowed under the federal mandate.

Section 1. Applicability. This administrative regulation shall apply to a portland cement manufacturing plant with process rates, on or after January 1, 1995, equal to or greater than:

(1) Twelve (12) tons of clinker per hour for a long dry kiln;

(2) Ten (10) tons of clinker per hour for a long wet kiln;

(3) Sixteen (16) tons of clinker per hour for a preheater kiln; or

(4) Twenty-two (22) tons of clinker per hour for a precalciner or preheater/precalciner kiln.

Section 2. Standard for Kilns. (1) On and after May 31, 2004, the owner or operator of a kiln specified in Section 1 of this administrative regulation shall, during a control period, operate the kiln so that NOx emissions do not exceed six and six-tenths (6.6) lbs per ton of clinker averaged over a thirty (30) day rolling period.

(2) The requirements in subsection (1) of this section shall not apply during:

(a) Periods of start-up, shutdown, or malfunction that do not exceed thirty-six (36) consecutive hours; and

(b) Regularly scheduled maintenance activities.

Section 3. Reporting, Monitoring, and Recordkeeping for Kilns. (1) Reporting requirements. The owner or operator of a kiln specified in Section 1 of this administrative regulation shall submit the following reports to the cabinet at the locations specified in Section 4 of this administrative regulation:

(a) By May 31, 2004, a report that includes:

1. The number and types of kilns;

2. The name and address of the plant where the kilns are located; and

3. The name and telephone number of the person responsible for demonstrating that the kiln is in compliance.

(b) By October 31 each year, beginning in 2004, a report that documents the total NOx emissions from the kiln during the control period.

(2) Monitoring requirements. Beginning April 1, 2004, the owner or operator of a kiln specified in Section 1 of this administrative regulation shall monitor NOx emissions during each control period in accordance with provisions in 40 CFR 96.70 to 96.76.

(3) Recordkeeping requirements. An owner or operator of a kiln specified in Section 1 of this administrative regulation shall maintain all records necessary to demonstrate compliance with the standards in Section 2 of this administrative regulation for a period of two (2) years. These records shall:

(a) Be kept at the facility where the kiln is located;

(b) Be made available to the cabinet or the U.S. EPA upon request; and

(c) Contain the following information:

1. Emissions, in pounds of NOx per ton of clinker, from the kiln;

2. The results of all performance tests;

3. Daily production records; and

4. The date, time, and duration of all startups, shutdowns, or malfunctions in the operation of the kiln or emissions monitoring equipment.

Section 4. Reporting to the Cabinet. Reports required to be submitted to the cabinet shall be mailed to:

(1) Manager, Permit Review Branch, Kentucky Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky 40601; and

(2) To the appropriate Regional Office of the Division for Air Quality as follows:

(a) Ashland Regional Office, 3700 Thirteenth Street, Ashland, Kentucky 41105, (606) 920-2067;

(b) Bowling Green Regional Office, 1508 Westen Avenue, Bowling Green, Kentucky 42104, (270) 746-7475;

(c) Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, Kentucky 41042, (859) 525-4923;

(d) Hazard Regional Office, 233 Birch Street, Suite 2, Hazard, Kentucky 41701, (606) 435-6022;

(e) London Regional Office, 875 S. Main Street, London, Kentucky 40741, (606) 330-2080;

(f) Owensboro Regional Office, 3032 Alvey Park Drive, W., Suite 700, Owensboro, Kentucky 42303, (270) 687-7304; and

(g) Paducah Regional Office, 130 Eagle Nest Drive, Paducah, Kentucky 42003, (270) 898-8468. (27 Ky.R. 2609; Am. 3281; eff. 8-15-2001; TAm eff. 8-9-2007.)

401 KAR 51:180. NOx credits for early reduction and emergency.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

STATUTORY AUTHORITY: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100 requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation provides for the distribution of NOx allowances from a compliance supplement pool allocated to Kentucky by the U.S. EPA for sources that reduce nitrogen oxides (NOx) emissions before the compliance deadline of the federal mandate published under the NOx SIP Call. It also provides for setting aside unused credits to assist sources that are unable to meet the compliance deadline. This administrative regulation is not more stringent nor otherwise different than the provisions allowed under the federal mandate.

Section 1. Applicability. This administrative regulation shall apply to a NOx budget unit in Kentucky.

Section 2. Procurement and Use of Early Reduction Credits (ERCs). (1) ERCs may be earned for reductions in NOx emissions achieved during the 2001, 2002, and 2003 control periods.

(2) NOx allowances given for earned ERCs may be deducted for compliance with NOx emission standards in 401 KAR 51:160 only during the 2004 and 2005 control periods.

(3) ERCs shall not be earned for emission reductions made to satisfy requirements under the Clean Air Act.

Section 3. The Compliance Supplement Pool. (1) The compliance supplement pool shall be divided into separate pools (utility and industry) based on the ratio of the NOx emission reductions required from each group to the total reductions required from both groups multiplied by the number of ERCs in the compliance supplement pool as specified in the Kentucky State Implementation Plan (SIP).

(2) The utility pool shall be further divided into separate annual allocations as follows:

(a) Twenty (20) percent of the utility pool to be allocated for NOx emission reductions achieved in 2001;

(b) Thirty (30) percent of the utility pool to be allocated for NOx emission reductions achieved in 2002; and

(c) Fifty (50) percent of the utility pool to be allocated for NOx emission reductions achieved in 2003.

(3) The entire industry pool shall be available for distribution beginning in 2002 and shall be allocated annually through 2004 for NOx emission reductions achieved in 2001, 2002, and 2003 or until all available NOx allowances are allocated.

(4) Unrequested NOx allowances from the previous year shall be made available in the applicable pool for the next annual allocation.

Section 4. Methodology for Determining Allocation of ERCs. (1) The annual allocation of ERCs shall be made based on the actual NOx emission reductions achieved for each NOx budget unit during the 2001, 2002, and 2003 control periods compared to the unit’s baseline NOx emission rate during the 2000 control period.

(2) Baseline emissions shall be determined using the procedures in 40 CFR 96.70 to 96.76.

(3) ERCs shall be granted only for NOx emission reductions that are monitored pursuant to Section 6 of this administrative regulation and reported pursuant to Section 7 of this administrative regulation.

(4) An ERC shall be granted for each ton of NOx emission reduction achieved below 0.45 lbs/MMBTU or the average NOx emission rate (in lbs/MMBTU) from the baseline control period in 2000, whichever is less.

(5) ERCs shall be rounded to the nearest whole number and distributed in the form of one (1) NOx allowance for one (1) ton of NOx emission reduction.

(6) If the requests for ERCs exceeds the maximum NOx allowances available for distribution in the applicable pool for an annual allocation, the cabinet shall distribute the ERCs on a proportional basis using the following calculation: the NOx budget unit's allocated ERCs shall equal the unit's NOx emission reductions determined pursuant to subsection (3) of this section divided by the total NOx emission reductions from all units in the applicable pool multiplied by the ERCs available for distribution in that pool.

(7) NOx allowances shall be distributed annually on or before May 1 of each year for the previous year's NOx emission reductions beginning in 2002 and ending in 2004.

(8) The cabinet shall notify the U.S. EPA of the final allocation on or before May 31, 2004.

Section 5. NOx Credits for Emergency Use. After allocations are made pursuant to Section 4 of this administrative regulation for 2001, 2002, and 2003, credits that remain in the compliance supplement pools shall be used by the cabinet to assist sources that are unable to meet the compliance deadline in 401 KAR 51:160 according to the following restrictions:

(1) ERCs remaining in the utility pool shall only be used to assist electric generating units and ERCs remaining in the industry pool shall only be used to assist industrial boilers or turbines.

(2) Credits shall be issued by the cabinet to extend the compliance deadline only for sources that meet the following conditions:

(a) Electric generating units for which meeting the compliance deadline would seriously jeopardize the reliability of the electric supply, and for which it was not feasible to import electricity from other sources in order to meet the deadline;

(b) Industrial boilers and turbines for which meeting the compliance deadline would create an undue risk comparable to that for utility sources in paragraph (a) of this subsection; and

(c) Sources able to demonstrate that it was not possible to acquire sufficient NOx allowances to meet the compliance deadline by:

1. Generating ERCs;

2. Acquiring ERCs from other sources; or

3. Acquiring NOx allowances from the NOx Budget Trading Program.

(3) Allowances shall be allocated, based upon need, in 2004 and 2005.

(4) A public hearing shall take place before allowances are allocated.

Section 6. Monitoring Requirements. (1) Monitoring shall be performed on a NOx budget unit for which early reduction credit is to be obtained during the 2000 control period and each subsequent control period during which NOx emission reductions will occur.

(2) Units shall be monitored in accordance with 40 CFR 96.70 to 96.76.

Section 7. Reporting Requirements. (1) The owner or operator of a NOx budget source that achieves early reductions pursuant to this administrative

regulation shall submit a report to the cabinet on or before January 30 of each year following the year in which reductions were achieved for the years of 2001, 2002, and 2003, documenting the actual NOx emission reductions achieved by each NOx budget unit during each control period compared to the unit's actual emissions during the 2000 control period. These reports shall contain the following information, for each NOx budget unit:

(a) Identification and location of the unit that achieved NOx emission reductions;

(b) The maximum design heat input for the unit, expressed in MMBTU/hr;

(c) For the 2000 control period and each control period during which NOx emission reductions are achieved:

1. The total hours of operation;

2. The total NOx emissions, in tons;

3. The average NOx emission rate, in lbs/MMBTU;

4. The maximum allowable NOx emission rate, based on the most stringent applicable requirement, in lbs/MMBTU; and

5. Calculations showing the tons of NOx emission reductions below 0.45 lbs/MMBTU or the average NOx emission rate (in lbs/MMBTU) from the baseline season, whichever is less.

(2) The report required in subsection (1) of this section shall be signed by the owner or operator of the NOx budget source and submitted to:

(a) Manager, Permit Review Branch, Kentucky Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky 40601; and

(b) The appropriate regional office of the Division for Air Quality as follows:

1. Ashland Regional Office, 3700 Thirteenth Street, Ashland, Kentucky 41105, (606) 920-2067;

2. Bowling Green Regional Office, 1508 Westen Avenue, Bowling Green, Kentucky 42104, (270) 746-7475;

3. Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, Kentucky 41042, (859) 525-4923;

4. Hazard Regional Office, 233 Birch Street, Suite 2, Hazard, Kentucky 41701, (606) 435-6022;

5. London Regional Office, 875 S. Main Street, London, Kentucky 40741, (606) 330-2080;

6. Owensboro Regional Office, 3032 Alvey Park Drive, W., Suite 700, Owensboro, Kentucky 42303, (270) 687-7304; or

7. Paducah Regional Office, 130 Eagle Nest Drive, Paducah, Kentucky 42003, (270) 898-8468. (27 Ky.R. 2611; Am. 3283; 28 Ky.R. 377; eff. 8-15-2001; TAm eff. 8-9-2007.)

401 KAR 51:190. Banking and trading NOx allowances.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

STATUTORY AUTHORITY: KRS 224.10-100, 224.20-100, 224.20.110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100 requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation incorporates by reference the federal regulation that establishes a program for banking and trading of emission allowances to reduce nitrogen oxides (NOx) emissions under the federal NOx SIP Call. This administrative regulation is not more stringent nor otherwise different than the provisions of the federal mandate.

Section 1. For purposes of 40 CFR 96.10 to 96.14, 96.30, 96.31, 96.50 to 96.55 (b), 96.56 to 96.57, 96.60 to 96.62:

(1) The administrator shall be the Administrator of the U.S. EPA;

(2) The permitting authority shall be the cabinet;

(3) The citations, Subpart E and 40 CFR 96.42(e) shall be 401 KAR 51:160, NOx requirements for large utility and industrial boilers; and

(4) The citation Subpart I shall be 401 KAR 51:195, NOx opt-in provisions.

Section 2. Applicability. NOx budget units shall comply with the following requirements, which are incorporated by reference in Section 3 of this administrative regulation:

(1) 40 CFR 96.10 to 96.14;

(2) 40 CFR 96.30 to 96.31;

(3) 40 CFR 96.50 to 96.55(b) and 96.56 to 96.57; and

(4) 40 CFR 96.60 to 96.62.

Section 3. Incorporation by Reference. (1) The following material is incorporated by reference:

(a) 40 CFR 96.10 to 96.14, "NOx Authorized Account Representative for NOx Budget Sources," as published in the Code of Federal Regulations, 40 CFR Part 96, July 1, 1999;

(b) 40 CFR 96.30 to 96.31, "Compliance Certification," as published in the Code of Federal Regulations, 40 CFR Part 96, July 1, 1999;

(c) 40 CFR 96.50 to 96.55(b) and 96.56 to 96.57, "NOx Allowance Tracking System," as published in the Code of Federal Regulations, 40 CFR Part 96, July 1, 1999; and

(d) 40 CFR 96.60 to 96.62, "NOx Allowance Transfers," as published in the Code of Federal Regulations, 40 CFR Part 96, July 1, 1999.

(2) This material may be inspected, copied, or obtained at the following offices of the Division for Air Quality, Monday through Friday, 8 a.m. to 4:30 p.m.:

(a) The Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky 40601, (502) 573-3382;

(b) Ashland Regional Office, 3700 Thirteenth Street, Ashland, Kentucky 41105, (606) 920-2067;

(c) Bowling Green Regional Office, 1508 Westen Avenue, Bowling Green, Kentucky 42104, (270) 746-7475;

(d) Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, Kentucky 41042, (859) 525-4923;

(e) Hazard Regional Office, 233 Birch Street, Suite 2, Hazard, Kentucky 41701, (606) 435-6022;

(f) London Regional Office, 875 S. Main Street, London, Kentucky 40741, (606) 330-2080;

(g) Owensboro Regional Office, 3032 Alvey Park Drive, W., Suite 700, Owensboro, Kentucky 42303, (270) 687-7304; and

(h) Paducah Regional Office, 130 Eagle Nest Drive, Paducah, Kentucky, 42003 (270) 898-8468.

(3) Copies of the Code of Federal Regulations (CFR) and the Federal Register (Fed. Reg.) are available for sale from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402. (27 Ky.R. 2611; Am. 3285; eff. 8-15-2001; TAm eff. 8-9-2007.)

401 KAR 51:195. NOx opt-in provisions.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410, 7661

STATUTORY AUTHORITY: KRS 224.10-100, 224.20-100, 224.20.110, 224.20-120, 40 C.F.R. 51.121 as amended at 65 FR 11222 (March 2, 2000), 51.122, 72.2, 75.1, 75.2, 75.4, 75.11-75.13, 75.17, 75.19, 75.20, 75.24, 75.70, 75.72, 75.74, 75.75, Part 96, 42 U.S.C. 7410, 7661

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100 requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. The federal regulation incorporated by reference in this administrative regulation establishes provisions for individual sources to opt into the NOx Budget Trading Program. This administrative regulation is not more stringent nor otherwise different than the provisions of the federal mandate.

Section 1. For purposes of 40 CFR 96.80 to 96.88:

(1) The administrator shall be the Administrator of the U.S. EPA;

(2) The permitting authority shall be the cabinet;

(3) The citations Subpart E, 96.4, 96.5, and 96.42, shall be 401 KAR 51:160;

(4) The citations 96.20, 96.21(c), 96.22, and 96.23, shall be 401 KAR Chapter 52; and

(5) The citation Subparts A through H shall be 401 KAR 51:001, 51:160, 51:170, 51:180, and 51:190.

Section 2. Applicability. Units that opt into the NOx Budget Trading Program shall comply with the requirements of 40 CFR 96.80 to 96.88, which is incorporated by reference in Section 3 of this administrative regulation.

Section 3. Incorporation by Reference. (1) 40 CFR 96.80 to 96.88, "Individual Unit Opt-ins," as published in the Code of Federal Regulations, 40 CFR Part 96, July 1, 1999, is incorporated by reference.

(2) This material may be inspected, copied, or obtained at the following offices of the Division for Air Quality, Monday through Friday, 8 a.m. to 4:30 p.m.:

(a) The Division for Air Quality, 803 Schenkel Lane, Frankfort, Kentucky, 40601, (502) 573-3382;

(b) Ashland Regional Office, 3700 Thirteenth Street, Ashland, Kentucky, 41105, (606) 920-2067;

(c) Bowling Green Regional Office, 1508 Westen Avenue, Bowling Green, Kentucky, 42104, (270) 746-7475;

(d) Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, Kentucky, 41042, (859) 525-4923;

(e) Hazard Regional Office, 233 Birch Street, Suite 2, Hazard, Kentucky, 41701, (606) 435-6022;

(f) London Regional Office, 875 S. Main Street, London, Kentucky, 40741, (606) 330-2080;

(g) Owensboro Regional Office, 3032 Alvey Park Drive, W., Suite 700, Owensboro, Kentucky, 42303, (270) 687-7304; and

(h) Paducah Regional Office, 130 Eagle Nest Drive, Paducah, Kentucky, 42003, (270) 898-8468.

(3) Copies of the Code of Federal Regulations (CFR) and the Federal Register (Fed. Reg) are available for sale from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402. (27 Ky.R. 2614; Am. 3286; eff. 8-15-2001; TAm eff. 8-9-2007.)

224.10-100 Powers and duties of cabinet.

In addition to any other powers and duties vested in it by law, the cabinet shall have the authority, power, and duty to:

(1) Exercise general supervision of the administration and enforcement of this chapter, and all rules, regulations, and orders promulgated thereunder;

(2) Prepare and develop a comprehensive plan or plans related to the environment of the Commonwealth;

(3) Encourage industrial, commercial, residential, and community development which provides the best usage of land areas, maximizes environmental benefits, and minimizes the effects of less desirable environmental conditions;

(4) Develop and conduct a comprehensive program for the management of water, land, and air resources to assure their protection and balance utilization consistent with the environmental policy of the Commonwealth;

(5) Provide for the prevention, abatement, and control of all water, land, and air pollution, including but not limited to that related to particulates, pesticides, gases, dust, vapors, noise, radiation, odor, nutrients, heated liquid, or other contaminants;

(6) Provide for the control and regulation of surface coal mining and reclamation in a manner to accomplish the purposes of KRS Chapter 350;

(7) Secure necessary scientific, technical, administrative, and operational services, including laboratory facilities, by contract or otherwise;

(8) Collect and disseminate information and conduct educational and training programs relating to the protection of the environment;

(9) Appear and participate in proceedings before any federal regulatory agency involving or affecting the purposes of the cabinet;

(10) Enter and inspect any property or premises for the purpose of investigating either actual or suspected sources of pollution or contamination or for the purpose of ascertaining compliance or noncompliance with this chapter, or any regulation which may be promulgated thereunder;

(11) Conduct investigations and hold hearings and compel the attendance of witnesses and the production of accounts, books, and records by the issuance of subpoenas;

(12) Accept, receive, and administer grants or other funds or gifts from public and private agencies including the federal government for the purpose of carrying out any of the functions of the cabinet. The funds received by the cabinet shall be deposited in the State Treasury to the account of the cabinet;

(13) Request and receive the assistance of any state or municipal educational institution, experiment station, laboratory, or other agency when it is deemed necessary or beneficial by the cabinet in the performance of its duties;

(14) Advise, consult, and cooperate with other agencies of the Commonwealth, other states, the federal government, and interstate and interlocal agencies, and affected persons, groups, and industries;

(15) Formulate guides for measuring presently unidentified environmental values and relationships so they can be given appropriate consideration along with social, economic, and technical considerations in decision making;

(16) Monitor the environment to afford more effective and efficient control practices, to identify changes and conditions in ecological systems, and to warn of emergency conditions;

(17) Adopt, modify, or repeal with the recommendation of the commission any standard, regulation, or plan specified in KRS 224.01-110 (5) and (6);

(18) Issue, after hearing, orders abating activities in violation of this chapter, or the provisions of this chapter, or the regulations promulgated pursuant thereto and requiring the adoption of the remedial measures the cabinet deems necessary;

(19) Issue, continue in effect, revoke, modify, suspend, or deny under such conditions as the cabinet may prescribe and require that applications be accompanied by plans, specifications, and other information the cabinet deems necessary for the following permits:

(a) Permits to discharge into any waters of the Commonwealth, and for the installation, alteration, expansion, or operation of any sewage system; however, the cabinet may refuse to issue the permits to any person, or any partnership, corporation, etc., of which the person owns more than ten percent (10%) interest, who has improperly constructed, operated, or maintained a sewage system willfully, through negligence, or because of lack of proper knowledge or qualifications until the time that person demonstrates proper qualifications to the cabinet and provides the cabinet with a performance bond;

(b) Permits for the installation, alteration, or use of any machine, equipment, device, or other article that may cause or contribute to air pollution or is intended primarily to prevent or control the emission of air pollution; or

(c) Permits for the establishment or construction and the operation or maintenance of waste disposal sites and facilities;

(20) May establish, by regulation, a fee or schedule of fees for the cost of processing applications for permits authorized by this chapter, and for the cost of processing applications for exemptions or partial exemptions which may include but not be limited to the administrative costs of a hearing held as a result of the exemption application, except that applicants for existing or proposed publicly owned facilities shall be exempt from any charge, other than emissions fees assessed pursuant to KRS 224.20-050, and that certain nonprofit organizations shall be charged lower fees to process water discharge permits under KRS 224.16-050(5);

(21) May require for persons discharging into the waters or onto the land of the Commonwealth, by regulation, order, or permit, technological levels of treatment and effluent limitations;

(22) Require, by regulation, that any person engaged in any operation regulated pursuant to this chapter install, maintain, and use at such locations and intervals as the cabinet may prescribe any equipment, device, or test and the methodologies and

procedures for the use of the equipment, device, or test to monitor the nature and amount of any substance emitted or discharged into the ambient air or waters or land of the Commonwealth and to provide any information concerning the monitoring to the cabinet in accordance with the provisions of subsection (23) of this section;

(23) Require by regulation that any person engaged in any operation regulated pursuant to this chapter file with the cabinet reports containing information as to location, size, height, rate of emission or discharge, and composition of any substance discharged or emitted into the ambient air or into the waters or onto the land of the Commonwealth, and such other information the cabinet may require;

(24) Promulgate regulations, guidelines, and standards for waste planning and management activities, approve waste management facilities, develop and publish a comprehensive statewide plan for nonhazardous waste management which shall contain but not be limited to the provisions set forth in KRS 224.43-345, and develop and publish a comprehensive statewide plan for hazardous waste management which shall contain but not be limited to the following:

(a) A description of current hazardous waste management practices and costs, including treatment and disposal, within the Commonwealth;

(b) An inventory and description of all existing facilities where hazardous waste is being generated, treated, recycled, stored, or disposed of, including an inventory of the deficiencies of present facilities in meeting current hazardous waste management needs and a statement of the ability of present hazardous waste management facilities to comply with state and federal laws relating to hazardous waste;

(c) A description of the sources of hazardous waste affecting the Commonwealth including the types and quantities of hazardous waste currently being generated and a projection of such activities as can be expected to continue for not less than twenty (20) years into the future; and

(d) An identification and continuing evaluation of those locations within the Commonwealth which are naturally or may be engineered to be suitable for the establishment of hazardous waste management facilities, and an identification of those general characteristics, values, and attributes which would render a particular location unsuitable, consistent with the policy of minimizing land disposal and encouraging the treatment and recycling of the wastes.

The statewide waste management plans shall be developed consistent with state and federal laws relating to waste;

(25) Perform other acts necessary to carry out the duties and responsibilities described in this section;

(26) Preserve existing clean air resources while ensuring economic growth by issuing regulations, which shall be no more stringent than federal requirements, setting maximum allowable increases from stationary sources over baseline concentrations

of air contaminants to prevent significant deterioration in areas meeting the state and national ambient air quality standards;

(27) Promulgate regulations concerning the bonding provisions of subsection (19)(a) of this section, setting forth bonding requirements, including but not limited to requirements for the amount, duration, release, and forfeiture of the bonds. All funds from the forfeiture of bonds required pursuant to this section shall be placed in the State Treasury and credited to a special trust and agency account which shall not lapse. The account shall be known as the "sewage treatment system rehabilitation fund" and all moneys placed in the fund shall be used for the elimination of nuisances and hazards created by sewage systems which were improperly built, operated, or maintained, and insofar as practicable be used to correct the problems at the same site for which the bond or other sureties were originally provided; and

(28) Promulgate administrative regulations not inconsistent with the provisions of law administered by the cabinet.

Effective: August 30, 2007

History: Amended 2007 (2d Extra. Sess.) Ky. Acts ch. 1, sec. 42, effective August 30, 2007. -- Amended 1994 Ky. Acts ch. 162, sec. 3, effective July 15, 1994. -- Amended 1990 Ky. Acts ch. 325, sec. 15, effective July 13, 1990; and ch. 412, sec. 1, effective July 13, 1990. -- Amended 1986 Ky. Acts ch. 455, sec. 1, effective July 15, 1986. -- Amended 1984 Ky. Acts ch. 111, sec. 109, effective July 13, 1984. -- Amended 1980 Ky. Acts ch. 264, sec. 2; and ch. 377, sec. 10, effective July 15, 1980. -- Amended 1978 Ky. Acts ch. 113, sec. 3, effective June 17, 1978; and ch. 266, sec. 2, effective June 17, 1978. -- Amended 1974 Ky. Acts ch. 355, sec. 2, effective June 21, 1974. -- Created 1972 (1st Extra. Sess.) Ky. Acts ch. 3, sec. 3, effective January 1, 1973.

Formerly codified as KRS 224.033

Legislative Research Commission Note (9/28/93). The Division of Energy within the Department for Natural Resources of the Natural Resources and Environmental Protection Cabinet was made "responsible for subsections (28) and (29)" of this statute by 1990 Ky. Acts, ch. 325, sec. 14.

Legislative Research Commission Note (6/20/2005). 2005 Ky. Acts ch. 123, sec. 5, codified at KRS 224.10-103, provides that the Division of Energy and all "personnel, functions, powers, and duties of the Division of Energy shall be transferred to the Tourism Development Cabinet." The abolition of the Tourism Development Cabinet and creation of the Commerce Cabinet under Executive Order 2004-729 were confirmed by 2005 Ky. Acts ch. 95, in which the Office of Energy Policy is established and statutory references to the "Division of Energy" are changed to the "Office of Energy Policy."

401 KAR 50:012. General application.

RELATES TO: KRS 224.10-100, 224.20-120, 40 C.F.R. 60.14, 42 U.S.C. 7401 et seq., 7408, 7410

STATUTORY AUTHORITY: KRS 224.10-100

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100 requires the Environmental and Public Protection Cabinet to prescribe administrative regulations for the prevention, abatement, and control of air pollution. 42 USC 7410 likewise requires the state to implement standards for national primary and secondary ambient air quality. This administrative regulation provides guidelines by which all administrative regulations of 401 KAR Chapters 50 to 65, are to be understood.

Section 1. General Application of Administrative Regulations and Standards. Administrative Regulations of the cabinet shall be construed and applied according to subsections (1) through (6) of this section, which shall guide the cabinet in the issuance, modification, and revocation of permits.

(1) All major sources of VOCs located in a county or portion of a county which is designated ozone nonattainment, for any nonattainment classification except marginal, under 401 KAR 51:010, shall install and use control technology which is reasonable and available.

(a) The determination of reasonably available control technology shall be approved by the cabinet and shall be based upon:

1. A Control Techniques Guidelines Document issued by the U.S. EPA and promulgated in regulatory form by the cabinet; or

2. If no Control Techniques Guidelines Document is appropriate, the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. The cabinet may require technology that has been applied to similar, but not necessarily identical source categories.

(b) For those reasonably available control technology determinations not based on a control techniques guidelines document, the cabinet shall:

1. Hold a public hearing on the determination.

2. Submit the determination to the U.S. EPA for approval.

(c) For these determinations, that portion of a source with facilities uncontrolled by reasonably available control technology which emit VOCs that sum to 100 tpy or greater shall be considered a major source.

(2) In the absence of a standard specified in these administrative regulations, all major air contaminant sources shall as a minimum apply control procedures that are reasonable, available, and practical.

(3) Nothing in these administrative regulations is intended to permit a practice which is in violation of a statute, ordinance, or administrative regulation.

(4) These administrative regulations shall be complementary to each other, and to other administrative regulations adopted by the cabinet. If a provision of these administrative regulations or the application thereof to a person or circumstance is held to be invalid, the invalidity shall not affect other provisions or application of another part of these administrative regulations and to this end each provision of these administrative regulations and the various applications thereof are declared to be severable.

(5) Except as provided by 401 KAR 50:055, nothing in these administrative regulations shall allow a source to remove control equipment or discontinue procedures previously required in a nonattainment area to achieve the national ambient air quality standards until a state implementation plan containing different requirements has been approved by the U.S. EPA.

(6) For the purpose of applying the definition of modification, an increase in the amount of an air pollutant shall be determined as in 40 CFR 60.14. (5 Ky.R. 352; eff. 6-6-79; Recodified from 401 KAR 50:005, 7-31-90; Am. 18 Ky.R. 2604; 2929; 3333; eff. 6-24-92; 24 Ky.R. 648; eff. 11-12-97; TAm eff. 8-9-2007.)

401 KAR 63:005. Open burning.

RELATES TO: KRS 149.400, 224.10-100, 224.20-100, 224.20-110, 224.20-120, 42 U.S.C. 7401-7671q
STATUTORY AUTHORITY: KRS 224.10-100, 224.20-110
NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100 requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. KRS 224.20-110 prohibits any person from directly or indirectly, emitting into or discharging into the air under the jurisdiction of the commonwealth, or causing, permitting, or allowing to be emitted or discharged into the air, any contaminants as provided for in subsection (1) of KRS 224.01-010 that shall cause or contribute to the pollution of the air of the commonwealth in contravention of any of the rules, administrative regulations, or orders of the cabinet. This administrative regulation establishes requirements for the control of open burning.

Section 1. Definitions.
(1) "Clean lumber" means wood or wood products that have been cut or shaped and includes wet, air-dried, and kiln-dried wood products and does not include commercial or industrial waste or wood products that have been painted, pigment-stained, or pressure-treated using any hazardous or toxic compounds.
(2) "Fire training" means the instruction of industrial, public and private firefighters conducted in accordance with safety standards and procedures as accepted by the Kentucky State Fire Marshal, the Kentucky Fire Commission or the National Wildfire Coordinating Group.
(3) "Garbage" means putrescible animal and vegetable matter accumulated in the course of ordinary day-to-day living.
(4) "Household rubbish" means waste material and trash normally accumulated by a family in a residence in the course of ordinary day-to-day living, except for garbage, cans, glass, plastic, or other potentially hazardous waste materials.
(5) "Land clearing" means clearing of land for agricultural, residential, industrial, or commercial development purposes, including the construction of roads.
(6) "Open burning" means the burning of any matter without a burn chamber approved by the Kentucky Division for Air Quality, or without a stack or chimney with control devices approved by the Kentucky Division for Air Quality.
(7) "Priority I Region" means a region classified as Priority I in 401 KAR 50:020, Appendix A.
(8) "Recognized agricultural, silvicultural, range, ecological, or wildlife management practices" means burning recognized by the Kentucky Department of Agriculture, the United States Department of Agriculture, the Kentucky Division of Forestry, the United States Forest Service, the Kentucky Department of Fish and Wildlife, the Kentucky State Nature Preserves Commission, or the United States Fish and Wildlife Service as necessary to promote cultivation of crops, range, and forest lands, weed and understory abatement and pest control and prevention.
(9) "Wood waste" means untreated wood and untreated wood products, including tree stumps (whole or chipped), felled trees, tree limbs (whole or chipped), bark, sawdust, chips, scraps, slabs, millings and shavings. Wood waste does not include:
(a) Yard waste;
(b) Construction, renovation, or demolition wastes; or
(c) Clean lumber.
(10) "Yard waste" means grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs, which come from residential, commercial, retail, institutional, or industrial sources as part of maintaining yards or other private or public lands. Yard waste does not include:
(a) Construction, renovation, and demolition wastes; or
(b) Clean lumber.

Section 2. Applicability. This administrative regulation shall apply to all open burning that is not subject to another administrative regulation in 401 KAR Chapters 50 to 65.

Section 3. Prohibition of Open Burning. Except as provided in Sections 4 and 5 of this administrative regulation, open burning shall be prohibited.

Section 4. Allowable Open Burning. Subject to the limitations contained in this section and the restrictions contained in Section 5 of this administrative regulation, open burning shall be allowed for:
(1) Fires set for the cooking of food for human consumption;
(2) Fires set for recreational or ceremonial purposes;
(3) Small fires set by construction and other workers for comfort heating purposes if:
(a) The ambient temperature is below fifty (50) degrees Fahrenheit;
(b) Excessive or unusual smoke is not created;
(c) Only clean lumber or vegetative matter is burned; and
(d) The fire is burned in a container not exceeding fifty-five (55) gallons in size;
(4) Fires set for the purpose of weed abatement, disease, and pest prevention;
(5) Fires set for prevention of a fire hazard, including the disposal of dangerous materials if no safe alternative is available;
(6) Fires set for the purpose of instruction and training of public and industrial employees in the methods of fighting fires as set forth in Section 6 of this administrative regulation;
(7) Fires set for recognized agricultural, silvicultural, range, ecological, and wildlife management practices;
(8) Fires set by individual homeowners for burning of leaves except in cities greater than 8,000 population located in a Priority I Region;
(9) Fires for disposal of household rubbish, which shall not include garbage, originating at dwellings of five (5) family units or less, if the fires are maintained by an occupant of the dwelling at the dwelling, except in cities greater than 8,000 population located in a Priority I Region;
(10) Fires set for the purpose of disposing of accidental spills or leaks of crude oil, petroleum products or other organic materials, and the disposal of absorbent material used in their removal, if no other economically feasible means of disposal is available and practical. Permission shall be obtained from the cabinet prior to burning;
(11) Fires set for disposal of natural growth for land clearing and maintenance, and trees and tree limbs felled by storms if no extraneous materials, such as tires or heavy oil which tend to produce dense smoke, are used to cause ignition or aid combustion and the burning is done on days when conditions do not pose a threat of igniting a forest fire. In regions classified Priority I, with respect to particulate matter pursuant to 401 KAR 50:020, Appendix A, the emissions from these fires shall not be equal to or greater than forty (40) percent opacity;
(12) Heating ropes that are set on fire to repair steel rails during cold weather; and
(13) Fires set by county or municipal governments to dispose of wood waste or clean lumber. This activity shall not be considered in violation of 401 KAR 47:030, Section 10.

Section 5. Restrictions to Open Burning. (1) For those counties, or portions of counties, which are, or were previously, designated moderate nonattainment for the one (1) hour ozone or nonattainment for the National Ambient Air Quality Standards (NAAQS) PM_{10} or those counties, or portions of counties, which are, or were designated nonattainment for the eight (8) hour ozone or $PM_{2.5}$ national ambient air quality standards, pursuant to 401

KAR 51:010, fires may be set in accordance with this administrative regulation except during the months of May, June, July, August, and September. During these months, the only open burning activities allowed shall be:

(a) Fires set for the cooking of food for human consumption;

(b) Fires set for prevention of a fire hazard, including disposal of dangerous materials if no safe alternative is available;

(c) Fires set for the purpose of bona fide instruction and training of public and industrial employees in the methods of fighting fires;

(d) Fires set for recognized agricultural, silvicultural, range, ecological, and wildlife management practices;

(e) Fires set for the purpose of disposing of accidental spills or leaks of crude oil, petroleum products or other organic materials, and the disposal of absorbent material used in their removal, if no other economically feasible means of disposal is available and practical. Permission shall be obtained from the cabinet prior to burning; and

(f) Fires set for recreational or ceremonial purposes.

(2) Open burning shall comply with the fire hazard season requirements of KRS 149.400.

(3) Open burning for land clearing purposes associated with residential, commercial, or industrial development shall be limited to a maximum of two (2) contiguous acres at any one (1) time.

(4) This administrative regulation shall not authorize open burning that is prohibited by any local ordinance.

Section 6. Procedures for Fire Training. Burning conducted in conjunction with training for public, private and industrial firefighters shall be subject to the following criteria:

(1) Excluding fire training that has been approved by the Kentucky State Fire Marshal, or which has been certified by the Kentucky State Fire Commission, or which is conducted in accordance with standards adopted by the National Wildfire Coordinating Group, any entity intending to conduct fire training shall submit written notification to the local Division for Air Quality regional office a minimum of fifteen (15) days prior to the scheduled training. The written notification shall state the location and the date of the proposed fire training, the name and contact information for the on-site training coordinator, the number of firefighters to be trained, the goals and the objectives of the training, and a brief summary of what is to be taught.

(2) Any materials that contain asbestos shall not be burned.

(3) Materials likely to produce hazardous or toxic emissions shall be removed prior to the fire training burning event, to the extent practicable, and properly disposed.

(4) Excluding fire training approved by the Kentucky Division of Forestry or the Kentucky State Fire Marshal, or which has been certified by the Kentucky State Fire Commission, or which is conducted in accordance with standards adopted by the National Wildfire Coordinating Group, entities conducting fire training shall be limited to one burning event related to training per year for every ten firefighters under their supervision.

(5) Excluding fire training approved by the Kentucky Division of Forestry or the Kentucky State Fire Marshal, or which has been certified by the Kentucky State Fire Commission, or which is conducted in accordance with standards adopted by the National Wildfire Coordinating Group, between May 1 and September 30, fire training shall not be conducted in any counties, or portions of counties, which are, or were previously, designated moderate nonattainment for ozone, or designated, or previously designated, nonattainment for the eight (8) hour ozone or $PM_{2.5}$ (particulate matter) national ambient air quality standard, pursuant to 401 KAR 51:010. (5 Ky.R. 510; eff. 6-6-79; Am. 10 Ky.R. 634; eff. 3-1-84; 24 Ky.R. 654; 1299; eff. 1-12-98; 31 Ky.R. 1354; 32 Ky.R. 63; eff. 7-13-2005.)

401 KAR 63:010. Fugitive emissions.

RELATES TO: KRS Chapter 224

STATUTORY AUTHORITY: KRS 224.10-100

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100 requires the Environmental and Public Protection Cabinet to prescribe administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation provides for the control of fugitive emissions.

Section 1. Applicability. The provisions of this administrative regulation are applicable to each affected facility as defined in Section 2 of this administrative regulation.

Section 2. Definitions. Terms used in this administrative regulation not defined herein shall have the meaning given to them in 401 KAR 50:010.

(1) "Affected facility" means an apparatus, operation, or road which emits or may emit fugitive emissions provided that the fugitive emissions from such facility are not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

(2) "Fugitive emissions" means the emissions of any air contaminant into the open air other than from a stack or air pollution control equipment exhaust.

(3) "Open air" means the air outside buildings, structures, and equipment.

(4) "Classification date" means the effective date of this administrative regulation.

Section 3. Standards for Fugitive Emissions. (1) No person shall cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

(a) Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

(b) Application and maintenance of asphalt, oil, water, or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts;

(c) Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or other similar operations;

(d) Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne;

(e) The maintenance of paved roadways in a clean condition;

(f) The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water.

(2) No person shall cause or permit the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate.

(3) When dust, fumes, gases, mist, odorous matter, vapors, or any combination thereof escape from a building or equipment in such a manner and amount as to cause a nuisance or to violate any administrative regulation, the secretary may order that the building or equipment in which processing, handling and storage are done be tightly closed and ventilated in such a way that all air and gases and air or gas-borne material leaving the building or equipment are treated by removal or destruction of air contaminants before discharge to the open air.

(4) The provisions of this administrative regulation shall not apply to agricultural practices, such as tilling of land or application of fertilizers, which take place on a farm.

Section 4. Additional Requirements. In addition to the requirements of Section 3 of this administrative regulation, the following shall apply:

(1) At all times when in motion, open bodied trucks, operating outside company property, transporting materials likely to become airborne shall be covered.

(2) Agricultural practices, such as tilling of land or application of fertilizers, which take place on a farm shall be conducted in such a manner as to not create a nuisance to others residing in the area. Agricultural practices are not subject to the opacity standard.

(3) The provisions of Section 3(1) and (2) of this administrative regulation shall not be applicable to temporary blasting or construction operations.

(4) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway. (5 Ky.R. 511; Am. 6 Ky.R. 50; eff. 6-29-1979; TAm eff. 8-9-2007.)

Appendix H

Ohio and Indiana

Redesignation to Attainment

Request

Submittal

Environmental Protection Agency

Ted Strickland, Governor
Lee Fisher, Lt. Governor
Chris Korleski, Director

DEC 0 9 2010

Ms. Susan Hedman
Regional Administrator
U.S. EPA Region V
77 W. Jackson Blvd.
Chicago, IL 60604

Re: $PM_{2.5}$ redesignation request for the 1997 $PM_{2.5}$ Annual Standard for the Cincinnati-Hamilton Area

Dear Administrator Hedman:

I am writing to formally request a redesignation to attainment of the Ohio portion of the Cincinnati-Hamilton, OH-IN-KY area (Butler, Clermont, Hamilton, and Warren Counties in Ohio; Dearborn Township in Indiana; and Boone, Campbell, and Kenton Counties in Kentucky) with respect to the 1997 $PM_{2.5}$ annual standard. The enclosed submittal combines the redesignation request and the required maintenance plan for this area.

Monitoring of existing air quality indicates that the 1997 National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$ has been attained throughout this area based on 2007-2009 air quality data. Emissions projections indicate that current controls, existing State rules, existing federal rules, and Ohio's PSD program will be more than sufficient to maintain the NAAQS indefinitely into the future. These programs will, therefore, constitute the attainment and maintenance plan for Ohio's portion of the Cincinnati-Hamilton area.

The enclosed information, compiled by the Ohio Environmental Protection Agency (Ohio EPA), Ohio Department of Transportation, and the Ohio, Indiana, and Kentucky Regional Council of Governments (associated planning organization), shows significant emission reductions in point and mobile sources since ambient violations have occurred. A significant portion of the improved air quality can be attributed to federal programs for the mobile source sector, the regional reductions associated with the NOx Trading Program, and control strategies implemented by Ohio, such as Low Reid Vapor Pressure Fuel requirements.

The public hearing for this package was held on November 29, 2010, in Cincinnati, Ohio and public comments were accepted through November 30, 2010.

50 West Town Street, Suite 700
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If you have questions, please contact Jennifer Hunter in our Division of Air Pollution Control at (614) 644-3696.

Sincerely,

Chris Korleski
Director

REDESIGNATION REQUEST AND MAINTENANCE PLAN FOR THE OHIO PORTION OF THE CINCINNATI-HAMILTON, OH-KY-IN ANNUAL $PM_{2.5}$ NONATTAINMENT AREA

Butler, Clermont, Hamilton,
and Warren Counties, Ohio

Prepared by:
Ohio Environmental Protection Agency
Division of Air Pollution Control

December 2010

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REDESIGNATION REQUEST AND MAINTENANCE PLAN FOR THE OHIO PORTION OF THE CINCINNATI-HAMILTON, OH-KY-IN ANNUAL $PM_{2.5}$ NONATTAINMENT AREA

Butler, Clermont, Hamilton, and Warren Counties, Ohio

CHAPTER ONE

Introduction

The Clean Air Act (CAA) requires areas failing to meet the National Ambient Air Quality Standard (NAAQS) for the annual $PM_{2.5}$ to develop State Implementation Plans (SIP's) to expeditiously attain and maintain the standard. The United States Environmental Protection Agency (U.S. EPA) revised the NAAQS for particulate matter in July 1997. It replaced the existing PM_{10} standard with a health based $PM_{2.5}$ standard and retained the PM_{10} standard as a "coarse" standard protecting welfare. The standards include an annual standard set at 15.0 micrograms per cubic meter ($\mu g/m^3$), based on the 3-year average of annual mean $PM_{2.5}$ concentrations and a 24-hour standard of 65 $\mu g/m^3$, based on the 3-year average of the 98^{th} percentile of 24-hour concentrations.

The revised NAAQS were legally challenged in the U.S. Court of Appeals for the District of Columbia Circuit (The D.C. Circuit). On May 14, 1999, the D.C. Circuit remanded, without vacatur, the standard back to U.S. EPA. The remand did not question the level at which U.S. EPA set the standards but rather the constitutionality of the CAA provision that authorizes U.S. EPA to set national air quality standards. U.S. EPA requested a rehearing which the D.C. Circuit denied. Therefore, in December 1999, U.S. EPA appealed the D.C. Circuit decision to the U.S. Supreme Court. The U.S. Supreme Court issued a decision on February 27, 2001 that unanimously affirmed the constitutionality of the CAA provision but did remand several other issues back to the D.C. Circuit, including the issue of whether U.S. EPA acted arbitrarily and capriciously in establishing the specific levels of the standards.

The D.C. Circuit heard arguments in this remanded case in December 2001, and issued its decision on March 26, 2002. The D.C. Circuit rejected the claims that the U.S. EPA had acted arbitrarily and capriciously in setting the levels of the standards.

On December 17, 2004, U.S. EPA promulgated the initial $PM_{2.5}$ nonattainment areas designations for the $PM_{2.5}$ standards across the country. Modifications to those designations were made and an effective date was set at April 5, 2005. Unlike Subpart 2 of the CAA Amendments of 1990 which defined five ozone nonattainment classifications for the areas that exceed the NAAQS based on the

severity of the ozone levels, $PM_{2.5}$ nonattainment designations are simply labeled "nonattainment." The CAA Amendments require states with $PM_{2.5}$ nonattainment areas to submit a plan within three years of the effective date of the designations (April 5, 2008) detailing how the $PM_{2.5}$ standards will be attained by April 5, 2010. Ohio EPA submitted its attainment demonstration for the entire State of Ohio on July 16, 2008.

Section 107(d)(3)(E) of the CAA allows states to request nonattainment areas to be redesignated to attainment provided certain criteria are met. The following are the criteria that must be met in order for an area to be redesignated from nonattainment to attainment:

i) A determination that the area has attained the $PM_{2.5}$ standard.
ii) An approved State Implementation Plan (SIP) for the area under Section 110(k).
iii) A determination that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the SIP and other federal requirements.
iv) A fully approved maintenance plan under Section 175(A).
v) A determination that all Section 110 and Part D requirements have been met.

This document addresses each of these requirements, and provides additional information to support continued compliance with the annual $PM_{2.5}$ standard.

Geographical Description and Background

The current Cincinnati-Hamilton nonattainment area is located in southwest Ohio and includes the following counties: Butler, Clermont, Hamilton, and Warren in Ohio; Dearborn (partial nonattainment of Lawrenceburg Township only) in Indiana; and Boone, Campbell, and Kenton in Kentucky. This area is shown in Figure 1 under Chapter Three.

The Cincinnati-Hamilton area has not previously been subject to nonattainment area rulemakings for fine particles.

As a result of the 2005 $PM_{2.5}$ designations, U.S. EPA designated the Cincinnati-Hamilton area nonattainment for the 15.0 $\mu g/m^3$ annual standard[1], and Ohio EPA was required to develop a plan to reduce oxides of nitrogen (NO_x), sulfur dioxide (SO_2) and direct $PM_{2.5}$ emissions and to demonstrate that the area will meet the federal annual air quality standard by April 5, 2010. Ohio's main $PM_{2.5}$ components are primary particles (organic carbon, crustal material, and elemental carbon), SO2 and NO_x, which were included in the attainment demonstration analysis. Volatile organic compounds (VOCs) and ammonia (NH3) were not included in the analysis since they were not part of Ohio's

1 There were no monitors in Ohio that violated the 1997 24-hour $PM_{2.5}$ standard of 65$\mu g/m^3$.

current attainment strategy for $PM_{2.5}$ (although controls for VOCs have been implemented for ozone nonattainment). This is consistent with U.S. EPA's "Clean Air Particle Implementation Rule" [74FR 20856] (hereafter referred to as "Implementation Rule"). In the Implementation Rule U.S. EPA presumes NH3 emissions are not a $PM_{2.5}$ attainment plan precursor and that States are not required to address VOC unless the State or U.S. EPA makes technical demonstration that emissions of VOCs significantly contribute to nonattainment.

This document is intended to support Ohio's request that the Ohio portions of the Cincinnati-Hamilton area be redesignated from nonattainment to attainment for the annual $PM_{2.5}$ standard. In addition, the States of Kentucky and Indiana also intend to submit requests for their respective portions of the Cincinnati-Hamilton area.

Status of Air Quality

$PM_{2.5}$ complete quality-assured ambient air quality monitoring data for the most recent three (3) years, 2007 through 2009, demonstrate that the air quality has met the NAAQS for annual $PM_{2.5}$ in this nonattainment area. The NAAQS attainment, accompanied by decreases in emission levels discussed in Chapter Four, supports a redesignation to attainment for the Cincinnati-Hamilton area based on the requirements in Section 107(d)(3)(E) of the CAA.

CHAPTER TWO

Requirements for Redesignation

U.S. EPA has published detailed guidance in a document entitled *Procedures for Processing Requests to Redesignate Areas to Attainment* (redesignation guidance), issued September 4, 1992, to Regional Air Directors. The redesignation request and maintenance plan are based on the redesignation guidance, supplemented with additional guidance received from staff of U.S. EPA Region V.

Below is a summary of each redesignation criterion as it applies to the Cincinnati-Hamilton area.

i.) Attainment of the standard (CAA Section 107(d)(3)(E)(i))

There are two components involved in making this demonstration. The first component relies on ambient air quality data. The data that are used to demonstrate attainment should be the product of ambient monitoring that is representative of the area of highest concentration. The data should be collected and quality-assured in accordance with 40 CFR 58 and recorded in the Air Quality System (AQS) in order for it to be available to the public for review.

The second component relies upon supplemental U.S. EPA-approved air quality modeling. While no modeling is required for redesignating nonattainment areas, the redesignation guidance states it is "generally necessary" for particulate matter redesignations. Appendix C and Appendix D contains the most recent modeling results showing future attainment and maintenance are provided. Chapter Three discusses this requirement in more detail and provides the attainment demonstration.

ii.) Permanent and enforceable improvement in air quality (CAA Section 107(d)(3)(E)(iii))

The state must be able to reasonably attribute the improvement in air quality to emission reductions which are permanent and enforceable. The state should estimate the percent reduction achieved from federal measures as well as control measures that have been adopted and implemented by the state.

It was not necessary for Ohio to adopt or implement control measures for these counties beyond the federal measures.

Ohio EPA has adopted several rules recently that will have an impact Statewide on $PM_{2.5}$ emissions in the future:

- Clean Air Interstate Rule (CAIR)
- NOx SIP Call Rules

In addition, since the initial designations were made federally enforceable consent decrees have resulted in reductions in emissions from utilities across the state, including this area.

Chapters Four and Five discuss this requirement in more detail.

iv.) Section 110 and Part D requirements (CAA Section 107(d)(3)(E)(v))

For purposes of redesignation, a state must meet all requirements of Section 110 and Part D that were applicable prior to submittal of the complete redesignation request.

Subpart 1 of Part D consists of general requirements applicable to all areas which are designated nonattainment based on a violation of the NAAQS. Subpart 4 of Part D consists of more specific requirements applicable to particulate matter (specifically to address PM_{10}). However, for the purpose of implementing the 1997 $PM_{2.5}$ standard, U.S. EPA's Implementation Rule stated Subpart 1, rather than Subpart 4, is appropriate for the purpose of implementing $PM_{2.5}$.[72 FR 20589]

i.) Section 110(a) requirements

Section 110(a) of Title I of the CAA contains the general requirements for a SIP. Section 110(a)(2) provides that the implementation plan submitted by a state must have been adopted by the state after reasonable public notice and hearing, and that, among other things, it must include enforceable emission limitations and other control measures, means or techniques necessary to meet the requirements of the CAA; provide for establishment and operation of appropriate devices, methods, systems and procedures necessary to monitor ambient air quality; provide for implementation of a source permit program to regulate the modification and construction of any stationary source within the areas covered by the plan; include provisions for the implementation of Part C, prevention of significant deterioration (PSD) and Part D, NSR permit programs; include criteria for stationary source emission control measures, monitoring, and reporting; include provisions for air quality modeling; and provides for public and local agency participation in planning and emission control rule development. In Ohio's December 5, 2007 and September 4, 2009 infrastructure SIP submissions, Ohio

verified that the State fulfills the requirements of Section 110(a)(2) of the Act.

Section 110(a)(2)(D) also requires State plans to prohibit emissions from within the State which contribute significantly to nonattainment or maintenance areas in any other State, or which interfere with programs under Part C to prevent significant deterioration of air quality or to achieve reasonable progress toward the national visibility goal for Federal class I areas (national parks and wilderness areas). In order to assist States in addressing their obligations regarding regionally transported pollution, U.S. EPA finalized CAIR to reduce SO_2 and NO_x emissions from large electric generating units (EGU). Ohio has met the requirements of the federal CAIR to reduce NO_x and SO_2 emissions contributing to downwind states. On February 1, 2008, U.S. EPA approved Ohio's CAIR program, which can be found in Ohio Administrative Code (OAC) Chapter 3745-109[2]. On July 6, 2010, U.S. EPA proposed a replacement to the CAIR program, the Transport Rule. [75 FR 45210] Upon finalization, it will further assist States in addressing their obligations regarding regionally transported pollution by providing reductions in NO_x and SO_2 emissions in 2012 and 2014.

ii.) Section 172(c) requirements

This Section contains general requirements for nonattainment plans. The requirements for reasonable further progress, identification of certain emissions increases, and other measures needed for attainment will not apply for redesignations because they only have meaning for areas not attaining the standard. The requirements for an emission inventory will be satisfied by the inventory requirements of the maintenance plan. Chapters Four and Five discuss this requirement in more detail.

iii.) Conformity

The state must work with U.S. EPA to show that its SIP provisions are consistent with the Section 176(c)(4) conformity requirements. The redesignation request should include conformity procedures, if the state already has these procedures in place. If a state does not have conformity procedures in place at the time that it submits a

2 http://www.epa.ohio.gov/dapc/regs/regs.aspx#3745-109

redesignation request, the state must commit to follow U.S. EPA's conformity regulation upon issuance, as applicable.

v.) Maintenance plans (CAA Section 107(d)(3)(E)(iv))

Section 107(d)(3)(E) stipulates that for an area to be redesignated, U.S. EPA must fully approve a maintenance plan that meets the requirements of Section 175(A). The maintenance plan will constitute a SIP revision and must provide for maintenance of the relevant NAAQS in the area for at least 10 years after redesignation. Section 175 (A) further states that the plan shall contain such additional measures, if any, as may be necessary to ensure such maintenance.

In addition, the maintenance plan shall contain such contingency measures as the Administrator deems necessary to ensure prompt correction of any violation of the NAAQS. At a minimum, the contingency measures must include a requirement that the state will implement all measures contained in the nonattainment SIP prior to redesignation.

States seeking redesignation of a nonattainment area should consider the following provisions:

a.) attainment inventory;
b.) maintenance demonstration;
c.) monitoring network;
d.) verification of continued attainment; and
e.) contingency plan.

Chapter Six discusses this requirement in more detail.

CHAPTER THREE

$PM_{2.5}$ MONITORING
CAA Section 107(d)(3)(E)(i)

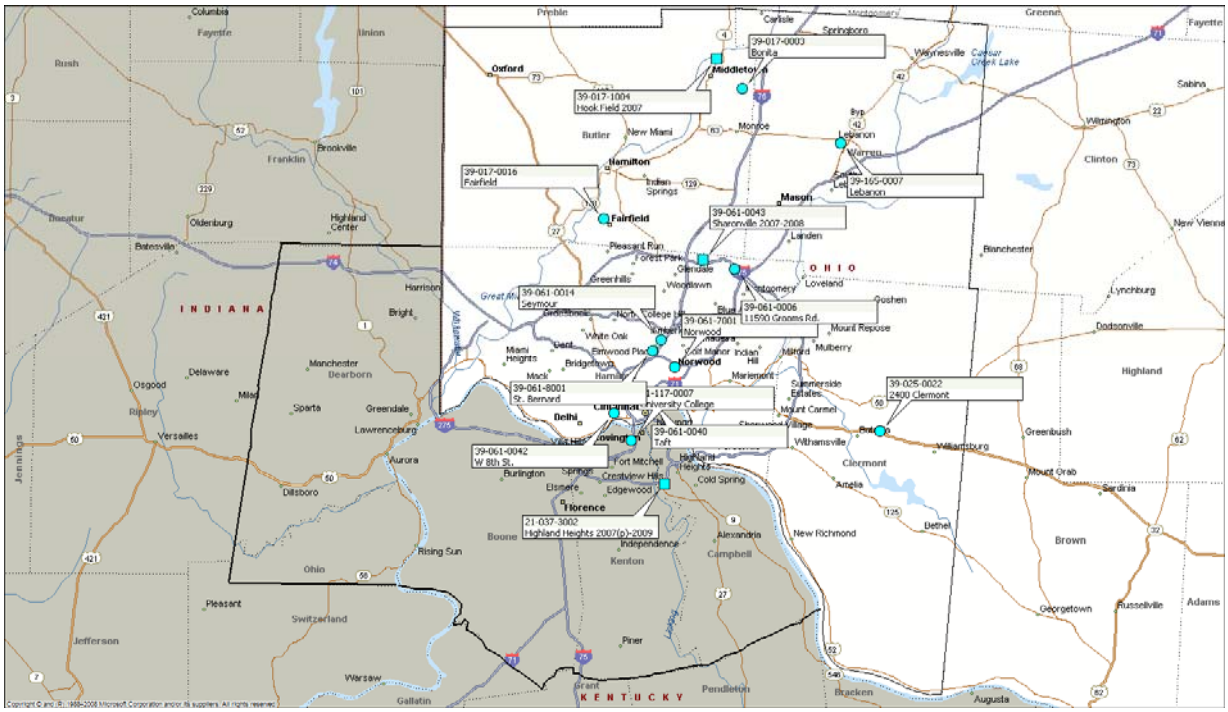
Requirement 1 of 4
A demonstration that the NAAQS for annual $PM_{2.5}$, as published in 40 CFR 50.7, has been attained.

Background
There are sixteen monitors measuring $PM_{2.5}$ concentrations in this nonattainment area. Twelve of the sixteen monitors are located in Ohio[3] and are operated by Ohio EPA Division of Air Pollution Control, Southwest District Office and the Hamilton County Division of Environmental Services. A listing of the design values based on the three-year average of the annual mean concentrations from 2007 through 2009 is shown in Table 1. The locations of the monitoring sites for this nonattainment area are shown on Figure 1.

3 The four remaining $PM_{2.5}$ monitors are located in Kentucky.

Demonstration

Figure 1 - Map of the Cincinnati-Hamilton, OH-KY-IN nonattainment area and monitor locations



Requirement 2 of 4

Ambient monitoring data quality assured in accordance with 40 CFR 58.10, recorded in the U.S. EPA air quality system (AQS) database, and available for public view.

Demonstration

The Ohio EPA has quality assured all data shown in Appendix A in accordance with 40 CFR 58.10 and all other federal requirements. Ohio EPA has recorded the data in the AQS database and, therefore, the data are available to the public.

Requirement 3 of 4

A showing that the three-year average of the annual mean values, based on data from all monitoring sites in the area or its affected downwind environs, are below 15.0 µg/m^3. (This showing must rely on three complete, consecutive calendar years of quality assured data.)

Background

The following information is taken from U.S. EPA's "Guideline on Data Handling Conventions for the PM NAAQS," U.S. EPA-454/R-99-008, April 1999.

In accordance with the CAA Amendments, three complete years of monitoring data are required to demonstrate attainment at a monitoring site. The annual $PM_{2.5}$ primary and secondary ambient air quality standards are met at an ambient air quality monitoring site when the three-year average of the annual average is less than 15.0 $\mu g/m^3$. While calculating design values, three significant digits must be carried in the computations, with final values rounded to the nearest 0.1 $\mu g/m^3$. Decimals 0.05 or greater are rounded up, and those less than 0.05 are rounded down, so that 15.049 $\mu g/m^3$ is the largest concentration that is less than, or equal to 15.0 $\mu g/m^3$. Values at or below 15.0 $\mu g/m^3$ meet the standard; values equal to or greater than 15.1 $\mu g/m^3$ exceed the standard. An area is in compliance with the annual $PM_{2.5}$ NAAQS only if every monitoring site in the area meets the NAAQS. An individual site's 3-year average of the annual average concentrations is also called the site's design value. The air quality design value for the area is the highest design value among all sites in the area.

Table 1 shows the monitoring data for 2007 – 2009 that were retrieved from the U.S. EPA AQS. The air quality design value for the area is the highest design value among all sites in the area.

Demonstration

Table 1 - Monitoring Data for the Cincinnati-Hamilton, OH-KY-IN area for 2007 – 2009

Site	County	Annual Standard			
		Year			Average
		2007	2008	2009	2007-2009
39-017-0003	Butler, OH	15.4	13.8	12.8	14.0
39-017-0016		14.9	13.8	13.1	13.9
39-017-1004 [a]		14.6			
39-025-0022	Clermont, OH	14.0	11.7	11.0	12.2
39-061-0006	Hamilton, OH	14.6	12.5	12.1	13.1
39-061-0014		16.6	15.1	13.4	15.0
39-061-0040		15.1	12.6	12.7	13.5
39-061-0042		15.9	14.4	13.7	14.7
39-061-0043 [b]		14.8	13.3		
39-061-7001		15.1	13.7	13.0	13.9
39-061-8001		16.1	14.4	13.4	14.6
39-165-0007	Warren, OH	14.0	11.9	11.7	12.5
21-037-3002 [c]	Campbell, KY	14.4	11.8	11.3	12.5
21-117-0007	Kenton, KY	14.2	12.0	11.0	12.4
	Less than 75% capture in at least one quarter				

[a] This site was terminated at the end of 2007. Based on data from available previous years, the site incidcates attainment for the PM2.5 annual standard.
2004-2006 average: 14.6ug/m3; 2005-2007 average: 15.0 ug/m3

[b] This site was discontinued at the end of 2008. Based on data from available previous years, the site indicates attainment for the PM2.5 annual standard
2006-2008 average: 14.2ug/m3

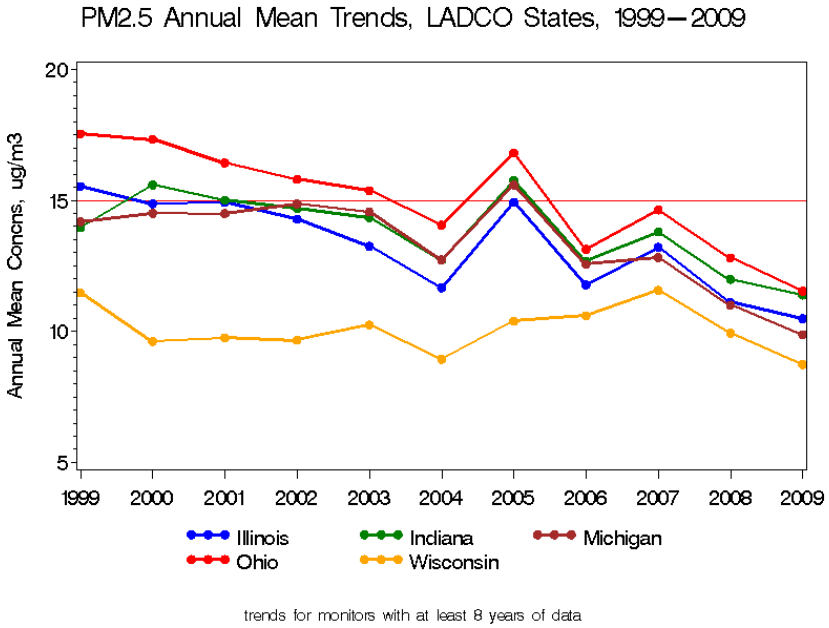
[c] This site did not start operating until 8/1/2007. All available data indicates attainment of the PM2.5 annual standard.

Source: U.S. EPA Air Quality System (AQS); http://www.epa.gov/ttn/airs/airsaqs/index.htm

The design values calculated for the Cincinnati-Hamilton area demonstrates that the annual $PM_{2.5}$ NAAQS has been attained. The area's design values have trended downward as emissions have declined due to such factors as cleaner automobiles and fuels, and controls for EGUs, at the national, regional and local level.

National monitoring for $PM_{2.5}$ began in 1999. With respect to each of the Lake Michigan Air Directors Consortium (LADCO) states, there has been a clear downward trend in design values:

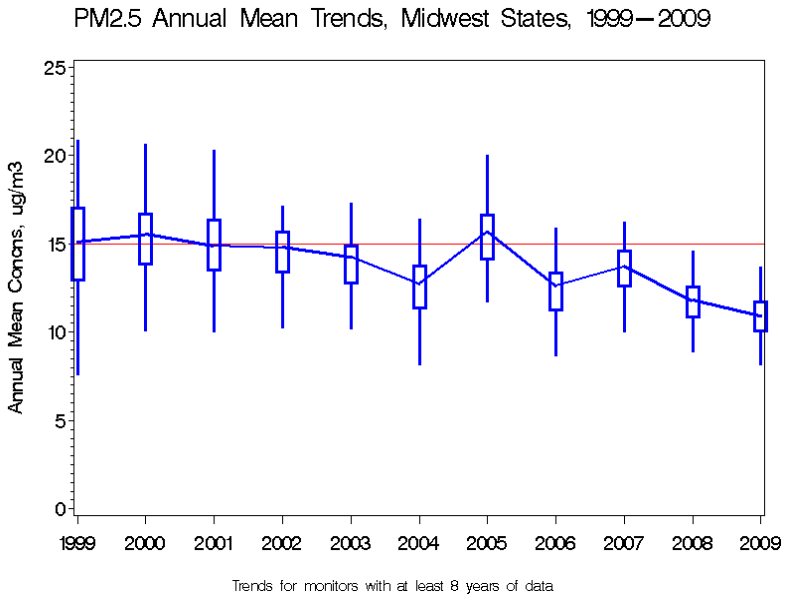
Figure 2 - $PM_{2.5}$ Annual Mean Trends LADCO States



Source: LADCO; Recent Ozone and PM2.5 Trends – Aug 26 2010.pptx

The same trend can be seen within the Midwest States as a whole:

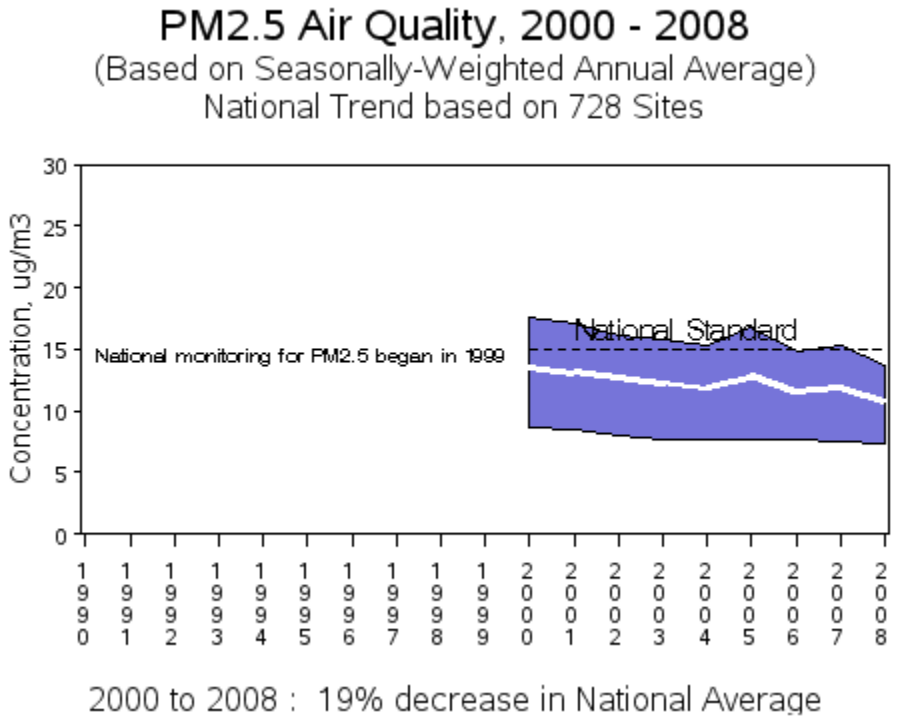
Figure 3 - $PM_{2.5}$ Annual Mean Trends Midwest States



Source: LADCO; Recent Ozone and PM25 Trends - Aug 26 2010.pptx

Design values have also trended downward nationally:

Figure 4 - $PM_{2.5}$ Annual Mean National Trends



Source: http://www.epa.gov/airtrends/pm.html

Requirement 4 of 4

A commitment that once redesignated, the state will continue to operate an appropriate monitoring network to verify the maintenance of the attainment status.

Demonstration

Ohio EPA commits to continue monitoring $PM_{2.5}$ levels at the Ohio sites indicated in Figure 1 and Table 1. Ohio EPA will consult with U.S. EPA Region V prior to making changes to the existing monitoring network, should changes become necessary in the future. Ohio EPA will continue to quality assure the monitoring data to meet the requirements of 40 CFR 58 and all other federal requirements. Connection to a central station and updates to the Ohio EPA web site[4] will provide real time availability of the data and knowledge of any exceedances. Ohio EPA will enter all data into AQS on a timely basis in accordance with federal guidelines.

4 www.epa.ohio.gov/dapc

CHAPTER FOUR

EMISSION INVENTORY

CAA Section 107(d)(3)(E)(iii)

U.S. EPA's redesignation guidance requires the submittal of a comprehensive inventory of $PM_{2.5}$ precursor emissions (primary particles (organic carbon, crustal matter, and elemental carbon), SO_2 and NO_x[5]) representative of the year when the area achieves attainment of the annual $PM_{2.5}$ air quality standard. Ohio also must demonstrate that the improvement in air quality between the year that violations occurred and the year that attainment was achieved is based on permanent and enforceable emission reductions. Other emission inventory related requirements include a projection of the emission inventory to a year at least 10 years following redesignation; a demonstration that the projected level of emissions is sufficient to maintain the annual $PM_{2.5}$ standard; and a commitment to provide future updates of the inventory to enable tracking of emission levels during the 10-year maintenance period.

The emissions inventory development and emissions projection discussion below, with the exception of the mobile (on-road) emissions inventory and projections, identifies procedures used by Ohio EPA and the LADCO regarding emissions from Ohio's portion of the counties in the Cincinnati-Hamilton area. Specific emissions data are provided for all counties, including those in Ohio, Kentucky and Indiana. Indiana and Kentucky emissions data were also obtained though the LADCO emissions inventory and projections. All of these inventories and emissions projections were prepared using similar methodologies. Ohio recognizes that revisions to the emissions data below may be necessary once Kentucky and Indiana prepare a redesignation request and maintenance plan for their portion of the nonattainment area. Mobile emissions inventories and projections for all counties were prepared by the Ohio, Kentucky, Indiana Council of Governments (OKI).

Requirement 1 of 5

A comprehensive emission inventory of $PM_{2.5}$, SO_2 and NO_x completed for the base year.

Background

The point source data are taken from Ohio's annual emissions reporting program. The 2005 periodic inventory has been identified as one of the preferred databases for SIP development and coincides with nonattainment air quality in the Cincinnati-Hamilton area.

5 VOC and NH_3 are not addressed.

Periodic inventories, which include emissions from all sectors - mobile, area, non-road, and point sources - are prepared every three years.

Demonstration

The 2005 inventory is used as the base year for the purpose of this submittal and was submitted to U.S. EPA with Ohio's $PM_{2.5}$ attainment demonstration SIP submitted on July 18, 2008 and revised on June 7, 2010. The detailed emission inventory information for the Ohio portion of the Cincinnati-Hamilton area is provided in Appendix B. Emissions of $PM_{2.5,}$ SO_2 and NO_x for 2005 are identified under Requirement Three of this Chapter.

Requirement 2 of 5

A projection of the emission inventory to a year at least 10 years following redesignation.

Background

Ohio EPA prepared a comprehensive inventory for the Ohio portion of the Cincinnati-Hamilton area including area, mobile, and point sources for $PM_{2.5}$, $S0_2$ and NO_x for base year 2005. The 2005 inventory was submitted to U.S. EPA on July 18, 2008 as part of Ohio's $PM_{2.5}$ attainment demonstration SIP for this area. The information below describes the procedures Ohio EPA used to generate the 2005 base year inventory and to develop SIP-ready modeling inventories and future year projections (Pechan Report[6]) based on a 2005 base year inventory. The report by Pechan generated future year estimates of annual emissions for each source sector using accepted growth surrogates. These inventories were provided to the LADCO and have been processed to develop average daily emissions for use in the air quality analyses. These processed modeling inventories have been identified as the correct iteration of the inventory for use in the redesignation. In this document, references to LADCO include the Midwest Regional Planning Organization. Note, the on-road mobile source sector was addressed by specific $PM_{2.5}$ and NO_x modeling as discussed below.

- Area sources were taken from the Ohio 2005 periodic inventory submitted to U.S. EPA. These projections were made from the U.S. Department of Commerce Bureau of Economic Analysis (BEA) growth factors, with some updated local information.

6 http://www.ladco.org/tech/emis/r5/reports/LADCO%202005%20Base%20Yr%20Growth%20and%20Controls%20Report_Final.pdf

- Mobile source emissions were calculated from MOVES2010 - produced emission factors. Only $PM_{2.5}$ and NO_x necessitate emissions inventory analysis. As documented in Ohio EPA's attainment demonstration SIP, Ohio EPA in consultation with U.S. EPA determined mobile sources are insignificant contributors for SO_2. Consistent with Ohio EPA's attainment demonstration, Ohio EPA continues to consider mobile source SO_2 to be an insignificant contributor to fine particles for this nonattainment area. Based on the demonstration below, SO_2 constitutes less than one percent (<1%) of the area's total SO_2 emissions in 2005, 2008, 2015 and 2021 (ranging between 0.09% and 0.31%).
- Point source information was compiled from Ohio EPA's 2005 annual emissions inventory database and the 2005 U.S. EPA Air Markets acid rain database[7].
- Biogenic emissions are not included in these summaries.
- Non-road emissions were generated using U.S. EPA's National Mobile Inventory Model (NMIM) 2002 application. To address concerns about the accuracy of some of the categories in U.S. EPA's non-road emissions model, LADCO contracted with two (2) companies to review the base data and make recommendations. One of the contractors also estimated emissions for three (3) non-road categories not included in U.S. EPA's non-road model. Emissions were estimated for aircraft, commercial marine vessels, and railroads. Recreational motorboat population and spatial surrogates (used to assign emissions to each county) were significantly updated. The populations for the construction equipment category were reviewed and updated based upon surveys completed in the Midwest, and the temporal allocation for agricultural sources also was updated.

Demonstration

On-Road Emission Estimations

In coordination with the Ohio Department of Transportation (Ohio DOT), OKI utilizes a regional travel demand forecast model to simulate traffic in the area and to forecast traffic flows for given growth expectations. The model has been validated to observed traffic volumes for the model base year 2005. The model is primarily used as a long range planning tool to evaluate the transportation system including determination of locations where additional travel capacity may be needed and to determine the infrastructure requirements necessary to meet that need. It is also used as a tool

7 http://www.epa.gov/airmarkets/acidrain

for air quality purposes to estimate the total emissions of pollution caused by vehicles in the area. The travel demand forecasting model is used to predict traffic volumes vehicle miles traveled (VMT), travel speeds, and a U.S. EPA computer program called MOVES is used to calculate emissions per mile. The product of these is the total amount of pollution emitted by the on-road vehicles for the area.

Overview

U.S.EPA published a Federal Register notice[8] of availability on March 2, 2010, to approve MOVES2010 (Motor Vehicle Emissions Simulator), hereafter referred to as MOVES. Upon publication of the Federal Register notice, MOVES became U.S. EPA's approved motor vehicle emission factor model for estimating VOCs, NO_x, CO, PM_{10} and $PM_{2.5}$ and other pollutants and precursors from cars, trucks, motorcycles, and buses by state and local agencies. MOVES is a computer program designed by the U.S. EPA to estimate air pollution emissions from mobile sources. MOVES replaces U.S. EPA's previous emissions model for on-road mobile sources, MOBILE6.2. MOVES can be used to estimate exhaust and evaporative emissions as well as brake and tire wear emissions from all types of on-road vehicles.

The CAA requires U.S. EPA to regularly update its mobile source emission models. U.S. EPA continuously collects data and measures vehicle emissions to make sure the Agency has the best possible understanding of mobile source emissions. This assessment, in turn, informs the development of U.S. EPA's mobile source emission models. MOVES represents the Agency's most up-to-date assessment of on-road mobile source emissions. MOVES also incorporates several changes to the U.S. EPA's approach to mobile source emission modeling based upon recommendations made to the Agency by the National Academy of Sciences.

U.S.EPA believes that MOVES should be used in ozone, CO, PM, and nitrogen dioxide SIP development as expeditiously as possible. The CAA requires that SIP inventories and control measures be based on the most current information and applicable models that are available when a SIP is developed.

Regarding transportation conformity, U.S. EPA and U.S. DOT intend to establish a two-year grace period before MOVES is required for new transportation conformity analyses.

8 http://www.regulations.gov/search/Regs/home.html#documentDetail?R=0900006480ab1f98

The MOVES more detailed approach (when compared with the previous MOBILE model) to modeling allows U.S. EPA to easily incorporate large amounts of in-use data from a wide variety of sources, such as data from vehicle inspection and maintenance (I/M) programs, remote sensing device (RSD) testing, certification testing, portable emission measurement systems (PEMS), etc. This approach also allows users to incorporate a variety of activity data to better estimate emission differences such as those resulting from changes to vehicle speed and acceleration patterns. MOVES has a graphical user interface which allows users to more easily set up and run the model. MOVES database-centered design provides users much greater flexibility regarding output choices. Unlike earlier models which provided emission factors in grams-per-mile in fixed output formats, MOVES output can be expressed as total mass (in tons, pounds, kilograms, or grams) or as emission factors (grams-per-mile and in some cases grams-per-vehicle). Output can be easily aggregated or disaggregated to examine emissions in a range of scales, from national emissions impacts down to the emissions impacts of individual transportation projects. The database-centered design also allows U.S. EPA to update emissions data incorporated in MOVES more easily and will allow users to incorporate a much wider array of activity data to improve estimation of local emissions. For example, the improvements in MOVES will allow project-level PM2.5 emissions to be estimated.

OKI's utilized U.S.EPA's emissions model MOVES to develop emissions factors for SO_2, NO_x and $PM_{2.5}$. Further details on the use of MOVES are found on Appendix C. Transportation system performance was estimated using the OKI Travel Demand Model Version 7.6. The model uses demographic and land use data and capacity and free-flow speed characteristics for each roadway segment in the network to produce a "loaded" highway network with forecasted traffic volumes with revised speeds based on specified speed/capacity relationships.

Travel analysis zones are the basic geographic unit for estimating travel in the OKI model. The OKI region is subdivided into 1608 traffic analysis zones to permit detail as well as manageability. A variety of socioeconomic data items are used in the OKI transportation planning process. These data are used primarily to forecast future travel patterns by serving as independent variables in OKI trip generation equations. The following categories of planning data are utilized:

- Population.
- Households.

- Household vehicles.
- Employment.
- Labor force participation.
- Area type.

The principal data requirements of the OKI travel demand forecasting model are population and employment, from these variables other characteristics including household, labor force, and personal vehicles may be derived (OKI 2030 Regional Transportation Plan 2008 Update provides a complete demographic overview of the region).

OKI utilizes both base year (2005) and future year data (2010, 2020 and 2030) in the planning process. Planning data are maintained at the Traffic Analysis Zone (TAZ) level, and originate in the 2000 Census of Population and Housing. Base year 2005 and future yare data for each variable are developed through various methods.

OKI's Travel Demand Model has been validated to observed traffic volumes for the model base year 2005. The modeling network encompasses the entire $PM_{2.5}$ nonattainment area. The modeling network also includes Greene, Miami and Montgomery counties in Ohio and the remainder of Dearborn County, Indiana. The differences between estimated vehicle miles traveled (VMT) and 2005 observed VMT is less than 1%. A highway screenline analysis compares the screenline observed and simulated traffic volume discrepancies with the Ohio Department of Transportation (ODOT) standard of maximum desirable deviation. The comparison shows that the model performs at a satisfactory level and all the errors were under the ODOT curve (OKI's 2007 report, "OKI/MVRPC Travel Demand Model Methodology/Validation Report"). For the calibration, OKI used over 3000 traffic counts collected through 2006 by the ODOT, the Kentucky Transportation Cabinet, many county and local governments, transportation engineering consultants, and OKI. These traffic counts cover nearly 50% of the links in the OKI portion of the modeling network. The methodology provides consistency with past emission inventory and conformity analysis work performed by OKI.

OKI incorporates a variety of sources of local data to both improve and confirm the accuracy of VMT, as well as other travel-related parameters. Free flow speeds used on the highway and transit networks are based on travel time studies performed locally. An OKI post-processing program uses the loaded highway network to generate VMT by hour, VMT by speed distribution, and VMT by facility type. These tables are then included as input into MOVES.

The VMT by hour tables utilize hourly traffic distribution and directional split factors for different roadway types as developed by OKI. The main source of the data was the permanent traffic counting stations located throughout the OKI region for the years of 1998-2002. These data were supplemented with data collected at coverage count stations (locations with counts taken on only one-two days). The stations were classified by area type (urban and rural) and functional classification (freeway, arterial and collector). Speeds representing various "loaded" conditions (with traffic volumes) are estimated using techniques from the 1997 Highway Capacity Manual. This permits the estimation of speeds as conditions vary from hour to hour on the different facility types throughout the region. The post-processing program performs the appropriate summation by area and roadway type as well as regional totals. OKI has also developed seasonal conversion factors to adjust traffic volumes to summer conditions. The factors were derived from local data collected at permanent traffic counting stations during 1994-1997 utilizing the average daily traffic monthly conversion factors for June, July and August.

On-Road Mobile Emission Estimations

Tables 2 through 12 contain the results of the emissions analysis for the appropriate years. All emissions estimations are expressed in tons per year (tpy).

Table 2 - Butler County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	413.970	377.640	301.16	215.76
NO_x (tpy)	10,910.37	9,803.70	6,064.61	3,757.91
SO_2 (tpy)	30.01	34.25	34.28	37.90
Annual VMT	2,469,168,490	2,598,061,793	2,792,190,918	2,966,040,396

Table 3 – Clermont County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	281.790	256.600	204.32	145.39
NO_x (tpy)	7,295.87	6,516.40	3,993.63	2,449.31
SO_2 (tpy)	20.51	23.32	23.34	25.66
Annual VMT	1,684,261,582	1,765,146,867	1,899,319,930	2,005,373,961

Table 4 – Hamilton County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	1,222.020	1,080.540	826.00	571.48
NO_x (tpy)	31,127.09	27,020.93	15,925.19	9,530.16
SO_2 (tpy)	88.85	98.30	94.43	100.82
Annual VMT	7,241,536,812	7,421,012,594	7,630,239,650	7,811,745,310

Table 5 – Warren County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	320.740	289.560	242.05	177.61
NO_x (tpy)	8,224.57	7,267.18	4,598.44	2,875.72
SO_2 (tpy)	23.54	26.57	27.77	31.58
Annual VMT	1,949,619,088	2,031,755,542	2,285,057,933	2,498,434,852

Table 6 – Dearborn County, Ohio Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	33.980	29.890	25.14	18.11
NO_x (tpy)	865.46	748.81	482.33	297.95
SO_2 (tpy)	2.45	2.69	2.87	3.19
Annual VMT	196,738,031	199,778,078	223,644,622	240,321,759

Table 7 – Summary of Ohio and Indiana Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	2,272.50	2,034.23	1,598.67	1,128.35
NO_x (tpy)	58,423.36	51,357.02	31,064.20	18,911.05
SO_2 (tpy)	165.36	185.13	182.69	199.15
Annual VMT	13,541,324,003	14,015,754,874	14,830,453,053	15,521,916,278

Table 8 – Boone County, Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	205.210	251.850	151.35	114.05
NO_x (tpy)	5,126.88	5,067.94	2,788.45	1,772.72
SO_2 (tpy)	15.91	16.71	20.67	24.37
Annual VMT	1,273,226,967	1,350,001,539	1,628,041,282	1,800,571,684

Table 9 – Campbell County, Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	120.300	146.460	82.36	60.09
NO_x (tpy)	3,041.21	2,988.33	1,570.14	985.28
SO_2 (tpy)	9.30	9.69	11.21	12.77
Annual VMT	741,790,595	774,762,718	875,774,487	936,445,352

Table 10 – Kenton County, Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	212.290	29.890	137.40	101.24
NO_x (tpy)	5,328.44	5,057.93	2,637.63	1,677.96
SO_2 (tpy)	16.24	16.34	18.62	21.48
Annual VMT	1,274,091,641	1,300,575,248	1,427,569,972	1,549,817,325

Table 11 – Summary of Kentucky Emissions Estimations for On-Road Mobile Sources

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	537.8	645.62	371.11	275.38
NO_x (tpy)	13,496.53	13,114.20	6,996.22	6,421.15
SO_2 (tpy)	41.45	42.74	50.50	72.15
Annual VMT	3,289,109,203.00	3,425,339,505.00	3,931,385,741.00	5,452,303,073.00

Table 12 – Emissions Estimations Totals for On-Road Mobile Sources for the Cincinnati-Hamilton Area

	2005	2008	2015	2021
$PM_{2.5}$ (tpy)	2,810.30	2,679.85	1,969.78	1,403.73
NO_x (tpy)	71,919.89	64,471.22	38,060.42	25,332.20
SO_2 (tpy)	206.81	227.87	233.19	271.30
Annual VMT	16,830,433,206.00	17,441,094,379.00	18,761,838,794.00	20,974,219,351.00

Motor Vehicle Emission Budget

Table 13 and Table 14 contain the motor vehicle emissions budgets for the Cincinnati-Hamilton area. For planning purposes, budgets are established for the combined Ohio and Indiana portions and for the separate Kentucky portion.

Table 13 - Mobile Vehicle Emissions Budget for Ohio and Indiana

	2015 Estimated Emissions	2015 Mobile Safety Margin Allocation*	2015 Total Mobile Budget	2021 Estimated Emissions	2021 Mobile Safety Margin Allocation*	2021 Total Mobile Budget
PM2.5 (tpy)	1598.67	79.93	1678.60	1128.35	112.84	1241.19
NOx (tpy)	31,064.20	4659.63	35,723.83	18,911.05	2836.65	21,747.71
Annual VMT	14,830,453,053	-	-	15,521,916,278	-	-

*The 5 to15 percent margin of safety was calculated by taking 5 to15 percent of the mobile source emission estimates

Table 14 - Mobile Vehicle Emissions Budget for Kentucky

	2015 Estimated Emissions	2015 Mobile Safety Margin Allocation*	2015 Total Mobile Budget	2021 Estimated Emissions	2021 Mobile Safety Margin Allocation*	2021 Total Mobile Budget
PM2.5 (tpy)	371.11	18.56	389.67	275.38	27.54	302.92
NOx (tpy)	6,996.22	1049.43	8,045.65	6,421.15	963.17	7,384.32
Annual VMT	3,931,385,741			5,452,303,073		

*The 5 to15 percent margin of safety was calculated by taking 5 to15 percent of the mobile source emission estimates

The above budgets for the Ohio and Indiana portion and for the Kentucky portion of the area, agreed upon as part of the interagency consultation process, include the emission estimates calculated for 2015 and 2021 (from Table 7 and Table 11) with an additional 5 percent margin of safety allocated for $PM_{2.5}$ in 2015, 10 percent margin of safety allocated to $PM_{2.5}$ in 2021 and 15 percent margin of safety allocated to NO_x in 2015 and 2021.

In an effort to accommodate future variations in travel demand models and VMT forecast when no change to the network is planned, Ohio EPA consulted with U.S. EPA to determine a reasonable approach to address this variation. Based on this discussion, a 5 to15 percent margin of safety allocation was agreed upon and has been added to the emissions estimates for the Ohio and Indiana portions of this nonattainment area.

All methodologies, the latest planning assumptions, and the safety margins allocations were determined through the interagency consultation process described in the Transportation Conformity Memorandum of Understanding (MOU) among OKI, Ohio DOT, and Ohio EPA.

A 5 to15 percent margin of safety is appropriate because: 1) there is an acknowledged potential variation in VMT forecast and potential estimated mobile source emissions due to expected modifications to TDM and mobile emissions models; and 2) the total decrease in emissions from all sources is sufficient to accommodate this 5 to15 percent allocation of safety margin (as defined in 40 CFR93.101[9]) to mobile sources while still continuing to maintain the total emissions in the Cincinnati-Hamilton area well below the 2008 attainment level of emissions.

The 5 to 15 percent margin of safety was calculated by taking 5 to 15 percent of the mobile source emission estimates. Safety margin, as defined by the conformity rule, looks at the total emissions from all sources in the nonattainment area. The actual allocation is less than 5 to 15 percent of the total emission reduction from all sources as can be seen from Table 44.

In summary, for all three states combined, the mobile budget safety margin allocation translates into an additional 98.49 tpy for $PM_{2.5}$ and 5,709.06 tpy for NO_x for 2015 and an additional 140.38 tpy for $PM_{2.5}$ and 3,799.82 tpy for NO_x for 2021.

9 "Safety margin" means the amount by which the total projected emissions from all sources of a given pollutant are less than the total emissions that would satisfy the applicable requirement for reasonable further progress, attainment, or maintenance.

When compared to the overall safety margin, as defined in 40 CFR 93.101, discussed under "Requirement 3 of 5" below, it is evident this allocation is significantly below the total safety margin for this area.

The current $PM_{2.5}$ and NO_x mobile budgets for the fine particle NAAQS will no longer be applicable either after the effective date of the approved redesignation or after the effective date of any U.S. EPA action approving a finding that the $PM_{2.5}$ and NO_x conformity budgets included in this submittal are adequate for transportation conformity purposes, whichever date comes first.

Finally, it is important to underline that all motor vehicle emission budgets in this Redesignation submittal, which are based on MOVES2010, will replace previous motor vehicle emission budgets on Attainment Demonstration submittals based on MOBILE6.2.

Requirement 3 of 5

A demonstration that the projected level of emissions is sufficient to maintain the $PM_{2.5}$ standard.

Background

In consultation with U.S. EPA, Ohio EPA selected the year 2021 as the maintenance year for this redesignation request. This document contains projected emissions inventories for 2015 and 2021.

Emission projections for the Cincinnati-Hamilton area were performed using the following approaches:

- As performed by OKI, mobile source emission projections are based on the U.S. EPA MOVES model. The analysis is described in more detail in Appendix C. All projections were made in accordance with "Procedures for Preparing Emissions Projections" U.S. EPA-45/4-91-019.

- Emissions inventories are required to be projected to future dates to assess the influence growth and future controls will have. LADCO has developed growth and control files for point, area, and non-road categories. These files were used to develop the future-year emissions estimates used in this document. This was done so the inventories used for redesignation are consistent with modeling performed in the future. Appendix D

contains LADCO's technical support document detailing the analysis used to project emissions (Base M[10]).

- For the Ohio portion of the Cincinnati-Hamilton area, for the 2008 attainment year, emissions were grown from the 2005 LADCO modeling inventory, using LADCO's growth factors, for all sectors except point sources (electrical generating units and non-electrical generating units). Point source emissions for 2008 were compiled from Ohio EPA's 2008 annual emissions inventory database. The 2015 interim year emissions were estimated based on the 2009 and 2018 LADCO modeling inventory, using LADCO's growth factors, for all sectors. The 2021 maintenance year is based on emissions estimates from the 2018 LADCO modeling.

The detailed inventory information for the Ohio portion of the Cincinnati-Hamilton area for 2005 is in Appendix B. Emission trends are an important gauge for continued compliance with the $PM_{2.5}$ standard. Therefore, Ohio EPA performed an initial comparison of the inventories for the base year and maintenance years. Mobile source emission inventories are described in Section 5 of Appendix B.

Sectors included in the following tables are: Electrical Generating Unit (EGU-Point); Non-Electrical Generating Unit (Non-EGU); Non-road Mobile (Non-road); Other Area (Other); Marine; Aircraft; Rail (MAR); and On-road Mobile (On-road).

Ohio EPA is identifying emissions projections for 2015 and 2021 for EGUs with implementation of the CAIR program. U.S. EPA has raised concerns regarding the CAIR program and its remand. However, as discussed below, with the proposed CAIR replacement, the Transport Rule, Ohio EPA believes these are the most appropriate and accurate future projections.

On March 10, 2004, the U.S. EPA promulgated the CAIR. Beginning in 2009, U.S. EPA's CAIR rule requires EGUs in 28 eastern states and the District of Columbia to significantly reduce emissions of NO_x and SO_2. CAIR replaced the NOx SIP Call for EGUs. The intent of the CAIR program is for national NO_x emissions to be cut from 4.5 million tons in 2004, to a cap of 1.5 million tons by 2009, and 1.3 million tons in 2018 in 28 states. States were required to submit a CAIR SIP as part of this effort. Ohio submitted a CAIR SIP which was approved by U.S. EPA on February 1, 2007.

[10] http://www.ladco.org/tech/emis/current/index.php

Revisions to the CAIR SIP were again submitted on July 15, 2009. The revised CAIR SIP was approved as a direct final action on September 25, 2009 (74 FR 48857). As a result of CAIR, U.S. EPA projects that in 2009 emissions of NO_x will decrease from a baseline of 264,000 tons per year to 93,000 tons per year while in 2010 emissions of SO_2 will decrease from a baseline of 1,373,000 tons per year to 298,000 tons per year, within Ohio. And by 2015 U.S. EPA projects emissions of NO_x will decrease to 83,000 tons per year while emissions of SO_2 will decrease to 208,000 tons per year, within Ohio[11].

On December 23, 2008, U.S. EPA's CAIR program was remanded without vacatur by the D.C. Circuit Court. As mentioned above, Ohio EPA has not incorporated these expected CAIR reductions into this redesignation request. It should also be noted that Ohio's SIP-approved NOx SIP Call program and regulations are still in place. Ohio EPA is currently in the process of revising these regulations to provide a "back stop" for the reinstatement of the NOx SIP Call program in the event the CAIR program, or an equivalent, is no longer implemented by U.S. EPA.

As can be seen in Table 15 below, Ohio has seen a significant decline in the 264,000 tons of NO_x and 1,373,000 tons of SO_2 emitted in 2005. In 2008 and 2009 facilities began preparing for and implementing control programs to address CAIR[12] and consent decrees.

Table 15 - Reductions in SO_2 and NO_x EGU Emissions Between 2008 and 2009

	SO_2			NO_x		
	2008	**2009**	**Change**	**2008**	**2009**	**Change**
Ohio	709,444	601,101	15%	235,018	96,351	59%
LADCO States	2,019,036	1,620,071	20%	702,384	393,930	44%
National	7,616,262	5,747,353	25%	2,996,287	1,990,385	34%

Source: Clean Air Markets Quarterly Emissions Tracking[13]

Significant reductions also occurred regionally and nationally as can be seen from the above. Data is also available for the first two quarters of 2010, the year SO_2 reductions are to be implemented under CAIR:

11 http://www.epa.gov/CAIR/oh.html
12 Under CAIR, NOx reductions are to occur beginning in 2009 while SO2 reductions are to occur beginning in 2010.
13 http://www.epa.gov/airmarkets/quarterlytracking.html

Table 16 – Reductions in SO_2 and NO_x EGU Emissions Between the First Half of 2008 and 2010

	SO_2			NO_x		
	2008 (1st half)	2010 (1st half)	Change	2008 (1st half)	2010 (1st half)	Change
Ohio	373,798	279,854	25%	130,598	53,187	59%
LADCO States	1,190,497	854,282	28%	419,114	220,907	47%
National	3,895,472	2,502,965	36%	1,487,179	930,148	37%

Source: Clean Air Markets Quarterly Emissions Tracking[14]

The following was reported by U.S. EPA's Clean Markets Division:

"Based on emissions monitoring data, EPA has observed substantial reductions in SO_2 emissions from 2005 to 2009 and in the first two quarters of 2010 as companies installed more controls, electric demand declined, and low natural gas prices made combined-cycle gas-fired units more competitive in several parts of the country. Thus, even after CAIR's vacatur and subsequent remand in late 2008, the controls in place generally have continued to operate, helping to drive continued progress in reducing emissions.[15]"

On July 6, 2010, U.S. EPA proposed a replacement to the CAIR program, the Transport Rule. [75 FR 45210] U.S. EPA intends to finalize the Transport Rule in time for reductions to begin in 2012. As proposed, the Transport Rule will preserve those initial reductions achieved under CAIR and provide more reductions in NO_x and SO_2 emissions in 2012 and 2014, ahead of the 2015 CAIR Phase 2.

Ohio EPA is in agreement with the analysis by U.S.EPA that the CAIR program is providing real reductions at this time, Ohio believes these reductions have assisted with $PM_{2.5}$ attainment in this nonattainment area and throughout Ohio. It is also Ohio EPA's belief that the Transport Rule, when finalized, will continue to provide the necessary reductions, and likely even greater reductions, that will be necessary for maintenance of the annual $PM_{2.5}$ standard to occur. As stated by U.S. EPA regarding the proposed Transport Rule, "the results of the air quality modeling indicate that all but one site[16] is projected to be in attainment and only one site[17] is projected to have a maintenance problem for annual PM2.5 in 2014 with the emissions reductions expected from this proposal." [75 FR 45345] Therefore, it is Ohio EPA's belief it is most appropriate to evaluate Ohio EPA's demonstration that the

14 http://www.epa.gov/airmarkets/quarterlytracking.html
15 http://www.epa.gov/airmarkets/background.htm
16 Allegheny, PA
17 Birmingham, AL

projected level of emissions is sufficient to maintain the annual $PM_{2.5}$ standard by assessing future year emissions that include the CAIR program.

Maintenance is demonstrated when the future-year (2021) projected emission totals are below the 2008 attainment year totals.

The Ohio emissions data in the tables below are based on the following data sources:

- All On-Road data source: OKI Transportation Modeling Department.
- 2008 EGU and non-EGU: Ohio EPA's 2008 annual emissions inventory database.
- All other data source: Lake Michigan Air Directors Consortium (LADCO).

Demonstration

$PM_{2.5}$

The 2005 and 2008 actual $PM_{2.5}$ emissions data below generally contains particulate fraction emissions only and not the condensable fractions as Ohio EPA did not have a consistent reporting requirement at those years. U.S. EPA Integrated Planning Model (IPM) modeling was used to generate future year EGU emissions with the CAIR program. The IPM modeling added additional $PM_{2.5}$ condensable emissions into future years. Therefore, comparing base and attainment year emissions with the future year predictions is not accurate in the IPM CAIR modeling. This step leads to a false perception of significant $PM_{2.5}$ emissions growth. Modeling performed by LADCO, without CAIR, did not incorporate added condensable fraction emissions. Although Ohio EPA has stated that it is most appropriate to evaluate future year emissions that include the CAIR program, because of this flaw it will be more accurate and appropriate for the purposes of $PM_{2.5}$ to evaluate future year emissions without the CAIR program.

Table 17 - Butler County[18], Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

18 Ohio EPA has revised the Butler County, Ohio PM2.5, NOx and SO2 Emissions Inventory (non-EGU) to incorporate the total emissions reduction credits available and used to offset the allowed emissions of a

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	15.27	16.78	15.86	15.59	1.19
Non-EGU	944.29	1045.15	1254.70	1337.03	-291.88
Non-road	185.28	158.41	109.75	66.98	91.43
Other	173.24	180.43	180.86	182.45	-2.02
MAR	31.19	27.40	16.01	6.43	20.97
On-road	413.97	377.64	301.16	215.76	161.88
TOTAL	**1763.24**	**1805.81**	**1878.34**	**1824.24**	**-18.43**

Table 18 - Clermont County, Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	648.21	532.61	651.88	711.22	-178.61
Non-EGU	7.93	3.86	6.42	7.33	-3.47
Non-road	104.54	89.84	62.51	38.56	51.28
Other	193.70	196.15	193.49	191.83	4.32
MAR	6.11	5.64	3.54	1.81	3.83
On-road	281.79	256.60	204.32	145.39	111.21
TOTAL	**1242.28**	**1084.70**	**1122.16**	**1096.14**	**-11.44**

Table 19 - Hamilton County, Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	648.64	202.88	554.65	708.74	-505.86
Non-EGU	161.88	158.14	171.28	179.45	-21.31
Non-road	355.97	307.30	218.86	141.16	166.14
Other	303.61	323.94	330.03	338.37	-14.43
MAR	42.04	37.82	23.54	11.64	26.18
On-road	1222.02	1080.54	826.00	571.48	509.06
TOTAL	**2734.16**	**2110.62**	**2124.36**	**1950.84**	**159.78**

Table 20 - Warren County, Ohio $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

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major source modified within the maintenance area that will begin operating during the maintenance period. The total emissions included in the inventory, and in all the Butler County tables below for this facility in 2015 and 2021, are 117.81 tpy PM2.5, 479.57 tpy NOx and 1209.92 tpy SO2. The emissions increase does not significantly impact the safety margin for this area or prevent the area from maintaining the standard in future years.

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	18.75	19.91	19.01	18.60	1.31
Non-road	143.72	122.20	79.69	42.68	79.52
Other	236.92	238.33	233.88	230.65	7.68
MAR	2.95	2.58	1.53	0.64	1.94
On-road	320.74	289.56	242.05	177.61	111.95
TOTAL	**723.08**	**672.58**	**576.16**	**470.18**	**202.40**

Table 21 - Dearborn County, Indiana $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	673.94	804.18	847.16	922.81	-118.63
Non-EGU	67.38	62.02	60.00	57.32	4.70
Non-road	23.96	19.91	13.34	9.07	10.84
Other	4.29	4.29	4.11	3.98	0.31
MAR					
On-road	33.98	29.89	25.14	18.11	11.78
TOTAL	**803.55**	**920.29**	**949.75**	**1011.29**	**-91.00**
*MAR emissions are included in Non-road emissions					

Table 22 - Boone County, Kentucky $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment [19]	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	76.85	76.70	80.70	83.42	-6.72
Non-EGU	58.77	68.81	84.35	98.94	-30.13
Non-road	89.15	82.90	62.42	45.30	37.60
Other	351.27	353.71	359.57	364.58	-10.87
MAR	215.61	227.62	206.01	191.23	36.39
On-road	205.21	251.85	151.35	114.05	137.80
TOTAL	**996.86**	**1061.59**	**944.40**	**897.52**	**164.07**

Table 23 - Campbell County, Kentucky $PM_{2.5}$ Emission Inventory Total for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin

19 Kentucky 2008 data is grown from the 2005 LADCO modeling inventory, using LADCO's growth factors, for all sectors, including EGUs.

EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	84.26	89.52	101.84	112.39	-22.87
Non-road	25.29	22.35	16.18	10.84	11.51
Other	200.08	201.26	200.05	199.32	1.94
MAR	55.66	53.74	41.25	31.15	22.59
On-road	120.30	146.46	82.36	60.09	86.37
TOTAL	**485.59**	**513.33**	**441.68**	**413.79**	**99.54**

Table 24 - Kenton County, Kentucky $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – Without CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	9.53	11.11	13.50	15.76	-4.65
Non-road	56.44	50.98	38.18	27.22	23.76
Other	365.74	366.69	363.77	361.65	5.04
MAR	62.64	59.63	44.85	32.76	26.87
On-road	212.29	247.31	137.40	101.24	146.07
TOTAL	**706.64**	**735.72**	**597.70**	**538.63**	**197.09**

Table 25 – Cincinnati-Hamilton Area $PM_{2.5}$ Emission Inventory Totals for Base Year 2005, Estimated 2008, and projected 2015 and 2021 (tpy) – Without CAIR

$PM_{2.5}$	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
Butler	1763.24	1805.81	1878.34	1824.24	-18.43
Clermont	1242.28	1084.70	1122.16	1096.14	-11.44
Hamilton	2734.16	2110.62	2124.36	1950.84	159.78
Warren	723.08	672.58	576.16	470.18	202.40
Dearborn	803.55	920.29	949.75	1011.29	-91.00
Boone	996.86	1061.59	944.40	897.52	164.07
Campbell	485.59	513.33	441.68	413.79	99.54
Kenton	706.64	735.72	597.70	538.63	197.09
COMBINED $PM_{2.5}$ TOTAL	**9455.40**	**8904.64**	**8634.55**	**8202.63**	**702.01**

NO_x

Table 26 - Butler County, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	743.27	856.92	343.95	124.10	732.82
Non-EGU	4367.15	3940.28	4626.45	4686.11	-745.83
Non-road	2348.42	1986.81	1228.83	572.69	1414.12
Other	796.34	807.64	811.94	817.28	-9.64
MAR	919.91	847.08	545.76	297.37	549.71
On-road	10910.37	9803.70	6064.61	3757.91	6045.79
TOTAL	**20085.46**	**18242.43**	**13621.54**	**10255.46**	**7986.97**

Table 27 - Clermont County, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	28063.56	24233.18	16491.26	10451.28	13781.90
Non-EGU	67.50	42.71	60.83	68.68	-25.97
Non-road	1218.23	1039.67	655.01	322.89	716.78
Other	612.97	619.27	620.94	623.36	-4.09
MAR	259.07	245.25	159.04	89.20	156.05
On-road	7295.87	6516.40	3993.63	2449.31	4067.09
TOTAL	**37517.20**	**32696.48**	**21980.71**	**14004.72**	**18691.76**

Table 28 - Hamilton County, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	15236.04	12372.00	7236.90	5036.15	7335.85
Non-EGU	2756.21	2652.79	2943.73	3139.37	-486.58
Non-road	4845.98	4029.63	2464.90	1098.14	2931.49
Other	1923.27	1955.47	1974.77	1995.51	-40.04
MAR	1463.80	1372.41	909.89	532.19	840.22
On-road	31127.09	27020.93	15925.19	9530.16	17490.77
TOTAL	**57352.39**	**49403.23**	**31455.38**	**21331.52**	**28071.71**

Table 29 - Warren County, Ohio NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	1024.95	1043.27	1035.29	1034.26	9.01
Non-road	1789.97	1517.53	919.21	403.56	1113.97
Other	426.57	432.28	434.26	436.82	-4.54
MAR	96.07	89.92	60.22	35.92	54.00
On-road	8224.57	7267.18	4598.44	2875.72	4391.46
TOTAL	**11562.13**	**10350.18**	**7047.42**	**4786.28**	**5563.90**

Table 30 - Dearborn County, Indiana NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	7961.30	7429.20	9862.76	11229.31	-3800.11
Non-EGU	2024.68	1979.83	1965.19	1943.22	36.61
Non-road	382.53	318.09	219.83	154.18	163.91
Other	141.37	145.42	143.39	142.90	2.52
MAR*					
On-road	865.46	748.81	482.33	297.95	450.86
TOTAL	**11375.34**	**10621.35**	**12673.50**	**13767.56**	**-3146.21**
*MAR emissions are included in Non-road emissions					

Table 31 - Boone County, Kentucky NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	3926.27	1962.59	1504.39	1308.03	654.56
Non-EGU	58.03	61.66	66.48	71.21	-9.55
Non-road	931.11	845.72	582.34	361.41	484.31
Other	1844.50	1897.28	1985.25	2063.30	-166.02
MAR	2927.85	2926.70	2310.38	1828.25	1098.45
On-road	5126.88	5067.94	2788.45	1772.72	3295.22
TOTAL	**14814.64**	**12761.89**	**9237.29**	**7404.92**	**5356.97**

Table 32 – Campbell County, Kentucky NO_x Emission Inventory Total for Base Year 2005, Estimated 2008, and Projected 2015

and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	53.68	49.52	53.81	55.21	-5.69
Non-road	284.66	261.59	189.27	128.67	132.92
Other	523.45	536.71	563.83	587.37	-50.66
MAR	1617.89	1571.87	1156.10	822.91	748.96
On-road	3041.21	2988.33	1570.14	985.28	2003.05
TOTAL	**5520.89**	**5408.02**	**3533.15**	**2579.44**	**2828.58**

Table 33 – Kenton County, Kentucky NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	19.50	20.44	21.79	23.09	-2.65
Non-road	616.67	562.88	395.18	254.61	308.27
Other	1542.27	1581.60	1654.75	1718.86	-137.26
MAR	2068.01	1999.72	1453.68	1014.71	985.01
On-road	5328.44	5057.93	2637.63	1677.96	3379.97
TOTAL	**9574.89**	**9222.57**	**6163.03**	**4689.23**	**4533.34**

Table 34 - Cincinnati-Hamilton Area NO_x Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

NOx	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
Butler	20085.46	18242.43	13621.54	10255.46	7986.97
Clermont	37517.20	32696.48	21980.71	14004.72	18691.76
Hamilton	57352.39	49403.23	31455.38	21331.52	28071.71
Warren	11562.13	10350.18	7047.42	4786.28	5563.90
Dearborn	11375.34	10621.35	12673.50	13767.56	-3146.21
Boone	14814.64	12761.89	9237.29	7404.92	5356.97
Campbell	5520.89	5408.02	3533.15	2579.44	2828.58
Kenton	9574.89	9222.57	6163.03	4689.23	4533.34
COMBINED NOx TOTAL	**167802.94**	**148706.15**	**105712.02**	**78819.13**	**69887.02**

SO_2

Table 35 - Butler County, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	1959.10	2181.63	654.49	0.00	2181.63
Non-EGU	6185.26	5442.54	6847.48	6828.13	-1385.59
Non-road	260.36	95.29	15.09	0.80	94.49
Other	224.54	221.09	209.01	198.96	22.13
MAR	80.84	79.05	62.61	49.44	29.61
On-road	30.01	34.25	34.28	37.90	-3.65
TOTAL	**8740.11**	**8053.85**	**7822.96**	**7115.23**	**938.62**

Table 36 - Clermont County, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	88876.65	42918.28	32590.92	20589.16	22329.12
Non-EGU	162.19	118.05	148.28	160.98	-42.93
Non-road	138.93	50.86	8.05	0.43	50.43
Other	164.72	162.20	151.29	142.32	19.88
MAR	22.73	15.39	5.26	0.78	14.61
On-road	20.51	23.32	23.34	25.66	-2.34
TOTAL	**89385.73**	**43288.10**	**32927.14**	**20919.33**	**22368.77**

Table 37 - Hamilton County, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	77381.13	24693.00	16390.65	7508.46	17184.54
Non-EGU	7819.40	6552.65	7739.34	8309.88	-1757.23
Non-road	474.85	174.16	28.47	1.93	172.23
Other	163.45	161.80	151.81	143.71	18.09
MAR	117.60	100.46	64.96	34.20	66.26
On-road	88.85	98.30	94.43	100.82	-2.52
TOTAL	**86045.28**	**31780.37**	**24469.66**	**16099.00**	**15681.37**

Table 38 - Warren County, Ohio SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	3.39	3.53	3.45	3.42	0.11
Non-road	23.54	26.57	27.77	31.58	-5.01
Other	140.25	138.31	131.36	125.59	12.72
MAR	8.13	7.99	6.34	5.03	2.96
On-road	208.73	76.29	11.87	1.73	74.56
TOTAL	**384.4**	**252.69**	**180.79**	**167.35**	**85.34**

Table 39 - Dearborn County, Indiana SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	46533.70	25729.10	39295.70	36843.66	-11114.56
Non-EGU	1331.15	1334.33	1335.94	1337.95	-3.62
Non-road	40.16	17.38	4.73	1.14	16.24
Other	78.72	81.02	77.64	75.69	5.33
MAR*					
On-road	2.45	2.69	2.87	3.19	-0.50
TOTAL	**47986.18**	**27164.52**	**40716.88**	**38261.63**	**-111097.11**
*MAR emissions are included in Non-road emissions					

Table 40 - Boone County, Kentucky SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	3644.98	2812.16	2617.84	2534.56	277.60
Non-EGU	16.82	17.97	19.50	21.01	-3.04
Non-road	59.56	26.45	5.98	0.51	25.94
Other	1054.33	1066.79	1093.47	1116.53	-49.74
MAR	434.71	409.48	322.39	249.85	159.63
On-road	15.91	16.71	20.67	24.37	-7.66
TOTAL	**5226.31**	**4349.56**	**4079.85**	**3946.83**	**402.73**

Table 41 - Campbell County, Kentucky SO_2 Emission Inventory Total for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	0.97	0.96	1.04	1.09	-0.13
Non-road	18.01	7.89	1.78	0.17	7.72
Other	471.77	479.14	491.66	502.75	-23.61
MAR	221.98	198.32	147.50	103.61	94.71
On-road	9.30	9.69	11.21	12.77	-3.08
TOTAL	**722.03**	**696.00**	**653.19**	**620.39**	**75.61**

Table 42 - Kenton County, Kentucky SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

Sector	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
EGU Point	0.00	0.00	0.00	0.00	0.00
Non-EGU	12.91	13.89	15.16	16.41	-2.52
Non-road	41.75	18.27	4.01	0.31	17.96
Other	1196.61	1210.42	1238.92	1263.63	-53.21
MAR	206.59	172.13	123.08	78.68	93.45
On-road	16.24	16.34	18.62	21.48	-5.14
TOTAL	**1474.10**	**1431.05**	**1399.79**	**1380.51**	**50.54**

Table 43 - Cincinnati-Hamilton Area SO_2 Emission Inventory Totals for Base Year 2005, Estimated 2008, and Projected 2015 and 2021 (tpy) – With CAIR

SO_2	2005 Base	2008 Attainment	2015 Interim	2021 Maintenance	Safety Margin
Butler	8740.11	8053.85	7822.96	7115.23	938.62
Clermont	89385.73	43288.10	32927.14	20919.33	22368.77
Hamilton	86045.28	31780.37	24469.66	16099.00	15681.37
Warren	384.04	252.69	180.79	167.35	85.34
Dearborn	47986.18	27164.52	40716.88	38261.63	-11097.11
Boone	5226.31	4349.56	4079.85	3946.83	402.73
Campbell	722.03	696.00	653.19	620.39	75.61
Kenton	1474.10	1431.05	1399.79	1380.51	50.54
COMBINED SO_2 TOTAL	**239963.78**	**117016.14**	**112250.26**	**88510.27**	**28505.87**

$PM_{2.5}$, NO_x, and SO_2

Table 44 - Cincinnati-Hamilton Area Comparison of 2008 attainment year and 2015 and 2021 projected emission estimates (tpy)

	2008 Base	2015 Interim	2015 Projected Decrease	2021 Maintenance	2021 Projected Decrease
$PM_{2.5}$	8,904.64	8,634.55	270.09	8,202.63	702.01
NO_x	148,706.15	105,712.02	42,994.13	78,819.13	69,887.02
SO_2	117,016.14	112,250.26	4,765.88	88,510.27	28,505.87

As shown in the table above (Table 44), $PM_{2.5}$ emissions in the nonattainment area are projected to decrease by 270.09 tpy in 2015 and 702.01 tpy in 2021. NO_x emissions in the nonattainment area are projected to decrease by 42,994.13 tpy in 2015 and 69,887.02 tpy in 2021. SO_2 emissions in the nonattainment area are projected to decline by 4,765.88 tpy in 2015 and 28,505.87 in 2021.

Area source emissions and, to a lesser extent, point sources show an increase due to expectations that the population will grow in this area; however, cleaner vehicles and fuels are expected to be in place in 2009 and 2018, and the Transport Rule will be implemented in 2012 and 2014 and these programs should cause an overall drop in all three pollutants emissions. Decreases from U.S. EPA rules covering Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements[20], Highway Heavy-Duty Engine Rule[21], and the Non-Road Diesel Engine Rule[22] are factored into the changes.

In addition to the above, the Miami Fort Station in Hamilton County implemented important changes in 2007. Two units, B005 (# 5-1) and B006 (# 5-2) permanently shut down effective December 31, 2007. Each were 50 megawatt coal fired boilers. In addition, units B015 (# 7) and B017 (# 8) were issued a new source review permit-to-install scrubbers, accepting a restricted SO2 allowable emissions rate that will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS) and/or Prevention of Significant Deterioration (PSD) increment violation based upon air dispersion modeling. These scrubbers began operating in April 2007 and December 2007.[23] The following summarizes Miami Fort's

20 http://www.epa.gov/fedrgstr/EPA-AIR/2000/February/Day-10/a19a.htm
21 http://www.epa.gov/fedrgstr/EPA-AIR/1997/October/Day-21/a27494.htm
22 http://www.epa.gov/fedrgstr/EPA-AIR/1998/October/Day-23/a24836.htm
23 The lower rates will be incorporated into the facility's Title V operating permit at renewal.

emissions changes from the base year (2005), to the attainment year (2008), and for 2009:

Table 45 - Miami Fort Station, Hamilton County, Emission Reductions (tpy) as Reported by Clean Air Markets Division

	SO2	NOx
2005	77,583	12,264
2008	24,693	12,371
2009	25,340	4,338

Requirement 4 of 5

A demonstration that improvement in air quality between the year violations occurred and the year attainment was achieved is based on permanent and enforceable emission reductions and not on temporary adverse economic conditions or unusually favorable meteorology.

Background

Ambient air quality data from all monitoring sites indicate that air quality met the NAAQS for $PM_{2.5}$ in 2007-2009. U.S. EPA's redesignation guidance (p 9) states: "A state may generally demonstrate maintenance of the NAAQS by either showing that future emissions of a pollutant or its precursors will not exceed the level of the attainment inventory, or by modeling to show that the future mix of sources and emissions rates will not cause a violation of the NAAQS."

Demonstration

Permanent and enforceable reductions of $PM_{2.5}$, NO_x, and SO_2 emissions have contributed to the attainment of the annual $PM_{2.5}$ standard. Some of these reductions were due to the application of tighter federal standards on new vehicles. Also Title IV of the CAA, the NO_x SIP Call, CAIR, and federal consent decrees required the reductions of SO_2 and NO_x emissions from utility sources. Reductions achieved are discussed in greater detail under Chapter Five.

Table 46 - Cincinnati-Hamilton Area Combined Comparison of 2005 base year and 2008 attainment year on-road and EGU reductions

	2005	2008
On-road $PM_{2.5}$	2810.30	2679.85
On-road NO_x	71919.89	64471.22
On-road SO_2	392.00	277.59
EGU $PM_{2.5}$	2062.91	1633.15
EGU NO_x	55930.44	46853.89
EGU SO_2	218395.56	98334.17

Requirement 5 of 5

Provisions for future annual updates of the inventory to enable tracking of the emission levels, including an annual emission statement from major sources.

Demonstration

In Ohio, major point sources in all counties are required to submit air emissions information annually, in accordance with U.S. EPA's Consolidated Emissions Reporting Rule (CERR). Ohio EPA prepares a new periodic inventory for all $PM_{2.5}$ precursor emission sectors every three years. These $PM_{2.5}$ precursor inventories will be prepared for future years as necessary to comply with the inventory reporting requirements established in the CFR. Emissions information will be compared to the 2005 base year and the 2021 projected maintenance year inventories to assess emission trends, as necessary, and to assure continued compliance with the annual $PM_{2.5}$ standard.

CHAPTER FIVE

CONTROL MEASURES AND REGULATIONS

CAA Section107 (d)(3)(E)(ii), 107(d)(3)(iv), and 107(d)(3)(E)(v)

Requirement 1 of 6

Section 172(c)(1) of the 1990 Clean Air Act Amendments requires states with nonattainment areas to implement RACM and RACT.

Background

Section 172(c)(1) of the 1990 Clean Air Act Amendments requires states with nonattainment areas to submit a SIP providing for implementation of all reasonably available control measures and expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonable available control technology).

U.S. EPA's Implementation Rule interprets this requirement in great detail. Under U.S. EPA's approach, RACT is determined as part of the broader RACM analysis and identification of all measures (for stationary, mobile, and area sources) that are technically and economically feasible, and that would collectively contribute to advancing the attainment date (i.e. by one year or more). States are required to use a combined approach to RACT and RACM, that (1) identifies potential measures that are reasonable, (2) uses modeling to identify the attainment date that is as expeditious as practicable, and (3) selects the appropriate RACT and RACM.

The Implementation Rule also provides for a presumption that in States that fulfill their CAIR emission reduction requirements, EGU compliance with CAIR is equivalent to RACM/RACT.

Demonstration

In 1972, 1980, and 1991, Ohio promulgated rules requiring reasonably available controls measures for particulate emissions from stationary sources.

Statewide RACT rules have been applied to all new sources locating in Ohio since that time. RACT requirements are incorporated into permits along with monitoring, recordkeeping, and reporting necessary to ensure ongoing compliance. Ohio EPA also has an active enforcement program to address violations discovered by field office staff. The Ohio RACT rules are found in OAC Chapter 3745-17[24].

24 http://www.epa.ohio.gov/dapc/regs/3745_17.aspx

In addition, Ohio EPA promulgated NO_x SIP Call rules (OAC Chapter 3745-14[25]), CAIR (OAC Chapter 3745-109[26]), and NO_x Reasonably Available Control Technology rules (OAC Chapter 3745-110[27]) over the past five years. Emissions from EGUs make up a significant contribution to Ohio's inventory. Beginning in 2009, Ohio implemented CAIR which has, and will, provide for significant reductions in NO_x, $PM_{2.5}$, and SO_2 until such time it is replaced by U.S. EPA's proposed Transport Rule. Then the Transport Rule will provide for even greater reductions.

As part of a larger initiative, LADCO, in consultation with two contractors, performed a series of studies exploring control measures for reducing both ozone precursors and $PM_{2.5}$ precursors in Ohio, Illinois, Indiana, Michigan, and Wisconsin area. The first consultant, MACTEC, prepared a series of white papers[28] researching different stationary source categories. The results were compiled into two reports[29]. The second consultant, Environ, investigated control options for mobile sources. The results were compiled into two reports[30]. The stationary and mobile source sectors (and associated control measures) were selected by the LADCO States based on several factors presented in the report (See Chapter 2).

Photochemical modeling was then conducted (as part of LADCO Round 4 modeling) to assess the air quality benefit of the candidate control measures and a modeling report was developed[31]. Based on the results, the LADCO project team felt it would not be possible to advance the attainment date for $PM_{2.5}$. Ohio EPA, in its attainment demonstration submitted on July 18, 2008, demonstrated (using a weight of evidence approach) that attainment would be achieved in this area by 2009. Because of a projected 2009 attainment date, it would not have been reasonably possible or practicable for Ohio to

25 http://www.epa.ohio.gov/dapc/regs/3745_14.aspx
26 http://www.epa.ohio.gov/dapc/regs/3745_109.aspx
27 http://www.epa.ohio.gov/dapc/regs/3745_110.aspx
28 http://www.ladco.org/reports/control/white_papers
29 http://www.ladco.org/reports/control/final_reports/identification_and_evaluation_of_candidate_control_measures_i_april_2005.pdf; http://www.ladco.org/reports/control/final_reports/identification_and_evaluation_of_candidate_control_measures_ii_june_2006.pdf
30 http://www.ladco.org/reports/control/final_reports/final_report_evaluation_of_candidate_mobile_source_control_measures_february_2006.pdf; http://www.ladco.org/reports/control/final_reports/final_report_evaluation_of_candidate_mobile_source_control_measures_for_ladco_states_in_2009_and_2012_march_2007.pdf
31 http://www.ladco.org/reports/control/modeling/round4_modeling.pdf

develop RACT/RACM requirements, promulgate regulations and implement a control program prior to the projected attainment date.

Requirement 2 of 6

Section 172(c)(2) of the 1990 CAA Amendments requires attainment demonstration SIPs for nonattainment areas to show reasonable further progress (RFP).

Background

U.S. EPA's Implementation Rule requires RFP only for any area which a State projects an attainment date beyond 2010. The RFP would provide emission reductions showing linear progress between 2002 and 2009. If a State demonstrates attainment will occur by 2010 or earlier, U.S. EPA considers the attainment demonstration to demonstrate achievement of RFP.

Demonstration

In Ohio's attainment demonstration submitted on July 18, 2008, Ohio demonstrated (using a weight of evidence approach) that attainment would be achieved in this area by 2009; and therefore, it was not necessary to submit a separate RFP plan.

Requirement 3 of 6

Section 172(c)(3) requires states to submit a comprehensive inventory of actual emissions.

Background

Section 172(c)(3) requires states to submit a comprehensive inventory of actual emissions in the area, including the requirement for periodic revisions as determined necessary. 40 CFR 51.1008 requires such inventory to be submitted within three years of designation and requires a baseline emission inventory for calendar year 2002 or other suitable year to be used for attainment planning.

Demonstration

The 2005 comprehensive inventory was submitted to U.S. EPA with Ohio's $PM_{2.5}$ attainment demonstration SIP submitted on July 18, 2008. It was then subsequently revised and resubmitted on June 7, 2010.

Ohio also updates its inventory in accordance with U.S. EPA's CERR rule (i.e. emissions statements). Ohio EPA submitted its emissions statement SIP on March 18, 1994 which was approved by U.S. EPA on October 13, 1995 (59 FR 51863). As discussed in Chapter 4 (Requirement 4), Ohio EPA submits, and commits to submit, emission inventories (statements) every three years.

Requirement 4 of 6

Evidence that control measures required in past $PM_{2.5}$ SIP revisions have been fully implemented.

Background

In addition to the historic RACT requirements for PM, the U.S. EPA NO_x SIP Call required 22 states to pass rules that would result in significant emission reductions from large EGUs, industrial boilers, and cement kilns in the eastern United States. Ohio passed this rule in 2001. NOx SIP Call requirements are incorporated into permits along with monitoring, recordkeeping, and reporting necessary to ensure ongoing compliance. Ohio EPA also has an active enforcement program to address violations discovered by field office staff. Compliance is tracked through the Clean Air Markets data monitoring program. Beginning in 2004, this rule accounts for a reduction of approximately 31 percent of all NO_x emissions statewide compared to previous uncontrolled years. The other 21 states also have adopted these rules.

On March 10, 2004, the U.S. EPA promulgated the CAIR. Beginning in 2009, U.S. EPA's CAIR rule requires EGUs in 28 eastern states and the District of Columbia to significantly reduce emissions of NO_x and SO_2. CAIR replaced the NOx SIP Call for EGUs. National NO_x emissions will be cut from 4.5 million tons in 2004, to a cap of 1.5 million tons by 2009, and 1.3 million tons in 2018 in 28 states. States were required to submit a CAIR SIP as part of this effort. Ohio submitted a CAIR SIP which was approved by U.S. EPA on February 1, 2007. Revisions to the CAIR SIP were again submitted on July 15, 2009. The revised CAIR SIP was approved as a direct final action on September 25, 2009 (74 FR 48857).

Demonstration

Controls for EGUs under the NO_x SIP Call formally commenced May 31, 2004. Emissions covered by this program have been generally trending downward since 1998 with larger reductions occurring in 2002 and 2003. Data taken from the U.S. EPA Clean Air Markets web site, quantify the gradual NO_x reductions that have occurred in Ohio as a result of Title IV of the 1990 CAA Amendments and the beginning of the NO_x SIP Call Rule. Ohio developed the NO_x Budget Trading Program rules in OAC Chapter 3745-14[32] in response to the SIP Call. OAC Chapter 3745-14 regulates EGUs and certain non-EGUs under a cap and trade program based on an 85 percent

32 http://www.epa.ohio.gov/dapc/regs/3745_14.aspx

reduction of NOx emissions from EGUs and a 60 percent reduction of NO_x emissions from non-EGUs, compared to historical levels. This cap was in place through 2008, at which time the CAIR program superseded it as discussed above. Requirement 3 of 5 under Chapter 4 above discussed the reductions Ohio has seen as a result of CAIR.

On April 21, 2004, U.S. EPA published Phase II of the NO_x SIP Call that establishes a budget for large (greater than 1 ton per day emissions) stationary internal combustion engines. Ohio EPA's OAC rule 3745-14-12 addresses stationary internal combustion engines, all used in natural gas pipeline transmissions. U.S. EPA approved this revision to the SIP on April 4, 2008. An 82 percent NO_x reduction from 1995 levels is anticipated. Completion of the compliance plan occurred by May 1, 2006, and the compliance demonstration began May 1, 2007.

Tier II Emission Standards for Vehicles and Gasoline Sulfur Standards

In February 2000, U.S. EPA finalized a federal rule to significantly reduce emissions from cars and light trucks, including sport utility vehicles (SUVs). Under this proposal, automakers will be required to sell cleaner cars, and refineries will be required to make cleaner, lower sulfur gasoline. This rule will apply nationwide. The federal rules will phase in between 2004 and 2009. U.S. EPA has estimated that NO_x emission reductions will be approximately 77 percent for passenger cars, 86 percent for smaller SUVs, light trucks, and minivans, and 65 to 95 percent reductions for larger SUVs, vans, and heavier trucks. The sulfur content of gasoline is estimated to be reduced by up to 90 percent. VOC emission reductions will be approximately 12 percent for passenger cars, 18 percent for smaller SUVs, light trucks, and minivans, and 15 percent for larger SUVs, vans, and heavier trucks.

Heavy-Duty Diesel Engines

In July 2000, U.S. EPA issued a final rule for Highway Heavy Duty Engines, a program which includes low-sulfur diesel fuel standards, which will be phased in from 2004 through 2007. This rule applies to heavy-duty gasoline and diesel trucks and buses. This rule will result in a 40 percent reduction in NO_x from diesel trucks and buses, a large sector of the mobile sources NO_x inventory. It also estimated the level of sulfur in highway diesel fuel will be reduced by 97 percent by mid-2006.

Clean Air Non-road Diesel Rule

In May 2004, U.S. EPA issued the Clean Air Non-road Diesel Rule. This rule applies to diesel engines used in industries such as construction, agriculture, and mining. It also contains a cleaner fuel standard similar to the highway diesel program. The new standards will cut emissions from non-road diesel engines by more than 90 percent. Non-road diesel equipment, as described in this rule, currently accounts for 47 percent of diesel particulate matter (PM) and 25 percent of NO_x from mobile sources nationwide. Sulfur levels will be reduced in non-road diesel fuel by 99 percent from current levels, from approximately 3,000 parts per million (ppm) now to 15 ppm in 2009. New engine standards take effect, based on engine horsepower, starting in 2008. Together, these rules will substantially reduce local and regional sources of $PM_{2.5}$ precursors.

Requirement 5 of 6

Acceptable provisions to provide for new source review.

Background

Ohio has a longstanding and fully implemented New Source Review (NSR) program. This is addressed in OAC Chapter 3745-31[33]. The Chapter includes provisions for the Prevention of Significant Deterioration (PSD) permitting program in OAC rules 3745-31-01 to 3745-31-20. Ohio's PSD program was conditionally approved on October 10, 2001 (66 FR 51570) and received final approval on January 22, 2003 (68FR 2909) by U.S. EPA as part of the SIP.

Demonstration

Any facility that is not listed in the 2005 emission inventory, or for the closing of which credit was taken in demonstrating attainment, will not be allowed to construct, reopen, modify, or reconstruct without meeting all applicable NSR requirements. Once the area is redesignated, Ohio EPA will implement NSR through the PSD program.

Requirement 6 of 6

Assure that all existing control measures will remain in effect after redesignation unless the State demonstrates through modeling that the standard can be maintained without one or more control measures.

Demonstration

Ohio commits to maintaining the aforementioned control measures after redesignation. Ohio hereby commits that any changes to its

33 http://www.epa.ohio.gov/dapc/regs/3745_31.aspx

rules or emission limits applicable to $PM_{2.5}$, SO_2, and NO_x as required for maintenance of the annual $PM_{2.5}$ standard in the Cincinnati-Hamilton area, will be submitted to U.S. EPA for approval as a SIP revision.

Ohio, through Ohio EPA's Legal section, has the legal authority and necessary resources to actively enforce any violations of its rules or permit provisions. After redesignation, it intends to continue enforcing all rules that relate to the emission of $PM_{2.5}$ precursors in the Cincinnati-Hamilton area.

CHAPTER SIX

CONTINGENCY MEASURES
CAA Section 107(d)(3)(E)(v)

Requirement 1 of 4
A commitment to submit a revised plan eight years after redesignation.

Demonstration
Ohio hereby commits to review its maintenance plan eight years after redesignation, as required by Section 175(A) of the CAA.

Requirement 2 of 4
A commitment to expeditiously enact and implement additional contingency control measures in response to exceeding specified predetermined levels (triggers) or in the event that future violations of the ambient standard occur.

Demonstration
Ohio hereby commits to adopt and expeditiously implement necessary corrective actions in the following circumstances:

Warning Level Response:
A warning level response shall be prompted whenever the $PM_{2.5}$ average of the weighted annual mean of 15.5 µg/m^3 occurs in a single calendar year within the maintenance area. A warning level response will consist of a study to determine whether the $PM_{2.5}$ value indicates a trend toward higher $PM_{2.5}$ values or whether emissions appear to be increasing. The study will evaluate whether the trend, if any, is likely to continue and, if so, the control measures necessary to reverse the trend taking into consideration ease and timing for implementation as well as economic and social considerations. Implementation of necessary controls in response to a warning level response trigger will take place as expeditiously as possible, but in no event later than 12 months from the conclusion of the most recent calendar year.

Should it be determined through the warning level study that action is necessary to reverse the noted trend, the procedures for control selection and implementation outlined under “action level response” shall be followed.

Action Level Response:
An action level response shall be prompted whenever a two-year average of the weighted annual means of 15.0 µg/m^3 or greater occurs within the maintenance area. A violation of the standard

(three-year average of the weighted annual means of 15.0 µg/m^3 or greater) shall also prompt an action level response. In the event that the action level is triggered and is not found to be due to an exceptional event, malfunction, or noncompliance with a permit condition or rule requirement, Ohio EPA in conjunction with the metropolitan planning organization or regional council of governments, will determine additional control measures needed to assure future attainment of the NAAQS for annual $PM_{2.5}$. In this case, measures that can be implemented in a short time will be selected in order to be in place within 18 months from the close of the calendar year that prompted the action level. Ohio EPA will also consider the timing of an action level trigger and determine if additional, significant new regulations not currently included as part of the maintenance provisions will be implemented in a timely manner and will constitute our response.

Control Measure Selection and Implementation

Adoption of any additional control measures is subject to the necessary administrative and legal process. This process will include publication of notices, an opportunity for public hearing, and other measures required by Ohio law for rulemaking.

If a new measure/control is already promulgated and scheduled to be implemented at the federal or State level, and that measure/control is determined to be sufficient to address the upward trend in air quality, additional local measures may be unnecessary. Furthermore, Ohio will submit to U.S. EPA an analysis to demonstrate the proposed measures are adequate to return the area to attainment.

Requirement 3 of 4

A list of potential contingency measures that would be implemented in such an event.

Demonstration

Contingency measures to be considered will be selected from a comprehensive list of measures deemed appropriate and effective at the time the selection is made. The selection of measures will be based on cost-effectiveness, emission reduction potential, economic and social considerations or other factors that Ohio EPA deems appropriate. Ohio EPA will solicit input from all interested and affected persons in the maintenance area prior to selecting appropriate contingency measures. Because it is not possible at this time to determine what control measures will be appropriate at an unspecified time in the future, the list of contingency measures outlined below is not exhaustive.

1) Diesel reduction emission strategies.
2) Alternative fuel (e.g., liquid propane and compressed natural gas) and diesel retrofit programs for fleet vehicle operations.
3) Tighter $PM_{2.5}$, SO_2, and NO_x emissions offsets for new and modified major sources.
4) Impact crushers located at recycle scrap yards – upgrade wet suppression.
5) Concrete manufacturing – upgrade wet suppression.
6) Additional NO_x RACT statewide.

No contingency measure shall be implemented without providing the opportunity for full public participation during which the relative costs and benefits of individual measures, at the time they are under consideration, can be fully evaluated.

Requirement 4 of 4

A list of $PM_{2.5}$, SO_2, and NO_x sources potentially subject to future additional control requirements.

Demonstration

The following is a list of $PM_{2.5}$, SO_2, and NO_x sources potentially subject to future controls.

- ICI Boilers - SO_2 and NO_x controls;
- EGUs;
- process heaters;
- internal combustion engines;
- combustion turbines;
- other sources greater than 100 tons per year;
- Fleet vehicles;
- Concrete manufacturers;
- Aggregate processing plants;

CHAPTER SEVEN

PUBLIC PARTICIPATION

Ohio published notification for a public hearing and solicitation for public comment concerning the draft redesignation petition and maintenance plan in the widely distributed county publications on October 28, 2010.

The public hearing to receive comments on the redesignation request was held on November 29, 2010 at 2:30 P.M. at the Hamilton County Department of Environmental Services, Cincinnati, Ohio. The public comment period closed on November 30, 2010. No testimony was provided at the public hearing. Comments were received during the public comment period. Appendix E includes a copy of the public notice, the transcript from the public hearing, and the response to comments.

CHAPTER EIGHT

CONCLUSIONS

The Cincinnati-Hamilton annual $PM_{2.5}$ nonattainment area has attained the 1997 annual NAAQS for $PM_{2.5}$ and complied with the applicable provisions of the 1990 Amendments to the CAA regarding redesignations of $PM_{2.5}$ nonattainment areas. Documentation to that effect is contained herein. Ohio EPA has prepared a redesignation request and maintenance plan that meet the requirements of Section 110 (a)(1) of the 1990 CAA.

Based on this presentation, the Cincinnati-Hamilton annual $PM_{2.5}$ nonattainment area meets the requirements for redesignation under the CAA and U.S. EPA guidance. Ohio has performed an analysis that shows the air quality improvements are due to permanent and enforceable measures. Furthermore, because this area is subject to significant transport of pollutants, significant regional SO_2 and NO_x reductions will ensure continued compliance (maintenance) with the standard with an increasing margin of safety.

The State of Ohio hereby requests that the Cincinnati-Hamilton annual $PM_{2.5}$ nonattainment area be redesignated to attainment simultaneously with U.S. EPA approval of the maintenance plan provisions contained herein.

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State of Ohio Environmental Protection Agency

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CERTIFIED MAIL

April 1, 2010

Cheryl L. Newton, Director
Air and Radiation Division
U.S.EPA, Region V
77 West Jackson Boulevard
Chicago, Illinois 60604

RE: 2009 SLAMS $PM_{2.5}$ and Ozone Data Certification

Dear Ms. Newton:

Please find enclosed our SLAMS Report (AMP-450, AMP-450NC and AMP-255) for calendar year 2009 as required in 40 CFR, Part 58, Section 58.15. The ambient concentration and the quality assurance data have been completely submitted to the AQS database.

The remaining criteria pollutant data will be certified within the month of April.

I certify that the Ozone and $PM_{2.5}$ data in the report are accurate to the best of our knowledge taking into consideration the quality assurance findings and only to the extent of the activities performed by Ohio EPA.

There were no incidents of air pollution that reached or exceeded levels as specified by Section 51.151 which could cause significant harm to the health of persons.

Sincerely,

Robert Hodanbosi

Robert Hodanbosi
Chief, Division of Air Pollution Control

Enclosure

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

User ID: GYE

QUICKLOOK CRITERIA PARAMETERS

Report Request ID: 787657

Report Code: AMP450

Sep. 8, 2010

GEOGRAPHIC SELECTIONS

Tribal State	County	Site	Parameter	POC	City	AQCR	UAR	CBSA	CSA	EPA Region	Method	Duration	Begin Date	End Date
39	061													
39	017													
39	025													
39	165													
21	015													
21	037													
21	117													

PROTOCOL SELECTIONS

Parameter Classification	Parameter	Method	Duration
QUICK LOOK	88101		

SELECTED OPTIONS

Option Type	Option Value
EVENTS PROCESSING	EXCLUDE REGIONALLY CONCURRED EVENTS
MERGE PDF FILES	YES

SORT ORDER

Order	Column
1	PARAMETER_CODE
2	STATE_CODE
3	COUNTY_CODE
4	SITE_ID
5	POC
6	DATES
7	EDT_ID

GLOBAL DATES

Start Date	End Date
2007	2009

APPLICABLE STANDARDS

Standard Description
PM25 24-hour 2006
PM25 Annual 2006

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Sep. 8, 2010

EXCEPTIONAL DATA TYPES

EDT	DESCRIPTION
0	NO EVENTS
1	EVENTS EXCLUDED
2	EVENTS INCLUDED
5	EVENTS WITH CONCURRENCE EXCLUDED

Note: The * indicates that the mean does
not satisfy summary criteria.

Sep. 8, 2010

PM2.5 - Local Conditions (88101) | Kentucky | Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
21-037-3002	1	0584	Highland Heights	Campbell	524A John Hill Road	2007	118	50	34.0	33.5	26.3	26.0	34.0	14.36*		5
21-037-3002	1	0584	Highland Heights	Campbell	524A John Hill Road	2008	118	119	30.5	27.3	26.1	24.4	26.1	11.83	Y	0
21-037-3002	1	0584	Highland Heights	Campbell	524A John Hill Road	2009	145	114	24.5	22.7	22.5	21.4	22.5	11.34		0
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2007	118	117	34.7	34.6	31.6	30.5	31.6	14.20		5
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2008	118	121	30.5	27.3	25.2	25.0	25.2	11.99	Y	0
21-117-0007	1	0584	Covington	Kenton	1401 DIXIE HWY, UNIVERSITY COLLEGE	2009	118	113	24.5	23.3	23.1	22.1	23.1	11.04		0

Note: The * indicates that the mean does not satisfy summary criteria.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Sep. 8, 2010

PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2007	120	118	37.8	37.1	36.8	35.3	36.8	15.41		0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2008	120	119	38.4	31.2	27.1	26.3	27.1	13.69	Y	0
39-017-0003	1	1259	Middletown	Butler	BONITA & ST JOHN	2009	000	116	31.5	27.4	25.3	24.3	25.3	12.68		0
39-017-0003	2	1259	Middletown	Butler	BONITA & ST JOHN	2008	000	58	38.1	30.9	27.3	27.2	30.9	14.32	Y	0
39-017-0003	2	1259	Middletown	Butler	BONITA & ST JOHN	2009	000	59	29.9	22.8	22.2	21.9	22.8	12.49		0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2007	120	115	38.0	36.8	34.5	34.0	34.5	14.94		0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2008	120	118	39.5	32.7	31.5	27.6	31.5	13.75	Y	0
39-017-0016	1	1259	Fairfield	Butler	400 NILLES RD.	2009	000	113	33.0	29.5	27.2	25.5	27.2	13.08		0
39-017-1004	1	1259	Middletown	Butler	HOOK FIELD AIRPORT	2007	120	112	37.6	36.9	36.4	35.5	36.4	14.63		0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2007	120	114	40.8	34.1	33.5	33.1	33.5	14.01		0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2008	120	116	25.3	24.5	23.6	23.5	23.6	11.75	Y	0
39-025-0022	1	1259	Batavia	Clermont	2400 CLERMONT CENTER DR.	2009	120	121	23.5	22.4	22.0	21.8	22.0	11.01		0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2007	120	296	40.8	39.2	38.1	37.2	34.7	14.63		0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2008	120	174	33.9	28.1	28.1	27.0	27.0	12.48	Y	0
39-061-0006	1	1259	Cincinnati	Hamilton	11590 GROOMS RD	2009	120	122	29.7	26.3	24.2	23.9	24.2	12.11		0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2007	120	109	41.5	38.1	36.5	36.2	36.5	16.59		0

Note: The * indicates that the mean does
not satisfy summary criteria.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Sep. 8, 2010

PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2008	120	119	37.7	33.3	33.0	31.7	33.0	15.12	Y	0
39-061-0014	1	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2009	120	355	34.3	33.9	29.5	29.1	27.1	13.40		0
39-061-0014	2	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2008	000	58	40.1	34.7	33.0	32.1	34.7	15.25	Y	0
39-061-0014	2	1259	Cincinnati	Hamilton	SEYMOUR & VINE ST.	2009	119	62	35.3	31.1	30.4	25.1	31.1	13.89		0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2007	120	107	41.9	35.3	34.7	33.1	34.7	15.09		0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2008	000	107	31.5	26.6	25.5	25.0	25.5	12.62	Y	0
39-061-0040	1	1259	Cincinnati	Hamilton	250 WM. HOWARD TAFT	2009	142	116	28.5	25.7	24.8	24.8	24.8	12.73		0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2007	120	110	39.2	36.3	35.9	33.6	35.9	15.90		0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2008	120	111	33.5	32.2	27.5	27.5	27.5	14.40	Y	0
39-061-0042	1	1259	Cincinnati	Hamilton	2101 W. 8TH ST.	2009	000	109	36.5	28.2	27.0	26.3	27.0	13.71		0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2007	120	116	37.2	34.0	34.0	32.6	34.0	14.85		0
39-061-0043	1	1259	Sharonville	Hamilton	3254 E. KEMPER RD.	2008	120	117	35.0	28.5	28.2	28.0	28.2	13.32	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2007	120	111	40.9	35.0	33.7	32.0	33.7	15.09		0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2008	000	112	34.2	31.9	30.3	28.9	30.3	13.74	Y	0
39-061-7001	1	1259	Norwood	Hamilton	2059 SHERMAN AVE.	2009	142	119	30.5	27.8	25.7	25.7	25.7	12.97		0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2007	120	110	37.4	36.3	35.4	32.8	35.4	16.07		0

Note: The * indicates that the mean does not satisfy summary criteria.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR QUALITY SYSTEM
QUICK LOOK REPORT (AMP450)

Sep. 8, 2010

PM2.5 - Local Conditions (88101) Ohio Micrograms/cubic meter (LC) (105)

24-HOUR

SITE ID	POC	PQAO	CITY	COUNTY	ADDRESS	YEAR	METH	#OBS	1ST MAX	2ND MAX	3RD MAX	4TH MAX	98TH PERCENTILE VALUE	WTD ARITH MEAN	CERT	EDT
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2008	120	115	37.4	31.8	31.0	30.8	31.0	14.40	Y	0
39-061-8001	1	1259	St. Bernard	Hamilton	300 MURRAY RD.	2009	120	117	30.8	30.8	28.7	28.5	28.7	13.44		0
39-165-0007	1	1259	Lebanon	Warren	416 SOUTHEAST ST.	2007	120	114	40.8	36.6	33.6	33.3	33.6	13.98		0
39-165-0007	1	1259	Lebanon	Warren	416 SOUTHEAST ST.	2008	120	118	27.7	25.7	24.2	23.3	24.2	11.92	Y	0
39-165-0007	1	1259	Lebanon	Warren	416 SOUTHEAST ST.	2009	120	119	26.5	25.6	23.6	22.4	23.6	11.70		0

Note: The * indicates that the mean does
not satisfy summary criteria.

Sep. 8, 2010

METHODS USED IN THIS REPORT

PARAMETER	METHOD CODE	COLLECTION METHOD	ANALYSIS METHOD
88101	000	MULTIPLE METHODS	MULTIPLE METHODS
88101	118	R & P Model 2025 PM2.5 Sequential w/WINS	GRAVIMETRIC
88101	119	Andersen RAAS2.5-100 PM2.5 SAM w/WINS	GRAVIMETRIC
88101	120	Andersen RAAS2.5-300 PM2.5 SEQ w/WINS	GRAVIMETRIC
88101	142	BGI Models PQ200-VSCC or PQ200A-VSCC	Gravimetric
88101	145	R & P Model 2025 PM-2.5 Sequential Air Sample:	Gravimetric

Note: The * indicates that the mean does
not satisfy summary criteria.

Sep. 8, 2010

PQAOS USED IN THIS REPORT

PQAO	AGENCY DESCRIPTION
0584	Kentucky Division For Air Quality
1259	Hamilton County Department Of Environmental Services

Note: The * indicates that the mean does not satisfy summary criteria.

OHIO
2005 Base Year PM2.5 SIP Inventory

Ohio Environmental Protection Agency
Lazarus Government Center
50 West Town Street, Suite 700
Columbus Ohio 43215

Prepared by Ohio EPA

Division of Air Pollution Control
Emissions Inventory Unit
February 2008

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Figure

2005 Base Year PM2.5 SIP Inventory for Ohio

Introduction

The State of Ohio has a number of counties with air quality data showing non-attainment for the following $PM_{2.5}$ standard:

- Annual Standard = 15.0 ug/m3

The Clean Air Act Amendments (CAAA) requires all states to revise and submit State Implementation Plans (SIP) for areas which are classified as non-attainment of the 1997 Fine Particle ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS). The Federal Register (Vol. 72, No. 79/ Wednesday, April 25, 2007) provides the emissions inventory rules and regulations for the $PM_{2.5}$ Clean Air Fine Particle implementation rule. An electronic version of the document can be found at http://www.epa.gov/fedrgstr/EPA-AIR/2007/April/Day-25/a6347.pdf.

As part of the designation of non-attainment areas for $PM_{2.5}$ standards, a new attainment demonstration SIP will be necessary. A key element in the overall SIP planning process is the need for an updated emissions inventory. This document presents the 2005 Base Year Particulate SIP Emissions Inventory for Ohio as required by the CAAA. It includes emissions for point, area, on-road mobile and non-road mobile for the State of Ohio.

This technical report documents the procedures and the methodologies that were used in the development of daily emissions for all counties in Ohio. This report describes the following:

1. Identification of stationary and mobile sources included in the inventory;
2. Sources of data, and data collection methods used in the development of the inventory;
3. Methods and procedures used to estimate emissions; and
4. Assumptions considered in the development of the emissions inventories.

The intent of this report is to describe how the inventory was prepared, and what information was considered in the inventory development.

This document is comprised of 5 sections, one section for each inventory type. The biogenic inventory is not being discussed in this document because Ohio EPA did not participate in the generation of this inventory. Lake Michigan Air Directors Consortium (LADCO) ran EPA's BEIS model in the Emission Modeling System (EMS) to generate Summer Weekday emissions for VOC and NOx.

SECTION 1

POINT SOURCES

Emissions and source specific data for point sources are collected for the 2005 base-year SIP inventory by the Ohio Environmental Protection Agency (Ohio EPA.) The primary source of data for point sources is facility reported STARShip files. STARShip is a software package developed by Ohio EPA, Division of Air Pollution Control (DAPC), to assist the regulated community in preparing and submitting a variety of electronic permit applications and reports to the DAPC. These data are reported by the Title V facilities annually as part of the emissions fee/inventory process conducted by Ohio EPA and include emissions, process rates, operating schedules, emissions control data and other relevant information.

The STARShip files are electronically transferred to the DAPC and stored into the Division's Oracle database, STARS. The files are reviewed by the local air agencies and Ohio EPA district and central office staff. After review, the data are imported into Excel and linked with an Access® database to further process the information into the federally approved National Emission Inventory (NEI) database format in version 3.0. The files are quality assured again using the United States Environmental Protection Agency's (U.S.EPA) QA/QC software for format and content. The data is finally submitted to LADCO for emissions processing through the Emissions Modeling System. The State provided inventory for Electric Generating Units (EGU) is replaced with the Federal EGU inventory. The EGU inventory is compiled by U.S. EPA's Acid Rain Program. It is based on facility reported emissions as measured by continuous emissions monitors. In conclusion, the final point source inventory is a hybrid of the federal EGU inventory and the state provided non-EGU units.

A major distinction typically made in emissions inventories is that between point and area sources. In this inventory, point sources are sources for which individual records are maintained for that source. Such records are maintained for all Ohio Title V facilities (706 facilities statewide). The area source inventory accounts for facilities from non-Title V facilities and calculates emissions information using surrogate emissions factors based on energy usage, population, employment records, or other reliable data. A more detailed discussion of the area source inventory is provided in Section 2. The point source inventory described herein is considered to be the most current and accurate source of emissions data available for 2005.

1.1 Point Source Process Emissions

Ohio EPA defines point source process emissions as those which occur at an identifiable Title V stationary stack or vent. Point source emissions not emitted from discrete stacks or vents are termed fugitive emissions and are discussed in Section 1.2.

1.1.1 Source Identification and Data Collection

The sources to be included in the 2005 base year inventory are identified using the Title V STARS database. Facility production and emissions data are included in this database. This information is facility-reported actual 2005 emissions.

1.1.2 Non-reactive VOC Emissions Adjustments

This section is primarily applicable for VOC pollutants. Sources are required to identify emissions of photochemically non-reactive Volatile Organic Compounds (VOC.) Based upon this information, those emissions have been specifically excluded from the 2005 base line inventory in accordance with U.S. EPA's "Recommended Policy on the Control of Volatile Organic Compounds." A complete list of the compounds that U.S. EPA has identified as being photochemically non-reactive, and therefore not included in the inventory, are listed below:

- Methane
- Ethane
- Methylene chloride
- Methyl chloroform
- Trichlorofluoromethane (CFC-11)
- Dichlorodifluoromethane (CFC-12)
- Chlorodifluoromethane (CFC-22)
- Trifluoromethane (HFC-23)
- Chlorofluoromethance (HCFC-31)
- Difluoromethane (HFC-32)
- Decafluoropentane (HFC-43-10mee)
- Ethylfluoride (HFC-161)
- Trichlorotrifluoroethane (CFC-113)
- Dichlorotetrafluoroethane (CFC-114)
- Chloropentafluoroethane (CFC-115)
- 2,2-Dichloro-1,1,1-trifluoroethane (HCFC-123)
- 1,1,2-Trifluoroethane (HCFC-123a)
- 2-Chloro-1,1,1,2-tetrafluoroethane (HCFC-124)
- Pentafluoroethane (HFC-125)
- 1,1,2,2,-Tetrafluoroethane (HFC-134)
- 1,1,1,2-Tetrafluoroethane (HFC-134a)
- 1,1-Dichloro-1-fluoroethane (HCFC-141b)
- 1-Chloro-1,1,-difluoroethane (HCFC-142b)
- 1,1,1-Trifluoroethane (HFC-143a)
- Fluoroethane (HCFC-151a)
- 1,1-Difluoroethane (HFC-152a)
- Pentafluoropropane (HFC-225ca)
- Pentafluoropropane (HFC-225cb)
- Hexafluoropropane (HFC-236ea)
- Hexafluoropropane (HFC-236fa)
- Pentafluoropropane (HFC-245ca)
- Pentafluoropropane (HFC-245ea)
- Pentafluoropropane (HFC-245eb)

- Pentafluoropropane (HFC-245fa)
- Pentafluorobutane (HFC-365mfc)
- Parachlorobenzotrifluoride (PCBTF)
- Methoxybutane
- Nonaflourobutane
- Heptafluoropropane ($(CF_3)_2CFCF_2OCH_3$)
- Heptafluoropropane ($(CF_3)CFCF_2OC_2H_5$)
- Perchloroethylene
- Cyclic, branched or linear completely methylated siloxanes
- Methyl acetate
- Volatile methyl siloxanes
- Acetone

1.1.3 Emissions Estimation Methodologies

Since source reported actual annual emissions are used in the 2005 base year inventory, no estimation methods are necessary. The reports are provided to LADCO in National Emissions Inventory Input Format (NIF) 3.0 format. LADCO imported and processed the NIF files in EMS and applied temporal and spatial profiles to the annual emissions to calculate weekday emissions rates. The final point source inventory is split into two separate reports, the Electric Generating Units (EGU) which is the U.S. EPA inventory for electric generating units and the non-EGU which is the state inventory minus the EGU units.

1.2 Point Source Fugitive Emissions

Another type of emissions data which is required to be filed from point sources is fugitive emissions. Before 1990, fugitive emissions were categorized as area sources due to the lack of detailed information available for fugitive sources. However, since these emissions are now electronically reported in the State's ORACLE database, STARS, these emissions can be classified as point sources.

1.3 References

Getting Started: Emissions Inventory Methods for PM2.5 U.S. Environmental Protection Agency, Research Triangle Park, NC, September, 1999.

Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Qaulity Standards (NAAQS) and Regional Haze Regulations, Office of Air Quality Planning & Standards Research, Triangle Park, NC. November 2005.

Compilation of Air Pollution Emission Factors, Fourth Edition and Supplements, AP-42. U.S. Environmental Protection Agency, Research Triangle Park, NC, September 1985.

Preparing 2002 Regional PM2.5 Emissions QAQPS PM Inventory Conference Inventory Conference San Diego, 2003.

Documentation for the 2002 Electric Generating Unit National Emissions Inventory (NEI). Eastern research group, Inc., 1600 Perimeter Park Drive, Morrisville, NC 27560 and E.H. Pechan and Associates, Inc., 5528–B Hempstead Way

SECTION 2

AREA SOURCES

Area sources are sources which are typically small, individual, numerous, and have not been inventoried as specific point, mobile, or biogenic sources. For inventory purposes, they are grouped with other like sources into categories that allow emissions to be calculated collectively using one methodology. Since area sources are traditionally defined at the county level, most methods are designed to estimate area source emissions at the county level.

Ohio EPA has either used published Emission Inventory Improvement Program (EIIP)[6] methodologies or selected other methodologies which are shared by other states. The decision of which methodology to use was largely based on Ohio's data availability. Data which was not available on a county-level is estimated by assigning a percentage of the state's total activity to each county based on the state's population or employment information. If Ohio county specific activity data is available through Ohio EPA or other State Agencies, that data is used rather than allocating activity by percentage. Table 2-1 lists the sources which emit $PM_{2.5}$, NO_x and SO_2 along with the respective EFs used to calculate each pollutant.

Table 2-1 Categories in the 2005 $PM_{2.5}$ SIP Area Source inventory

Area Source	NO_x	$PM_{2.5}$	SO_2	Section
Commercial Natural Gas Combustion	94 lb/MMSCF	7.6 lb/MMSCF	0.6 lb/MMSCF	2.1
Industrial Distillate Oil Combustion	20 lb/E3gal fuel	0.25 lb/E3gal fuel	42.6 lb/E3gal fuel	2.2
Industrial Residual Oil Combustion	55 lb/E3gal fuel	4.67 lb/E3gal fuel	157 lb/E3gal fuel	2.2
Industrial Natural Gas Combustion	94 lb/MMSCF	7.6 lb/MMSCF	0.6 lb/MMSCF	2.2
Residential Coal Combustion	9.1 Lb/Ton Coal	3.8 Lb/Ton Coal	31 Lb/Ton Coal	2.3
Residential Distillate Oil Combustion	18 lb/E3gal fuel	0.83 lb/E3gal fuel	42.6 lb/E3gal fuel	2.3
Residential Natural Gas Combustion	94 lb/MMSCF	7.6 lb/MMSCF	0.6 lb/MMSCF	2.3
Residential LPG Combustion	13 lb/E3gal fuel	0.17 lb/E3gal fuel	0.1 lb/E3gal fuel	2.3
Human Cremation	1.01E+01 lb/Ton cremated	0.0637 lb/Ton cremated	NA	2.4
Structure Fires	1.4 Lb/Ton burned	10.8 Lb/Ton burned	NA	2.5
Outdoor Wood Boilers	2.8 Lb/Ton	2.76E+1 Lb/Ton	4 E-1 Lb/Ton	2.6

Residential Wood Combustion				
Non-Certified	2.80E+00 lb/Ton	3.06E+01 lb/Ton	4.00E-01 lb/Ton	2.3
Non-Catalytic	2.80E+00 lb/Ton	1.96E+01 lb/Ton	4.00E-01 lb/Ton	
Catalytic	2.00E+00 lb/Ton	2.04E+01 lb/Ton	4.00E-01 lb/Ton	

2.1 Commercial Natural Gas Combustion (SCC 2103006000)

The 2005 total state-level commercial sector energy consumption is obtained from the Energy Information Administration (EIA)'s State Energy Data System (SEDS), and apportioned per county based on population[4]. Emissions factors are given in table 2-1. The area source emissions are calculated based on an adjusted value by subtracting the emissions due to point sources.

2.2 Industrial Fuel Combustion

Industrial Distillate Oil Combustion (SCC 2102004000)

Ohio's fuel consumption is apportioned per county based on the county's population[4]. The area source NO_X emissions are calculated and adjusted by subtracting the emissions due to point sources. A heating value of 140 MMBTU/1000 Gal is used and 84,408 thousand gallons are consumed in 2005. [MMBTU stand for Million British Thermal Units]. Emissions factors are given in table 2-1.

SO_2 emissions were calculated using EF 42.6 Lb/1000 Gal. PM_{10} and $PM_{2.5}$ emissions are calculated using 1Lb/1000 Gal and 0.25 Lb/1000 Gal respectively. All Factors are obtained from AP-42[19]

Industrial Residual Oil Combustion (SCC 2102005000)

Ohio's fuel consumption is apportioned per county based on the county's population[4]. The area source NO_X emissions are calculated and adjusted by subtracting the emissions due to point sources. 54,652 thousand gallons[14] are consumed in 2005 and a heating value of 140 MMBTU/1000 Gal is used. The SO_2 emissions are calculated using EF 157 Lb/1000 Gal. PM_{10} and $PM_{2.5}$ emissions are calculated using 7.17 Lb/1000 Gal and 4.67 Lb/1000 Gal respectively. All factors are obtained from AP-42[19]

Industrial Natural Gas Combustion (SCC 2102006000)

Ohio's fuel consumption is apportioned per county based on the county's population[4]. The area source NO_X emissions are calculated and adjusted by subtracting the emissions due to point sources. 293,857 MMCF[14] are consumed in 2005. The SO_2

emissions are calculated using EF 0.6 Lb/MMBTU. The PM_{10} and $PM_{2.5}$ emissions are calculated using 7.6 Lb/MMBTU. All factors were obtained from AP-42[19]

2.3 Residential Fuel Combustion

Residential Coal Combustion (SCC 2104001000)

Ohio's household consumption of coal is apportioned per county based on county population[4]. NO_X emissions are calculated using EF of 9.1 of coal. The SO_2 emissions are calculated using EF 31Lb/1000 Gal. The PM_{10} and $PM_{2.5}$ emissions are calculated using 6.2Lb/Ton and 3.8 Lb/Ton respectively. All factors were obtained from AP-42[19]

Residential Distillate Oil Combustion (SCC 2104004000)

Ohio's household consumption of distillate oil is apportioned per county based on county population[4]. NO_X emissions are calculated using EF of 18 lb/1000 gallons distillate fuel respectively. A heating value of 140 MMBTU/1000 Gal is used. The SO_2 emissions are calculated using EF 42.6 Lb/1000 Gal. The PM_{10} and $PM_{2.5}$ emissions are calculated using 1.08Lb/1000 Gal and 0.83 Lb/1000 Gal respectively. All factors are obtained from AP-42[19]

Residential Liquid Petroleum Gas Combustion (LPG) (SCC 2104007000)

Ohio's household consumption of LPG is apportioned per county based on county population[4]. NO_X emissions are calculated using EF of 13 lb/1000 gallons LPG. The SO_2 emissions are calculated using EF 0.1 Lb/1000 Gal. The PM_{10} and $PM_{2.5}$ emissions are calculated using 0.17Lb/1000 Gal. All factors are obtained from AP-42[19]

Residential Natural Gas Combustion (SCC 2104006010)

Ohio's household consumption of LPG is apportioned per county based on county population[4]. NO_X emissions are calculated using EF of 94 lb/MMSCF. MMSCF stands for Million Standard Cubic Feet. This source also emits SO_2 emissions which are calculated using EF 0.6 Lb/MMBTU. The PM_{10} and $PM_{2.5}$ emissions are calculated using 7.6Lb/MMBTU. All factors are obtained from AP-42[19]

Residential Wood Combustion

NO_X emissions from this area source are calculated for seven types of residential heating units that utilize wood for fuel. They are listed below with the appropriate SCC:

Fireplaces without inserts	2104008001
Fireplaces with inserts catalytic (non-U.S. EPA cert)	2104008002
Fireplaces with inserts non -catalytic	2104008003
Fireplaces with inserts catalytic (U.S. EPA cert)	2104008004
Wood stoves – Conventional	2104008010
Woodstoves – Catalytic	2104008030
Wood stoves – Non catalytic	2104008050

The number of Ohio homes with fireplaces are adjusted for those that burn wood. The following assumptions are applied to those adjusted homes:

92 percent of wood combusted in non-certified units
5.7 percent of wood combusted in non-catalytic units
2.3 percent of wood combusted in catalytic units

A state consumption value is applied which is apportioned to each county based on its population[4]. Table 2-2 shows the EF used for each of the seven types of indoor wood burners which make-up this category:

Table 2-2 Emission Factors Used for Wood Burners

SCC	**2104008002**	**2104008003**	**2104008004**	
SCC	**2104008010**	**2104008050**	**2104008030**	
SCC	**2104008001**			
RAPIDS Code	**Non-Certified**	**Non-Catalytic**	**Catalytic**	**Units**
SO_2	4.00E-01	4.00E-01	4.00E-01	Lb/ton
NO_X	2.80E+00	2.80E+00	2.00E+00	Lb/ton
$PM_{2.5}$	3.06E+01	1.96E+01	2.04E+01	Lb/ton

To avoid double counting of wood consumption for fuel, this category is adjusted by subtracting the wood consumption from OWB to allow this category to account only for indoor wood burning emissions.

Residential Wood combustion also emits SO_2 which is calculated using EF 0.4 Lb/Ton EF. The $PM_{2.5}$ emissions are calculated using EF as shown in table 2-2. All factors are obtained from AP-42[19]

2.4 Human Cremation (SCC 2810060200)

Not all Ohio counties possess a crematory so only those counties with crematories are used to calculate the number of cremations and their resulting NOx emissions. The 2005 cremation data is obtained from the Ohio Department of Health, Vital Statistics[17]. It is estimated that 3% of deaths occur outside the State of Ohio with no available data to account for their disposition at the time this area source is being calculated. Therefore, those deaths are not accounted for in this category.
The methodology does not offer an EF for NOx for this category nor is NOx required to be calculated for this area source. Ohio feels that it is a combustion source and NOx needs to be included in the inventory along with the other combustion sources. Through its Permits-to-Install for human cremation, Ohio has selected a NOx EF of 10.13lb/ton cremated to calculate emissions from this area source.

This source also emits PM, PM_{10}, and $PM_{2.5}$ emissions which are calculated using EF 0.1 Lb/Ton, 0.071Lb/Ton and, 0.0637 Lb/Ton respectively. All factors are obtained from AP-42[19]

2.5 Structure Fires (SCC 2810030000)

The Structure Fires category includes residential and commercial fires resulting from unintentional actions. Intentional fires, forest and wildfires, agricultural, and vehicle burning are not included in this area source. The State Fire Marshall Office, Fire Prevention Bureau[15] provided data on the number of structure fires per county in 2005.

This area source is considered a combustion source for NO_X emissions which are calculated using EF 1.4 lb/ton burned. The residential and commercial structures fires for each county are tabulated and a fuel loading of 1.15 Ton/fire is applied. This source also emits PM, PM_{10}, and $PM_{2.5}$ emissions which are calculated using EF 10.8 Lb/Ton. This factor was obtained from AP-42[19]

2.6 Outdoor Wood Boilers (SCC 2104008070)

Outdoor Wood Boilers (OWB), are also known as outdoor water stoves and outdoor wood furnaces, are used as outdoor residential heaters. These boilers have wood burning fireboxes surrounded by a water reservoir vented by a chimney stack. The combustion of the wood in the firebox heats the water in the surrounding reservoir and the heated water is pumped to the residence. OWB units can also supply residential hot water. The water capacity ranges from 60 gallons to 764 gallons. The operational design creates long periods where the fire smolders and creosote is formed[13].

When the water circulating through the furnace reaches an upper set point, the air supply to the fire is cut-off, cooling the fire so the water will not overheat. The furnace operates in this "idle" mode until the water temperature hits a lower set point and the air supply is re-established. The OWB may be in idle mode far longer than in operating mode. This type of operating causes very poor combustion and heavy foul smoke. Most of the smoke emitted is fine condensed organic material that does not burn under cool, oxygen starved conditions. In addition, many owners burn green wood full of moisture which also causes poor combustion[12]. The smoke created from these outdoor wood burning units can contain several pollutants that are harmful to breathe, including fine particle pollution such as $PM_{2.5}$[11] in addition to NOx (research assisted by Deborah Lucas, DAPC intern, 2007)

This new area source category has many unknowns and variables associated with it and Ohio does not possess accurate OWB unit sales data available to calculate emissions on the county level. Therefore, several assumptions are made in agreement with the Great Lake States in order to formulate a homogeneous inventory for the region.

The assumptions are as follows:

- 100% of wood combusted in non-certified units.
- OWB units to be 90% in rural counties and 10% in urban counties
- 11.68 cords of wood consumption per unit per year (includes heating efficiency of 30-40%)
- 5 months heating season = 3650 hours (24/7)
- $PM_{2.5}$ emissions factor (g/kg wood) =13.82 (Average of indoor and outdoor) or 27.64 lb/ton of wood

The agreed upon methodology requires that total number of OWB sold in Ohio be apportioned to each county based on rural or urban designation while observing the 9:1 ratio in area sales. The guesstimated factors (see above) are applied to calculate the emissions from this outdoor wood burner. Total emissions obtained from this category are subtracted from the Residential Wood Combustion category to allow for accurate emissions from the indoor wood burning units.

2.7 References

1. Documentation For the 2002 Non-Point Source National Emission Inventory For CAPS and HAPS. U.S. Environmental Protection Agency. Emissions Factor and inventory Group. E.H Pechan and Associates, Inc. January 2004.

2. United States Census Bureau. Population Division. **http://eire.census.gov/popest/data/counties/tables/CO-EST2002/CO-EST2002-01-39.php** (Accessed 2003)

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4. Ohio Department of Development, Office of Strategic Research. *Population Projects by Age and Sex: 2005-2030.* http://www.odod.ohio.gov/research/files/p200.htm (Accessed August 2006)

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6. Environmental Protection Agency (EPA). STAPPA-ALAPCO-EPA Emission Inventory Improvement Program (EIIP). Volume III - Area Sources Preferred and Alternative Methods. November 1996.

7. Documentation for the Draft 1999 National Emissions Inventory (Version 3.0) for Criteria Air Pollutants and Ammonia. Area Sources. E. H. Pechan & Associates, Inc. March 3, 2003

8. U.S. Environmental Protection Agency, STAPPA-ALAPCO-EPA Emission Inventory Improvement Program (EIIP), Volume III - Area Sources Preferred and Alternative Methods, Chapter 8. September 1997.

9. Spreadsheet formulation provided by “Buzz” David Asselmeier, Air Quality Planning Section, Inventory Group, Springfield, Illinois.

10. Environmental Protection Agency (EPA). STAPPA-ALAPCO-EPA Emission Inventory Improvement Program (EIIP). Volume III - Area Sources Preferred and Alternative Methods. May 1997.

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12. (Washington State, Department of Ecology) viewed on Feb 8th, 2007 [http://www.ecy.wa.gov/programs/air/AOP_Permits/Boiler/Outdoor_Boilers_home.html]

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15. State Fire Marshal Office. Fire Prevention Bureau, Columbus, Ohio. http://www.com.state.oh.us/odoc/sfm/firecont.htm (Accessed 2003)

16. Documentation for the Draft 1999 National Emissions Inventory (Version 3.0) For Criteria Air Pollutants and Ammonia. Area Sources. E. H. Pechan & Associates, Inc. March 3, 2003

17. Ohio Department of Health, Vital Statistics

18. Environmental Protection Agency. STAPPA-ALAPCO-EPA Emission Inventory Improvement Program (EIIP). Volume X – Emissions Projections. December 1999. http://www.epa.gov/ttn/chief/eiip/techreport/volume10/x01.pdf (Accessed 2/2007)

19. Environmental Protection Agency. AP-42. http://www.epa.gov/ttn/chief/ap42/

SECTION 3

NON-ROAD SOURCES

The non-road inventory is generated regionally by running U.S. EPA's National Mobile Inventory Model (NMIM) model. The Wisconsin Department of Natural Resources undertook the responsibility of customizing the NMIM input files and submitting the output file in NIF format to LADCO and U.S. EPA. LADCO processed the NMIM files in their emissions model and generated daily emissions rates. Grant Heatherington from the Wisconsin Department of Natural Resources provided the following descriptions…

The National Mobile Inventory Model (NMIM) developed by USEPA was used to estimate emissions for all other non-road mobile categories. NMIM consolidates non-road mobile emissions and on-road emissions modeling into a single modeling system. Only the non-road emissions modeling portion of NMIM was used in the development of this emission's inventory. NMIM uses the USEPA's NONROAD model to calculate non-road mobile emissions. The basic NONROAD algorithm for calculating emissions uses base year equipment populations, average load factors, available engine powers, activity hours and emission factors. Before NMIM was run, modifications and additions were made to the NMIM input data.

a. Added emission factors for diesel tampers/rammers provided by E.H. Pechan & Associates, Inc. Diesel tampers/rammers are a type of construction equipment.

b. Revised $PM_{2.5}$ ratios in SCC table to correctly calculate $PM_{2.5}$ diesel emissions. This error was introduced with NMIM2005 and didn't exist in NMIM2004.

c. Revised gasoline parameters using updates provided by the states and E.H. Pechan & Associates, Inc. Gasoline parameters include Reid Vapor Pressure (RVP), oxygenate content and sulfur content.

The NMIM NEI NIF files are on the LADCO ftp site at:
ftp://ftp.airtoxics.org/inv2005/nonroad/NMIM/Base_L_ph2/2005/

Revised NMIM2005 Input Data

Emission Factor Data

All States: Pechan revised the brake specific fuel consumption (BSFC) emission factor data to include diesel tampers/rammers (2270002006). The revised NMIM file is saved as revBSFC.EMF.

Population Data

For 26000.pop, replaced default file supplied with NMIM2005 with 26000_rev_NMIM05.pop that contains revised construction data missing from 26000.pop external file provided with NMIM2005. This Michigan construction data should have been added with the other LADCO states modified construction data but was overlooked.

SCC Data

The default SCC table of NCD20060201 is replaced by a version that contains corrections to the PM25fac field that earlier NCDs contained (i.e. changed from 0.92 to 0.97 for diesel non-road equipment) in NONROAD2004.

Fuel Data

LADCO States: Pechan revised four tables (countyyear, countyyearmonth, datasource and gasoline) in the National County Database (NCD) used by NMIM to incorporate new fuel data. AIR revised gasoline characteristics per instructions from the states. Also, gasoline characteristic revisions for 2005 provided by states were incorporated. Additional revisions were incorporated into 2002 data for non-road Stage 2 controls. Depending on the year being modeled, different versions of the revised tables are used. Also, the countynrfile, countyyear and datasource tables were revised to reference the new activity, allocation, growth, population and seasonality files described above. NCD tables with names ending in "def" are default versions of the table. See table below for the appropriate versions of the tables for the selected years.

Non-LADCO States: The countynrfile, countyyear and datasource tables were revised to reference the new activity, allocation and seasonality files described above. See table below for the appropriate versions of the tables for the selected years.

Table 3-1 NMIM National County Database Tables for Specific Years and States

States	**Years**	
	1999 (WI only)	**2002, 05, 07, 08, 09, 12 and 18**
LADCO states	countynrfile_NMIM05_rev, countyyear_NMIM05_rev, countyyearmonth_NMIM05_w_05_12_18_rev, datasource_NMIM05_rev, gasoline_NMIM05_def SCC_NCD20060201_rev (used when NCD20060201 is used)	countynrfile_NMIM05_rev, countyyear_NMIM05_rev , countyyearmonth_NMIM05_w_05_12_18_rev, datasource_NMIM05_rev, gasoline_NMIM05_w_05_12_18_rev SCC_NCD20060201_rev (used when NCD20060201 is used)

SECTION 4

ON-ROAD SOURCES

A mobile source of air pollution is a self-propelled or portable emitter of air pollutants, and mobile source emissions are those generated by the engines or motors that power such sources. Most mobile sources, except jet or turboprop aircraft, are powered by internal combustion (IC) piston engines, and nearly all use liquid fuels.

Gaseous fuels, such as compressed natural gas (CNG) or liquefied petroleum gas (LPG), had only a very small fraction of the motor fuel market in Ohio in 2005. Solid fuels have not been used by mobile sources in significant amounts since railroads retired their coal-powered steam locomotives in the 1950s.

4.1 Categories of Mobile Sources

For inventory and planning purposes, mobile sources are divided into two major categories.

1. **On-highway** mobile sources (usually referred to as **on-road**), e.g., motor vehicles such as cars, vans, trucks, buses and motorcycles used for transportation of goods and passengers on roads and streets

2. **Off-highway** (usually referred to as **non-road**) mobile sources including:

    - Modes of powered transportation that do not use roads, such as aircraft, trains, ships and boats, and motor vehicles used off-road.

    - Self-propelled or portable motorized machines or equipment not used for transportation, ranging from construction equipment and farm tractors to lawnmowers and hand-held power weed choppers.

Mobile Sources: All on-road mobile sources are self-propelled.

Non-road Mobile Sources: Some non-road mobile sources (e.g., farm tractors), are self-propelled, but many non-road sources are not. A gasoline-powered chain saw is a familiar example of a non-self-propelled non-road mobile source.

Stationary Sources: Not all movable or portable emission sources are mobile sources, however. A small truck-portable cement or hot-mix asphalt plant, for example, may be set up near a construction or road-building site. Such plants are classified as stationary sources, not mobile sources for two reasons: (1) they may operate for weeks or months at a single location, and (2) the trucks that move the plants do not supply power for them.

NOTE: Not all Internal Combustion engines (IC) or turbine engines are mobile sources. Fixed IC engines, such as those that power pipeline compressors or standby generators in electricity plants and elsewhere, are also classified as stationary sources.

4.1.1 Categories and Components of Mobile Source Emissions

There are three categories of mobile source emissions:

- *Exhaust or tailpipe emissions*, which result from the combustion of fuel in the source's engine

- *Evaporative emissions*, which result from evaporation of fuel from the engine or its fuel system

- *Refueling emissions*

Exhaust Emissions: Are the result of fuel combustion and occur only when the engine is running.

Evaporative emissions: Are Volatile Organic Compound (VOC) based only and are continuously emitted from an engine's fuel system, whether the engine is running or not. Gasoline is a very volatile fuel, so total VOC emissions from gasoline powered vehicles have a large evaporative component. Diesel and jet fuels are of very low volatility, so evaporative emissions from diesel and turbine engines are a much smaller part of their total VOC emissions. Evaporative emissions for CNG or LPG powered vehicles are negligible because their fuel tanks and systems are of necessity, sealed.

Evaporative and exhaust VOC emissions can be calculated separately for most mobile source categories. Evaporative emissions do not include VOC emissions that occur during refueling.

Refueling Emissions: These emissions are the third category of mobile source emissions. Refueling emissions are entirely VOC. Although they result from the evaporation of fuel, they are distinct from, and not directly related to, evaporative emissions as defined above.

Refueling emissions have two subcomponents:

- Displacement emissions. These occur when new fuel is transferred into a partly filled tank--be it a service station storage tank, a portable fuel container (gas can), or a vehicle or engine's fuel tank; displacing the air in the tank and forcing that vapor-rich air out the inlet pipe or other vent. There are two stages of displacement emissions:

    - "**Stage I**" emissions occur when the underground storage tanks at a service station are being refilled;

- "**Stage II**" emissions occur when a motor vehicle (or gas can) is being refueled.

  NOTE: These emissions are covered in, "Area Sources," section 3.6.

- Spill emissions. These occur when drops of fuel drip or splash on the ground during or after refueling and evaporate away.

4.2 Ohio On-Road Mobile Source Inventory

The inventory of on-road mobile source emissions was developed in conjunction with the Ohio Department of Transportation (ODOT), Lake Michigan Air Director's Consortium (LADCO), United States Environmental Protection Agency (USEPA), and the Ohio EPA (OEPA). Estimates of the amounts of NOx and VOC are reported by county in tons per day. Emissions are reported for a typical ozone season weekday in the summer of 2005.

4.2.1 Emission Inventories Developed with MOBILE6 Model

MOBILE6 Overview:

MOBILE6 is a computer program that estimates hydrocarbon (HC), carbon monoxide (CO), oxides of nitrogen (NO_x), exhaust particulate matter (which consists of several components), tire wear particulate matter, brake wear particulate matter, sulfur dioxide (SO_2), ammonia (NH_3), six hazardous air pollutant (HAP), and carbon dioxide (CO_2) emission factors for gasoline-fueled and diesel highway motor vehicles, and for certain specialized vehicles such as natural-gas-fueled or electric vehicles that may replace them. The program uses the calculation procedures presented in technical reports posted on EPA's MOBILE6 Web page http://www.epa.gov/otaq/models.htm.

MOBILE6 emission factor estimates depend on various conditions, such as ambient temperatures, travel speeds, operating modes, fuel volatility, and mileage accrual rates. Many of the variables affecting vehicle emissions can be specified by the user. MOBILE6 will estimate emission factors for any calendar year between 1952 and 2050, inclusive. Vehicles from the 25 most recent model years are considered to be in operation in each calendar year.

4.2.2 MOBILE6 Defaults:

MOBILE6 includes default values for a wide range of conditions that affect emissions. These defaults are designed to represent "national average" input data values. Users who desire a more precise estimate of local emissions can substitute information that more specifically reflects local conditions. Use of local input data will be particularly common when the local emission inventory is to be constructed from separate

estimates of roadways, geographic areas, or times of day, in which fleet or traffic conditions vary considerably.

A list of MOBILE6 input parameters is provided below. Most of these inputs are optional because the model will supply default values unless **alternate data** are provided.

4.2.3 MOBILE6 Input Parameters

- Calendar year
- Month (January, July)
- Hourly Temperature
- Altitude (high, low)
- Weekend/weekday
- Fuel characteristics (Reid vapor pressure, sulfur content, oxygenate content, etc.)
- Humidity and solar load
- Registration (age) distribution by vehicle class
- Annual mileage accumulation by vehicle class
- Diesel sales fractions by vehicle class and model year
- Average speed distribution by hour and roadway
- Distribution of vehicle miles traveled by roadway type
- Engine starts per day by vehicle class and distribution by hour
- Engine start soak time distribution by hour
- Trip end distribution by hour
- Average trip length distribution
- Hot soak duration
- Distribution of vehicle miles traveled by vehicle class
- Full, partial, and multiple diurnal distribution by hour
- Inspection and maintenance (I/M) program description
- Anti-tampering inspection program description
- Stage II refueling emissions inspection program description
- Natural gas vehicle fractions
- HC species output
- Particle size cutoff
- Emissions factors for PM and HAP
- Output format specifications and selections

4.2.4 MOBILE6 References

The following publications provide much of the guidance for the preparation of the on-highway inventory.

EPA-450/4-81-026d (Revised), now EPA/450-R-92-009, *Procedures for Emission Inventory Preparation, Volume IV: Mobile Sources*, December 1992. Hereafter, "Procedures Vol. IV". The 1992 version is still the definitive document on

inventories. If a previous edition is referred to, the fact will be noted as, for example, "the 1989 Procedures Vol. IV" or "Volume IV, 1989 edition".

EPA420-R-03-010, *User's Guide to MOBILE6.1 and MOBILE6.2: Mobile Source Emission Factor Model*, August 2003. This is the User's Guide for the official MOBILE6.2.03 on-highway mobile source emission factor model and will usually be referred to as the M6.2 (or simply M6) User's Guide (UG). The M6 model in its various versions was developed and published by Assessment & Modeling Division (AMD) of the National Vehicle & Fuels Emissions Laboratory (NVFEL) in Ann Arbor, Michigan. The NVFEL is part of USEPA Office of Transportation & Air Quality (OTAQ), formerly the Office of Mobile Sources (OMS).

Technical Guidance on the Use of MOBILE6 for Emission Inventory Preparation, August 2004. Hereafter, the M6 "Technical Guidance [Document]" or "TGD". The TGD is the primary source of guidance on M6 inputs and an invaluable adjunct to the M6 User's Guide.

USEPA document "Frequently Asked Questions on MOBILE6", 16 January 2002. Hereafter, [M6] "FAQ". This document was published along with the M6 TGD.

USEPA memo, "Policy Guidance on the Use of MOBILE6 for SIP Development and Transportation Conformity", dated 18 January 2002, from John Seitz, Director of OAQPS, and Margo Oge, Director of OTAQ, to Regional Air Division Directors.

4.3 Ohio's Alternate Data for MOBILE6

Alternative data is state-specific data that is used in the Mobile6 runs. Using local data is preferred to using the default data in Mobile6. Efforts are made to collect as much local data as possible.

4.3.1 Vehicle Registration Distribution by Age

Overview:

The vehicle age distribution determines the fraction of vehicles operating within each emissions control requirement standard and the deterioration of the emission control technology.

Emission rates vary widely between new and older vehicles. Thus, even small changes in fleet age, particularly for older vehicles, may result in large changes in emission totals.

The MOBILE6 model requires estimates of a distribution of registered vehicles by age and vehicle category for current and future years. MOBILE6 default values were developed using national level vehicle registration data by age and class for July 1, 1996. EPA developed a methodology to convert the July 1, 1996 registration profile into a general registration distribution by age and by vehicle category for some 6 composite (gasoline and diesel) vehicle types plus motorcycles. To project future changes, EPA evaluated general sales growth and vehicle scrappage trends for the total light-duty vehicle in-use fleet and the total heavy-duty vehicle in-use fleet, and made minor adjustments, where possible, to reflect some of the differences between vehicle categories.

Description: The MOBILE6 model requires estimates of a distribution of registered vehicles by age and vehicle category for current and future years. OEPA chose to use local vehicle registration data provided by the Ohio Bureau of Motor Vehicles (BMV) which was sent to the Lake Michigan Air Directors Consortium (LADCO) to develop these inputs. LADCO then contracted with a subcontractor to breakout the age distribution data from the Vehicle Identification Numbers (VIN).

Note: It was learned during the course of this inventory that there were some discrepancies in the age distribution data. But it was too large of a project to reevaluate the data prior to this inventory. This will be corrected in the next inventory (2008).

Method Applicability: This approach is most applicable in areas where there are significant differences in the local vehicle fleet age distribution relative to the national average.

Data Sources and Procedures: This approach involves using local vehicle registration data. This is typically available at the county level, but may also be applied using statewide data from the state motor vehicle registration office. The fleet age should be representative of the vehicle fleet over the small urban or rural area under question.

Advantages:

- Uses locally specific registration data, which is likely more representative of the local area than the national default.
- Requires minimal additional resources, particularly if data is readily available at the county or local level from the State department of motor vehicle registration.
- Recommended by EPA and generally is encouraged as a preferred approach over the national default approach.

4.3.2 Daily Vehicle Miles Traveled (DVMT)

Overview:

In coordination with Ohio Metropolitan Planning Organizations (MPOs), the Ohio Department of Transportation (ODOT) provided Daily Vehicle Miles Traveled (DVMT) data and travel demand model (TDM) data. TDM data will be covered in another section. Because TDM results are used by the state and MPOs to forecast traffic for a variety of reasons, undergo rigorous calibration and validation checks, and are sensitive to roadway capacity/travel time improvements, the TDMs are considered the best tool for emissions forecasting. Therefore, the DVMT data discussed in this section is not used directly for all areas of Ohio. In counties where it is not used directly it is used for making rough emissions estimates where models do not exist or where time prohibits the use of TDMs. DVMT is a simple mechanism to measure how much traffic is flowing along a roadway during an average 24 hour period. This simple formula multiplies Average Annual Daily Traffic (AADT) by the length of the roadway. For example; if a roadway is 2 miles in length and the AADT is 4000 vehicles per day the DVMT would be computed by multiplying 2*4,000 =8,000 or 8,000 DVMT.

County-By-County DVMT is computed using the State of Ohio, Department of Transportation's Roadway Information Files and the annual Highway Performance Monitoring System (HPMS) Summary Reports. DVMT's are computed for all of the Federal Functional Class (FC) categories within each of Ohio's 88 counties.

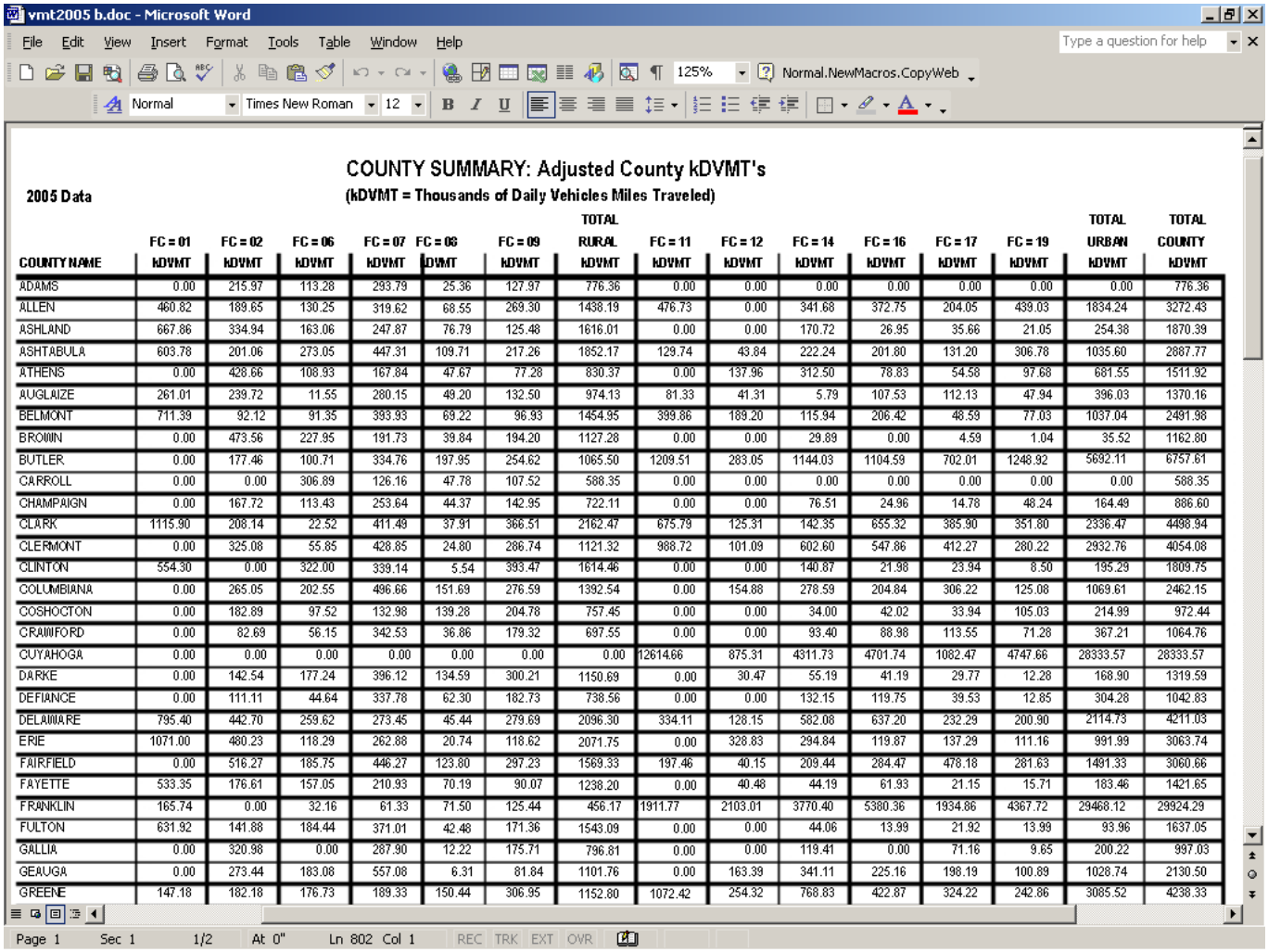
The AADT and Roadway length information provides a very accurate estimate of statewide total DVMT for The State Highway System (Interstate, US and State Routes). County total DVMT are consistent and considered a good source of county level DVMT for countywide emissions estimates. For roadways that are not part of the State Highway System, various representative counts were used, such as: railroad crossing counts, HPMS Sample Section Counts, etc. All traffic count data that was not collected during the current year has had statewide growth factors applied to account for systematic growth.

Given the previously mentioned methodologies, the DVMT data is more accurate on roads functionally classified as collector or above.

Table 4-1 Federal Functional Class Categories:

01 - Rural Interstate	11 - Urban Interstate
02 - Rural Principal Arterial	12 - Urban Freeway & Expressway
06 - Rural Minor Arterial	14 - Urban Principal Arterial
07 - Rural Major Collector	16 - Urban Minor Arterial
08 - Rural Minor Collector	17 - Urban Collector
09 - Rural Local	19 - Urban Local

Table 4-2 DVMT County Summary:



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COUNTY SUMMARY: Adjusted County kDVMT's

2005 Data

(kDVMT = Thousands of Daily Vehicles Miles Traveled)

COUNTY NAME	FC = 01 kDVMT	FC = 02 kDVMT	FC = 06 kDVMT	FC = 07 kDVMT	FC = 08 kDVMT	FC = 09 kDVMT	TOTAL RURAL kDVMT	FC = 11 kDVMT	FC = 12 kDVMT	FC = 14 kDVMT	FC = 16 kDVMT	FC = 17 kDVMT	FC = 19 kDVMT	TOTAL URBAN kDVMT	TOTAL COUNTY kDVMT
ADAMS	0.00	215.97	113.28	293.79	25.36	127.97	776.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	776.36
ALLEN	460.82	189.65	130.25	319.62	68.55	269.30	1438.19	476.73	0.00	341.68	372.75	204.05	439.03	1834.24	3272.43
ASHLAND	667.86	334.94	163.06	247.87	76.79	125.48	1616.01	0.00	0.00	170.72	26.95	35.66	21.05	254.38	1870.39
ASHTABULA	603.78	201.06	273.05	447.31	109.71	217.26	1852.17	129.74	43.84	222.24	201.80	131.20	306.78	1035.60	2887.77
ATHENS	0.00	428.66	108.93	167.84	47.67	77.28	830.37	0.00	137.96	312.50	78.83	54.58	97.68	681.55	1511.92
AUGLAIZE	261.01	239.72	11.55	280.15	49.20	132.50	974.13	81.33	41.31	5.79	107.53	112.13	47.94	396.03	1370.16
BELMONT	711.39	92.12	91.35	393.93	69.22	96.93	1454.95	399.86	189.20	115.94	206.42	48.59	77.03	1037.04	2491.98
BROWN	0.00	473.56	227.95	191.73	39.84	194.20	1127.28	0.00	0.00	29.89	0.00	4.59	1.04	35.52	1162.80
BUTLER	0.00	177.46	100.71	334.76	197.95	254.62	1065.50	1209.51	283.05	1144.03	1104.59	702.01	1248.92	5692.11	6757.61
CARROLL	0.00	0.00	306.89	126.16	47.78	107.52	588.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	588.35
CHAMPAIGN	0.00	167.72	113.43	253.64	44.37	142.95	722.11	0.00	0.00	76.51	24.96	14.78	48.24	164.49	886.60
CLARK	1115.90	208.14	22.52	411.49	37.91	366.51	2162.47	675.79	125.31	142.35	655.32	385.90	351.80	2336.47	4498.94
CLERMONT	0.00	325.08	55.85	428.85	24.80	286.74	1121.32	988.72	101.09	602.60	547.86	412.27	280.22	2932.76	4054.08
CLINTON	554.30	0.00	322.00	339.14	5.54	393.47	1614.46	0.00	0.00	140.87	21.98	23.94	8.50	195.29	1809.75
COLUMBIANA	0.00	265.05	202.55	496.66	151.69	276.59	1392.54	0.00	154.88	278.59	204.84	306.22	125.08	1069.61	2462.15
COSHOCTON	0.00	182.89	97.52	132.98	139.28	204.78	757.45	0.00	0.00	34.00	42.02	33.94	105.03	214.99	972.44
CRAWFORD	0.00	82.69	56.15	342.53	36.86	179.32	697.55	0.00	0.00	93.40	88.98	113.55	71.28	367.21	1064.76
CUYAHOGA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12614.66	875.31	4311.73	4701.74	1082.47	4747.66	28333.57	28333.57
DARKE	0.00	142.54	177.24	396.12	134.59	300.21	1150.69	0.00	30.47	55.19	41.19	29.77	12.28	168.90	1319.59
DEFIANCE	0.00	111.11	44.64	337.78	62.30	182.73	738.56	0.00	0.00	132.15	119.75	39.53	12.85	304.28	1042.83
DELAWARE	795.40	442.70	259.62	273.45	45.44	279.69	2096.30	334.11	128.15	582.08	637.20	232.29	200.90	2114.73	4211.03
ERIE	1071.00	480.23	118.29	262.88	20.74	118.62	2071.75	0.00	328.83	294.84	119.87	137.29	111.16	991.99	3063.74
FAIRFIELD	0.00	516.27	185.75	446.27	123.80	297.23	1569.33	197.46	40.15	209.44	284.47	478.18	281.63	1491.33	3060.66
FAYETTE	533.35	176.61	157.05	210.93	70.19	90.07	1238.20	0.00	40.48	44.19	61.93	21.15	15.71	183.46	1421.65
FRANKLIN	165.74	0.00	32.16	61.33	71.50	125.44	456.17	1911.77	2103.01	3770.40	5380.36	1934.86	4367.72	29468.12	29924.29
FULTON	631.92	141.88	184.44	371.01	42.48	171.36	1543.09	0.00	0.00	44.06	13.99	21.92	13.99	93.96	1637.05
GALLIA	0.00	320.98	0.00	287.90	12.22	175.71	796.81	0.00	0.00	119.41	0.00	71.16	9.65	200.22	997.03
GEAUGA	0.00	273.44	183.08	557.08	6.31	81.84	1101.76	0.00	163.39	341.11	225.16	198.19	100.89	1028.74	2130.50
GREENE	147.18	182.18	176.73	189.33	150.44	306.95	1152.80	1072.42	254.32	768.83	422.87	324.22	242.86	3085.52	4238.33

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For PDF web based tables of 2005 DVMT by county see:

http://www.dot.state.oh.us/techservsite/availpro/Road_%20Infor/KDVMT/vmt2005.pdf

Disclaimer by ODOT:

The above PDF web based tables contain the State of Ohio's adjusted county DVMT's and road mileage for the years 1990 - 2005. Please be aware that the numbers are estimates only. The factoring process used annual, estimated, and statewide ADT (Average Daily Traffic) growth factors, derived from the output of a limited number of traffic counting stations around the state. Although the growth factors are available by functional class, they are more reliable for major roads such as interstates or expressways, which are relatively well-sampled, than for local roads or collectors. The numbers also do no allow for periodic, large-scale functional reclassification actions

which reassign selected roads or road segments from one functional class to another.

The Ohio Department of Transportation therefore does not warrant the accuracy, completeness, or reliability of these estimates for your research. We also do not assume responsibility for any incorrectness that may occur.

4.3.3 VMT From Travel Demand Models (TDM)

Overview:

Travel demand forecast modeling is performed by the Ohio Metropolitan Planning Organizations (MPOs) and ODOT for a multitude of purposes including the preparation of regional emissions estimates. The ODOT Office of Technical Services' Modeling & Forecasting Section recommends that Ohio's TDMs and ODOT's conformity analysis methods be used to establish the roadway mobile source portion of Ohio's SIP budget to assure consistent methods are used for transportation conformity analysis and budgets. Therefore, ODOT provided both MPO regional TDM runs and statewide TDM runs with associated data to OEPA and LADCO. The ODOT provided model run data for years 2002, 2005, 2009, 2012, and 2018.

Data provided included loaded networks in both CSV format and GIS shape files, trip end summaries, zone boundary GIS shape files, intra-zonal trip VMT estimates, and VMT summaries for each of the loaded networks. Additional post processing data was provided including but not limited to metadata describing the loaded networks, Hourly distribution by functional class, speed profiles, day of week / weekend / monthly car and truck traffic profiles, 2009 & 2018 VMT RPO data sets, statewide VMT growth rates for local traffic, and a 2005 VMT summary comparison spreadsheet. It should be noted that among other things, the loaded TDM Networks contain distance and daily volumes from which VMT is computed.

Network volumes are post processed to estimate VMT by hour of day. The hourly volumes and capacity, posted speed limit, and type of roadway for each roadway segment are then used to estimate average hourly speeds needed for MOBILE6 based emissions estimates. Modeling by segment by hour of day in this way makes emissions estimates more sensitive to the effects of roadway improvements. This allows transportation planners to evaluate the relative emissions affect of improvements to individual roadways as well as packages of improvements and the entire set of planned roadway improvement projects air quality impacts of construction programs.

4.3.4 Speed Distribution Profiles

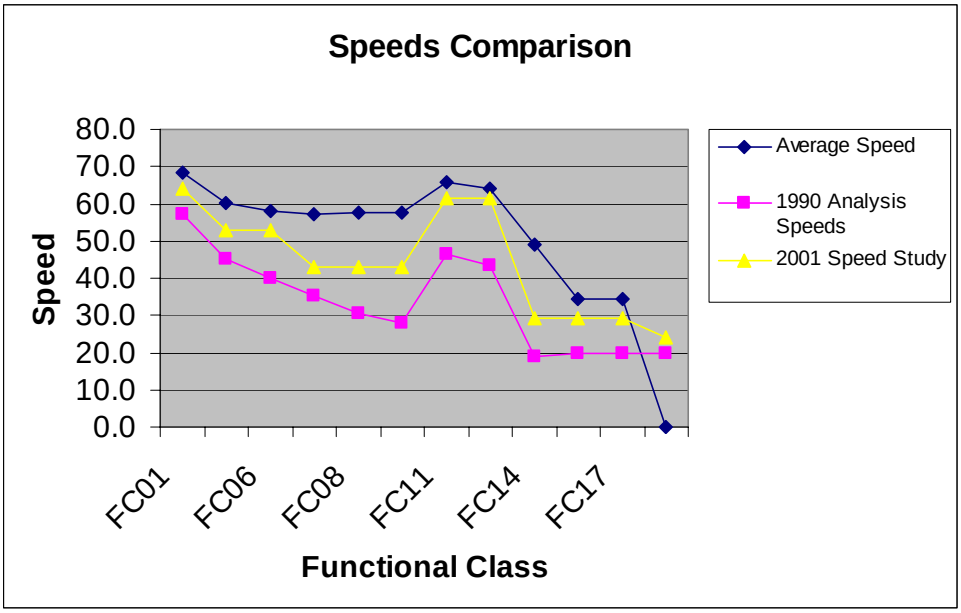
Overview:

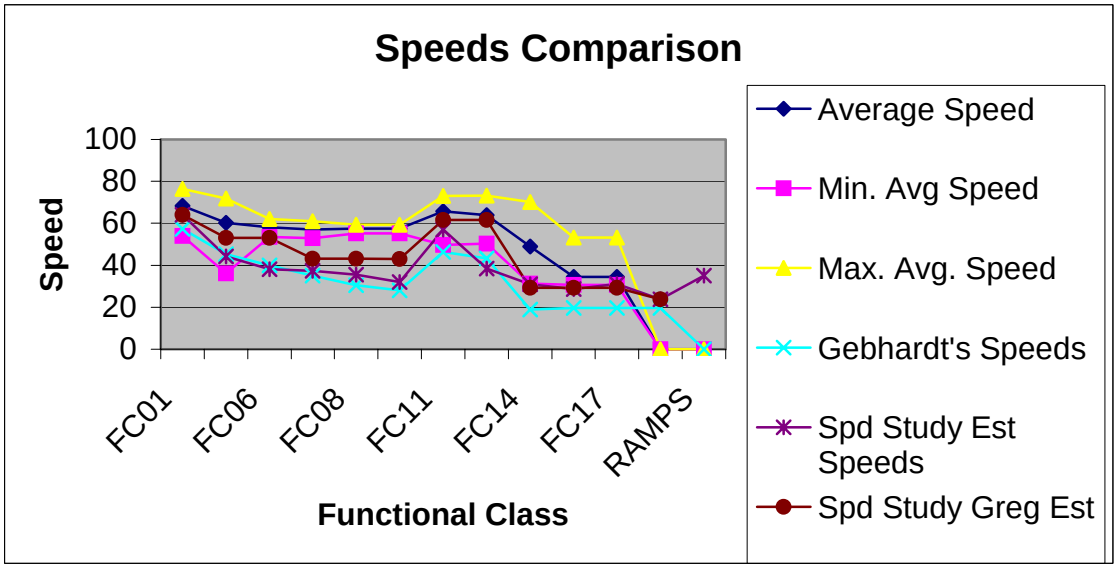
ODOT provided speed distribution profiles to LADCO. A couple of different sets of speed distribution profiles were provided to OEPA and LADCO for their use, a table of space mean speeds by functional class for use with DVMTs and link group speed curves for post processing travel demand model traffic forecasts. Both sets of speed profiles are based on the same speed study conducted by ODOT. The speed study is documented in "Statewide Travel Time Study, May 2001 by Greg Giaimo, Ohio Department of Transportation". When OEPA asked for speeds for use with MOBILE6 for development of CERR, ODOT provided a set of speeds based on that statewide travel time study. Those speeds are documented in a technical memorandum titled "Estimation of Average Speed by Functional Class for MOBILE6 Runs" dated 5/27/2004. Readers should refer to those documents for the details. Here the contents of the technical memo, Estimated Average Speed by Functional Class, are summarized.

Space Mean Speeds by Functional Class for Use with County Level DVMT, HPMS:

The memo states that the speeds which the Ohio Department of Transportation (ODOT) had been using prior to that date, 2004, for air quality analysis estimates based on County DVMT summaries, were developed by a former ODOT employee for addressing the one (1) hour standards conformity rules established due to 1990 emissions exceedances. No documentation was found in ODOT's files on the origin of these average speed values or how they were estimated. In addition, EPA has requirements for using latest planning assumptions for air quality conformity analyses. Therefore, ODOT believed that it was in the state's best interest to use the most recent available data to provide a new set of estimated average speeds consistent with those used for urban area travel demand models which were under development at that time. The memo contains comparisons of 2002 speed data obtained from traffic count equipment, automatic traffic recorders (ATRs) which collect data continuously throughout the year. It also contains comparisons of the new speeds with those used to address the one hour standard Gebhart's. The graphs shown in figure 1, taken from the memo, illustrate the comparisons. The first graph compares time mean speeds from the ATRs with space mean speeds from ODOTs travel time study done in 2001and with the speeds used for addressing the one hour standard.

Figure 1 - Speed Comparison Graphs





The following caution statement was taken from the Estimation of Average Speed by Functional Class memo.

CAUTION: *It should be noted that speeds on facilities falling in any one of the federal functional classifications vary greatly between roadways, between hour of the day, and day of the week. So these provide only very rough estimates of speed and should be used with caution. In addition, it is expected that these average statewide speeds are higher than the average speeds in the non-attainment areas because the non-*

attainment counties tend to be more populated and more congested. The document "Highway Vehicle Speed Estimation Procedures For Use in Emission Inventories", September 1991 by Earl Ruiter of Cambridge Systematics Inc. is referenced by EPA's documented procedures for emission inventory preparation. This document suggests post processing travel demand model traffic assignment results to estimate average speeds.

Final space mean speeds that ODOT provided are summarized in the Table 1 below:

Table 4-3 Speed by Federal Functional Class

Functional Class	1990 Analysis Speeds	2001 Speed Study Speeds
FC01	57.3	64.0
FC02	45.3	53.0
FC06	39.9	53.0
FC07	35.1	43.1
FC08	30.5	43.1
FC09	28.0	43.1
FC11	46.3	61.6
FC12	43.3	61.6
FC14	18.9	29.3
FC16	19.6	29.3
FC17	19.6	29.2
FC19	19.6	23.8

It was decided by mutual agreement among individuals within the ODOT Office of Technical Services that these new space mean speed based average speed estimates were reproducible and defensible since they are well documented and should therefore be the speeds used with HPMS** VMT if any year 2002 emissions budget work is done using only the county level VMT summaries discussed in section 5.3.2 Daily Vehicle Miles Traveled (DVMT).

** Note that HPMS VMT is a statewide VMT estimate and the county level DVMT summaries are consistent with the HPMS VMT so the county level DVMT summaries are loosely referred to as HPMS VMTs even though in fact they are not.

4.3.5 Link Group Speed Curves:

The ODOT Modeling & Forecasting Section recommends that Ohio's travel demand forecasting models and ODOT's conformity analysis methods be used to establish the roadway mobile source portion of Ohio's SIP budget for reasons already mentioned in 5.3.2 and to assure consistent methods are used for transportation conformity demonstration analyses and budgets. Therefore, ODOT provided travel demand model runs and the speed curves by link group that ODOT uses for the speed estimates within

the post processing of travel demand model runs for estimating regional emissions. Table 2 shows these link group curves.

Table 4-4 Link Group Codes & Associated BPR Curves

Link Group	Facility Type	Free Flow Speed	Areatype	a	b
1	Freeway	75	Any	0.39	6.3
2	Freeway	70	Any	0.32	7.0
3	Freeway	65	Any	0.25	9.0
4	Freeway	60	Any	0.18	8.5
5	Freeway	55	Any	0.10	10.0
6	Multi-Lane	60	Rural	0.09	6.0
7	Multi-Lane	55	Rural	0.08	6.0
8	Multi-Lane	50	Rural	0.07	6.0
9	Multi-Lane	45	Rural	0.07	6.0
10	2 Lane	Any	Rural	0.34	4.0
10	Urban Street	50	Suburban	0.34	4.0
11	Urban Street	50	Urban	0.74	5.0
12	Urban Street	50	CBD	1.16	6.0
13	Urban Street	40	Suburban	0.38	5.0
14	Urban Street	40	Urban	0.70	5.0
15	Urban Street	40	CBD	1.00	5.0
16	Urban Street	35	Suburban	0.96	5.0
17	Urban Street	35	Urban	1.00	5.0
18	Urban Street	35	CBD	1.40	5.0
19	Urban Street	30	Suburban	1.11	5.0
20	Urban Street	30	Urban	1.20	5.0
21	Urban Street	30	CBD	1.50	5.0

Note: a and b are the BPR curve parameters for the equation

$$T = T_0 \{1 + a * (V/C)^b]$$

More complete details about emissions modeling process employed by ODOT may be found in ODOT documentations. The document titled “Congestion Management & Air Quality Analysis (CMAQ) Program Documentation” dated December 2005 may be obtained from the ODOT web site at www.dot.state.oh.us/urban/data/cmaq.doc (Microsoft Word document)

4.4 Mobile6 Inputs:

The following table contains the inputs supplied to LADCO to process our mobile inventory.

4.4.1 Ohio’s 2005 MOBILE6 Inputs

The following tables are the result of a joint meeting between Ohio EPA, ODOT, and MPOs from around the state. At that meeting Mobile6 inputs were discussed and efforts were made to verify the sources of data inputs for Moble6. Dialogue has continued between the parties.

For historical reference:

>>> Dave Moore <Dave.Moore1@dot.state.oh.us> 4/10/2006 2:13 PM >>>

All,

An air quality coordination meeting has been scheduled for April 27, 2006 at 10:00 AM at ODOT Central Office conference room GA. The primary purpose of this meeting is to discuss development of 2002 mobile source inventories for use in developing the Ohio 2007 8-Hour Ozone SIP Attainment Demonstrations. See meeting agenda below. OEPA is working toward a June 15, 2006 schedule for submitting the 2002 inventories to US EPA.

A key component of the meeting will be to review and confirm the MOBILE6.2 input parameters, by Ohio a/q area, for use in developing the 2002 mobile inventories. See draft template below. The Ohio MPO travel demand models will be used to generate the 2002 VMT inputs to MOBILE. Thanks, DM
DM

IMPORTANT NOTICE: The following tables are not to be used for inventory purposes as the data is subject to change. For the current input table, contact Ohio EPA, Division of Air Pollution Control.

Table 4-5 Mobile Inputs

Cleveland-Akron 2005 Ozone M6.2 Inputs

Includes the following counties:
Ashtabula, Cuyahoga, Geauga, Lake, Lorain, Medina, Portage, Summit

State Programs	
	Input
Stage II Refueling	93/3/86/86
Anti-tampering Programs	96/78/50/22222/21111111/1/12/098./12111112
I/M Programs	Yes
Exclude Ashtabula County - No I/M program	
Program	1 2004 2050 2 T/O OBD I/M
Model Years	1 1996 2050
Vehicles	1 22222 21111111 1
Stringency	1 30.0
Compliance	1 98.0
Waiver Rates	1 1.0 1.0
Cutpoints	
Exemption Age	1 25
Grace Period	1 4
NO TTC Credits	
Effectiveness	
DESC file	
Program	2 2004 2050 2 T/O EVAP OBD & GC
Model Years	2 1996 2050
Vehicles	2 22222 11111111 1
Stringency	
Compliance	2 98.0
Waiver Rates	2 1.0 1.0
Cutpoints	
Exemption Age	2 25
Grace Period	2 4
NO TTC Credits	
Effectiveness	
DESC file	
Program	3 2001 2003 2 T/O ASM 2525 PHASE-IN

Model Years	3 1996 2003
Vehicles	3 22222 21111111 1
Stringency	3 30.0
Compliance	3 98.0
Waiver Rates	3 3.0 1.0
Cutpoints	
Exemption Age	3 25
Grace Period	3 2
NO TTC Credits	
Effectiveness	
DESC file	

Program	4 2001 2050 2 T/O ASM 2525 PHASE-IN
Model Years	4 1975 1995
Vehicles	4 22222 21111111 1
Stringency	4 30.0
Compliance	4 98.0
Waiver Rates	4 3.0 1.0
Cutpoints	
Exemption Age	4 25
Grace Period	4 4
NO TTC Credits	
Effectiveness	
DESC file	

Program	5 1998 2000 2 T/O LOADED/IDLE
Model Years	5 1975 2000
Vehicles	5 22222 21111111 1
Stringency	5 30.0
Compliance	5 98.0
Waiver Rates	5 3.0 1.0
Cutpoints	
Exemption Age	5 25
Grace Period	5 2
NO TTC Credits	
Effectiveness	
DESC file	

Program	6 1996 1997 2 T/O IM240
Model Years	6 1975 1997
Vehicles	6 22222 21111111 1
Stringency	6 30.0
Compliance	6 98.0
Waiver Rates	6 3.0 1.0
Cutpoints	6 CUTPOINT.D
Exemption Age	6 25
Grace Period	6 2
NO TTC Credits	
Effectiveness	
DESC file	

Program	7 1996 2050 2 T/O GC
Model Years	7 1975 1995
Vehicles	7 22222 21111111 1
Stringency	
Compliance	7 98.0
Waiver Rates	7 3.0 1.0
Cutpoints	
Exemption Age	7 25
Grace Period	7 2
NO TTC Credits	
Effectiveness	
DESC file	

Fuel Commands

Fuel Program	1
Oxygenated Fuels	0.00 0.42 0.00 0.036 2
Fuel RVP	9

Alternative Emission Regulations and Control Measures

Rebuild Effects	0.1

External Conditions Commands

Calendar Year	2005
Evaluation Month	7
Min/Max Temperature	National Climatic Data Center

Vehicle Fleet Characteristic Commands

Registration Distribution	Variable

Cincinnati-Dayton-Springfield 2005 Ozone M6.2 Inputs

Includes the following counties:
Ohio: Butler, Clark, Clermont, Clinton, Greene, Hamilton, Miami, Montgomery, Warren
Indiana: Lawrenceburg Twp., Dearborn County
Kentucky: Boone, Campbell and Kenton counties

State Programs

Input

Note: Indiana and Kentucky inputs may not coincide with Ohio inputs

Stage II Refueling 93/3/86/86

Anti-tampering Programs 96/78/05/22222/21111111/1/12/098./12111112

I/M Programs Yes

Excludes Clinton Co. and Miami Co., OH, Dearborn County, IN - No I/M program
Note: I/M inputs for Kentucky counties are not included

Program	1 2004 2050 2 T/O OBD I/M
Model Years	1 1996 2050
Vehicles	1 22222 21111111 1
Stringency	1 30.0
Compliance	1 98.0
Waiver Rates	1 1.0 1.0
Cutpoints	
Exemption Age	1 25
Grace Period	1 2
NO TTC Credits	
Effectiveness	
DESC file	

Program	2 2004 2050 2 T/O EVAP OBD & GC
Model Years	2 1996 2050
Vehicles	2 22222 11111111 1
Stringency	
Compliance	2 98.0
Waiver Rates	2 1.0 1.0
Cutpoints	
Exemption Age	2 25
Grace Period	2 2
NO TTC Credits	
Effectiveness	
DESC file	

Program	3 2001 2003 2 T/O ASM 2525 PHASE-IN
Model Years	3 1996 2003
Vehicles	3 22222 21111111 1
Stringency	3 30.0
Compliance	3 98.0

```
Waiver Rates            3  3.0  1.0
Cutpoints
Exemption Age           3  25
Grace Period            3  2
NO TTC Credits
Effectiveness
DESC file

Program                 4  2001  2050  2  T/O  ASM  2525  PHASE-IN
Model Years             4  1975  1995
Vehicles                4  22222  21111111 1
Stringency              4  30.0
Compliance              4  98.0
Waiver Rates            4  3.0  1.0
Cutpoints
Exemption Age           4  25
Grace Period            4  4
NO TTC Credits
Effectiveness
DESC file

Program                 5  1998  2000  2  T/O  LOADED/IDLE
Model Years             5  1975  2000
Vehicles                5  22222  21111111  1
Stringency              5  30.0
Compliance              5  98.0
Waiver Rates            5  3.0  1.0
Cutpoints
Exemption Age           5  25
Grace Period            5  2
NO TTC Credits
Effectiveness
DESC file

Program                 6  1996  1997  2  T/O  IM240
Model Years             6  1975  1997
Vehicles                6  22222  21111111 1
Stringency              6  30.0
Compliance              6  98.0
Waiver Rates            6  3.0  1.0
Cutpoints               6  CUTPOINT.D
Exemption Age           6  25
Grace Period            6  2
NO TTC Credits
Effectiveness
DESC file

Program                 7  1996  2050  2  T/O  GC
Model Years             7  1975  1995
Vehicles                7  22222  21111111  1
```

Stringency	
Compliance	7 98.0
Waiver Rates	7 3.0 1.0
Cutpoints	
Exemption Age	7 25
Grace Period	7 2
NO TTC Credits	
Effectiveness	
DESC file	

Fuel Commands

Fuel Program	1
Oxygenated Fuels	0.00 0.42 0.00 0.036 2
Fuel RVP	9

Alternative Emission Regulations and Control Measures

Rebuild Effects	0.1

External Conditions Commands

Calendar Year	2005
Evaluation Month	7
Min/Max Temperature	National Climatic Data Center

Vehicle Fleet Characteristic Commands

Registration Distribution	Variable

Other Areas (excluding NOACA/AMATS and OKI/MVRPC) Ozone M6.2 Inputs

Includes the following counties:
Ohio: Belmont, Columbiana, Delaware, Fairfield, Franklin, Jefferson, Knox, Licking, Lucas,Madison, Mahoning, Pickaway, Trumball, Wood

Fuel Commands	
	Input
Fuel Program	1
Oxygenated Fuels	0.00 0.42 0.00 0.036 2
Fuel RVP	9

Alternative Emission Regulations and Control Measures		
Rebuild Effects	0.1	(0.30 for 2018)

External Conditions Commands	
Calendar Year	All
Evaluation Month	7
Min/Max Temperature	National Climatic Data Center

Vehicle Fleet Characteristic Commands	
Registration Distribution	Variable

4.5 Ohio's Mobile Emission Data Processed by LADCO (Lake Michigan Air Director's Consortium):

2005 TDM and Mobile6 input data were provided to LADCO for processing. The data was processed by LADCO with T3 to prepare it as an input into the ConCEPT model. T3 and ConCEPT are described as follows.

4.5.1 T3--Development of Link-Level Mobile Source Emission Inventories:

Highly resolved emission inventories for on-road mobile sources are needed for air quality modeling to develop the necessary technical support for new State Implementation Plans (SIPs) for regional haze, fine particles, and ozone. Emissions for on-road motor vehicles are estimated using vehicle miles traveled, trip starts and ends, speed, and other activity data developed by State Agencies and Metropolitan Planning Organizations (MPOs) using transportation demand models (TDMs), and emission factors from EPA's MOBILE6 model. To support this modeling in the upper Midwest, ENVIRON, working with LADCO, State DOTs, and local MPOs, has developed a software tool (the TDM Transformation Tool, or "T3") that takes TDM output from approximately twenty transportation networks using a variety of models, applies appropriate data transformations, and outputs link- and county-level activity data in a uniform format for input to the CONCEPT emissions processing model (a new emissions processing model also developed with funding from LADCO). In a parallel effort, analyses of extensive automatic traffic recorder (ATR) data collected by State DOTs were conducted to develop temporal profiles (hour of day, day of week, and month of year) of vehicle counts and vehicle mix by roadway type for developing the detailed on-road emission inventories.

T3 provides a conduit from the projections of traffic demand modelers regarding vehicle types, road networks, and vehicle activity to the activity data required by emissions modelers. The primary goals of T3 are to provide an easy mechanism for incorporating TDM model outputs in as "raw" a format as possible, while simultaneously providing a great degree of flexibility in representing the TDM projections in terms acceptable to most air quality models. These goals have been achieved through the use of a dimensional transformation approach, where the dimensions of the various transformations are user-defined - hence the name of the tool.

By Stella Shepard, Alison K. Pollack, John Haasbeek, ENVIRON International Corporation, 101 Rowland Way, Suite 220, Novato, CA. 94945
& Mark Janssen, Lake Michigan Air Directors Consortium (LADCO), 2250 E. Devon Avenue # 250, Des Plaines, IL 60018, janssen@ladco.org

4.5.2 ConCEPT--Consolidated Community Emissions Processing Tool an Open-Source Tool for the Emissions Modeling Community:

The new CONCEPT (CONsolidated Community Emissions Processing Tool) Emissions Processor is now available for use by the emissions modeling community. Developed as joint project between Alpine Geophysics, LLC and ENVIRON Corporation, with Midwest RPO and joint RPO funding, the CONCEPT model combines the best attributes of current emissions modeling systems into an open source model highlighting the following features:

- Open Source. Written primarily in PostgreSQL, the software required for running

CONCEPT is in the public domain. The model itself is GNU Public License (GPL) compliant and users are encouraged to make additions and enhancements to the modeling system.

- Transparent. The database structure of the model makes the system easy to understand, and the modeling codes themselves are extremely well documented to encourage user participation in the customizing the system for specific modeling requirements.

- Quality Control. The CONCEPT model structure and implementation allows for multiple levels of QA analysis during every step of the emissions calculation process. Using the database structures, an emissions modeler can easily trace a process or facility and review the calculation procedures and assumptions for any emissions value.

The CONCEPT model includes modules for the major emissions source categories: area source, point source, on-road motor vehicles, non-road motor vehicles and biogenic emissions, as well as a number of supporting modules, including spatial allocation factor development, speciation profile development, growth and control for point and area sources, and CEM point source emissions handling. The emissions modeling community has already begun development of additional CONCEPT support modules including CEM preprocessing software, graphical QA tools, and an interface to the traffic demand models for on-road motor vehicle emissions estimation.

By Cyndi Loomis, James G. Wilkinson, Alpine Geophysics, LLC, & John Haasbeek, Alison Pollack, ENVIRON Corporation. & Mark Janssen, Lake Michigan Air Directors Consortium (LADCO), 2250 E. Devon Avenue # 250, Des Plaines, IL 60018, janssen@ladco.org

4.5.3 LADCO Ohio Data Outputs for 2005:

The following LADCO outputs and documents can be found at:
www.ladco.org/tech/emis/net05/index.html

Table 4-6 LADCO Data Output

State	Network	T3 Description DOC	M6 Inputs	VMT vs HPMS Excel	Average Day VMT (this should match conformity inventory)	County Emissions Report	All Pollutants After Speciation	Dropped VMT	M6 Run Summary	Pollutant Totals (Short)	Raw Summary (pol,veh, etype)	Hourly Temporal Summary	Hourly Veh Mix Summary	Hourly Speed Summary (with volume/ capacity)
OH	AKRON	AKRON	OH	OH	AKRON	1	1	1	1	1	1	1	1	1

OH	CANTON	CANTON	OH	OH	CANTON	1	1	1	1	1	1	1	1	1
OH	CINCI	CINCI	OH	OH	CINCI	1	1	1	1	1	1	1	1	1
OH	CLEVE	CLEVE	OH	OH	CLEVE	1	1	1	1	1	1	1	1	1
OH	COLUMBUS	COLUMBUS	OH	OH	COLUMBUS	1	1	1	1	1	1	1	1	1
OH	SPRINGFLD	SPRINGFLD	OH	OH	SPRINGFLD	1	1	1	1	1	1	1	1	1
OH	TOLEDO	TOLEDO	OH	OH	TOLEDO	1	1	1	1	1	1	1	1	1
OH	YNGSTOWN	YNGSTOWN	OH	OH	YNGSTOWN	1	1	1	1	1	1	1	1	1
OH	STATEWD	STATEWD	OH	OH	STATEWD	1	1	1	1	1	1	1	1	1

Additional Documents on LADCO Web Page:

“Comparison to EPA's Default Model NMIM”

“How we Build the 2005 Vmt/Networks”

“Spreadsheet/Graphics on Vehicle Mix”

“Background on the T3 Tool “

4.6 MPO Contact Table

Table 4-7 County Summary Table of MPOs by County

FIPS	County	Model Network	MPO	Contact Person
39001	Adams	Statewide		
39003	Allen	Statewide	Lima Allen County Regional Planning Commission	Tom Mazur
39005	Ashland	Statewide		
39007	Ashtabula	Statewide		
39009	Athens	Statewide		
39011	Auglaize	Statewide		
39013	Belmont	Statewide	Bel-O-Mar Regional Council and Interstate Planning Commission	Rakesh Sharma
39015	Brown	Statewide		
39017	Butler	Cincinnat/Dayton	Ohio-Kentucky-Indiana Regional Council of Governments	Andy Reser
39019	Carroll	Statewide		
39021	Champaign	Statewide		
39023	Clark	Springfield	Coordinating Committee of the Clark County-Springfield	Eric Ottoson

			Transportation Study	
39025	Clermont	Cincinnat/Dayton	Ohio-Kentucky-Indiana Regional Council of Governments	Andy Reser
39027	Clinton	Statewide		
39029	Columbiana	Statewide		
39031	Coshocton	Statewide		
39033	Crawford	Statewide		
39035	Cuyahoga	Cleveland	Northeast Ohio Areawide Coordinating Agency	Bill Davis
39037	Darke	Statewide		
39039	Defiance	Statewide		
39041	Delaware	Columbus	Mid-Ohio Regional Planning Commission	Nick Gill
39043	Erie	Statewide		
39045	Fairfield	Statewide		
39047	Fayette	Statewide		
39049	Franklin	Columbus	Mid-Ohio Regional Planning Commission	Nick Gill
39051	Fulton	Statewide		
39053	Gallia	Statewide		
39055	Geauga	Cleveland	Northeast Ohio Areawide Coordinating Agency	Bill Davis
39057	Greene	Cincinnat/Dayton	Miami Valley Regional Planning Commission	Ana Ramirez
39059	Guernsey	Statewide		
39061	Hamilton	Cincinnat/Dayton	Ohio-Kentucky-Indiana Regional Council of Governments	Andy Reser
39063	Hancock	Statewide		
39065	Hardin	Statewide		
39067	Harrison	Statewide		
39069	Henry	Statewide		
39071	Highland	Statewide		
39073	Hocking	Statewide		
39075	Holmes	Statewide		
39077	Huron	Statewide		
39079	Jackson	Statewide		
39081	Jefferson	Statewide	Brooke-Hancock-Jefferson Transportation Study Policy Committee	Mike Proprocki
39083	Knox	Statewide		
39085	Lake	Cleveland	Northeast Ohio Areawide Coordinating Agency	Bill Davis
39087	Lawrence	Statewide	KYOVA Interstate Planning Commission	
39089	Licking	Columbus	Licking County Area Transportation Study	Matthew Hill
39091	Logan	Statewide		
39093	Lorain	Cleveland	Northeast Ohio Areawide	Bill Davis

			Coordinating Agency	
39095	Lucas	Toledo	Toledo Metropolitan Area Council of Governments	Sujatha Mohanakrishnan
39097	Madison	Statewide		
39099	Mahoning	Youngstown	Eastgate Regional Council of Governments	R.P. Samulka
39101	Marion	Statewide		
39103	Medina	Cleveland	Northeast Ohio Areawide Coordinating Agency	Bill Davis
39105	Meigs	Statewide		
39107	Mercer	Statewide		
39109	Miami	Cincinnat/Dayton	Miami Valley Regional Planning Commission	Ana Ramirez
39111	Monroe	Statewide		
39113	Montgomery	Cincinnat/Dayton	Miami Valley Regional Planning Commission	Ana Ramirez
39115	Morgan	Statewide		
39117	Morrow	Statewide		
39119	Muskingum	Statewide		
39121	Noble	Statewide		
39123	Ottawa	Statewide		
39125	Paulding	Statewide		
39127	Perry	Statewide		
39129	Pickaway	Statewide		
39131	Pike	Statewide		
39133	Portage	Akron	Akron Metropolitan Area Transportation Study	Jason Segedy
39135	Preble	Statewide		
39137	Putnam	Statewide		
39139	Richland	Statewide	Richland County Regional Planning Commission	John Adams
39141	Ross	Statewide		
39143	Sandusky	Statewide		
39145	Scioto	Statewide		
39147	Seneca	Statewide		
39149	Shelby	Statewide		
39151	Stark	Canton	Stark County Regional Planning Commission	Dan Slicker
39153	Summit	Akron	Akron Metropolitan Area Transportation Study	Jason Segedy
39155	Trumbull	Youngstown (partial county model coverage)	Eastgate Regional Council of Governments	R.P. Samulka
39157	Tuscarawas	Statewide		
39159	Union	Statewide		
39161	Van Wert	Statewide		
39163	Vinton	Statewide		
39165	Warren	Cincinnat/Dayton	Ohio-Kentucky-Indiana Regional Council of Governments	Andy Reser, OKI +

			+ Miami Valley Regional Planning Commission	Ana Ramirez, MVRPC
39167	Washington	Statewide	Wood-Washington-Wirt Interstate Planning Commission	
39169	Wayne	Statewide		
39171	Williams	Statewide		
39173	Wood	Toledo	Toledo Metropolitan Area Council of Governments	Sujatha Mohanakrishnan
39175	Wyandot	Statewide		

NOTE: Complete MPO information can be found at, www.dot.state.oh.us/urban/mpomap.htm and at www.dot.state.oh.us/urban/mpolist.htm#Cleveland .

SECTION 5

MARINE, AIRCRAFT and RAIL (MAR) SOURCES

MAR sources are non-road sources which are significant enough in terms of emissions to be considered separately from the rest of the non-road sources. The MAR inventory consists of commercial marines, aircraft and locomotive sources. The marine and locomotive inventory is generated by Environ[1] under contract with LADCO and the aircraft inventory is generated by Ohio EPA.

5.1 Marine Vessel Sources

The approach to commercial marine emission estimates needed to be flexible because the activity data was available in many formats. Emission estimates were determined either by multiplying engine power, load factor, hours per year of operation, or on the basis of the number of gallons of fuel consumed.

Emissions were determined for ten subclasses of vessel types: Deep draft vessels (DDV) at port, DDV mid-late, push boats (rivers/lakes), tugs, ferries, other special (excursion) vessels, support vessels, dredges, commercial fishing, and military vessels (Coast Guard). These were linked to various Ohio lakes and rivers.

Because of the large variety of methodologies employed, inventory tables for the ten subcategories are detailed in the complete inventory prepared and published by ENVIRON International Corporation: **LADCO 2005 COMMERCIAL MARINE EMISSIONS**, by Christian E. Lindhjem, March, 2007.

Emission totals produced by ENVIRON were provided to LADCO to submit to EPA for Ohio's State Implementation Plan (SIP).

5.2 Rail Sources

The primary activity unit used to determine emissions is gallons of fuel consumed. Emission rates were derived from EPA documents provided as support documentation for the 1997 locomotive emission standards (EPA, 1997). Gallons of fuel consumed were based on rail activity.

Rail activity was broken down into four Source Category Codes (SCC). Class I, line-haul rail: Large interstate railroad companies like Union Pacific and Norfolk Southern. Class I,II, III, switching rail: Yard operations. Class II, III line haul: Regional and local railroads. And Passenger rail: AMTRAK.

Class I, line-haul represents 84.3% of fuel used and the largest emission's category. The complete emission's inventory was prepared and published by ENVIRON International Corporation: **LADCO 2005 LOCOMOTIVE EMISSIONS**, by Christian E. Lindhjem, February, 2007.

Emission totals produced by ENVIRON were provided to LADCO to submit to EPA for Ohio's State Implementation Plan (SIP).

EPA. 1997: "Locomotive Emission Standards." Regulatory Support Document, United States Environmental Protection Agency, Office of Mobile Sources, April. And EPA 1997, Emission Factors for Locomotives," Environmental Protection Agency, EPA420-F-97-051, December.

5.3 Aircraft Sources

INTRODUCTION:

The aircraft emission's inventory is derived by taking the number of Landings and Take Offs (LTOs) per year and multiplying by an emission factor. In the Ohio inventory when specific aircraft models and engine type emission factors are known they were used. For the rest of the inventory the emission factors came from USEPA's fleet average emissions data. Those results are then compiled as tons per year per pollutant by county. The following describes the components, methodology, and concludes with a description of an Access based aircraft emission calculator.

COMPONENTS:

I. Ohio Airports:

A list of both towered and non-towered airports in Ohio is obtained from the Ohio Department of Transportation. See: www.dot.state.oh.us/aviation/ In conversation with ODOT two individuals stated that the 164 airports listed covered over 90% of the airports in Ohio. See Table 1.

II. Number of Operations/LTOs by Airport/County:

The ODOT list contained the number of operations a year per airport. An operation is either a landing or a take-off. A Landing and Take Off (LTO) is required for FAA EDMS calculations. LTOs were derived simply by dividing the number of operations by two. These were totaled by county.

Table 5-1 Number of operations and LTOs for 2005

County	Airport Name	ID	Total Operations	LTOs/Year
Adams	Alexander Salamon	AMT	**5210**	2605
Allen	Allen County	AOH	**32500**	16250
Ashland	Ashland County	3G4	**49240**	24620
Ashtabula	Ashtabula County	HZY	**16886**	8443
Ashtabula	Germack	7D9	**840**	420
Athens	Ohio University	UNI	**51600**	25800
Auglaize	Neil Armstrong	AXV	**29456**	14728
Belmont	Barnesville-Bradfield	6G5	**10150**	5075
Belmont	Alderman	2P7	**6150**	3075
Brown	Brown County	GEO	**5157**	2578.5
Butler	Butler County Regional	HAO	**61687**	30843.5
Butler	Hook Field Municipal	MWO	**40050**	20025
Butler	Miami University	OXD	**16708**	8354
Carroll	Carroll County -Tolson	TSO	**34950**	17475
Carroll	Parsons	5D6	**2674**	1337
Champaign	Grimes Field	I74	**23480**	11740
Champaign	Weller	38I	**300**	150
Clark	Springfield-Beckley Municipal	SGH	**64033**	32016.5
Clark	Mad River	I54	**15350**	7675
Clermont	Clermont County	I69	**35741**	17870.5
Clinton	Airborne Airpark	ILN	**52000**	26000
Clinton	Clinton Field	I66	**29360**	14680
Clinton	Hollister Field	2B6	**161**	80.5
Columbiana	Columbiana County	Ø2G	**31146**	15573
Columbiana	Koons	8G8	**2546**	1273
Coshocton	Richard Downing	I4Ø	**19550**	9775
Coshocton	Tri-City	8ØG	**8085**	4042.5
Crawford	Port Bucyrus	17G	**24871**	12435.5
Crawford	Galion Municipal	GQQ	**5216**	2608
Cuyahoga	Burke Lakefront	BKL	**97100**	48550
Cuyahoga	Cleveland-Hopkins International	CLE	**234356**	117178
Cuyahoga	Cuyahoga County	CGF	**79774**	39887
Darke	Darke County	VES	**9238**	4619
Defiance	Defiance Memorial	DFI	**9130**	4565
Delaware	Delaware Municipal	DLZ	**39300**	19650
Delaware	Packer	5E9	**3181**	1590.5
Erie	Hinde	88D	**1350**	675
Erie	Kelleys Island	89D	**25495**	12747.5
Erie	Griffing-Sandusky	SKY	**112100**	56050

Erie	Wakeman	I64	**17324**	8662
Fairfield	Miller's Farm	7B4	**360**	180
Fairfield	Fairfield County	LHQ	**43066**	21533
Fayette	Fayette County	I23	**29405**	14702.5
Franklin	Ohio State University	OSU	**134459**	67229.5
Franklin	Port Columbus International	CMH	**218438**	109219
Franklin	Rickenbacker International	LCK	**96200**	48100
Franklin	Bolton Field	TZR	**69149**	34574.5
Franklin	Columbus Southwest	Ø4I	**11833**	5916.5
Franklin	Darby Dan	6I6	**11260**	5630
Fulton	Fulton County	USE	**21123**	10561.5
Gallia	Gallia-Meigs Regional	GAS	**12200**	6100
Geauga	Gates	7D8	**4200**	2100
Geauga	Geauga County	7G8	**5350**	2675
Greene	Greene County - Lewis A. Jackson	I19	**37400**	18700
Greene	Bloom	14I	**100**	50
Guernsey	Cambridge Municipal	CDI	**6040**	3020
Hamilton	Lunken	LUK	**129430**	64715
Hamilton	Blue Ash	ISZ	**35000**	17500
Hamilton	Cincinnati West	I67	**30197**	15098.5
Hancock	Bluffton	5G7	**71980**	35990
Hancock	Findlay	FDY	**19800**	9900
Hancock	Priebe	7D5	**3850**	1925
Hardin	Ada	ØD7	**331**	165.5
Hardin	Hardin County	I95	**6562**	3281
Hardin	Elliott's Landing	O74	**1560**	780
Harrison	Harrison County	8G6	**11900**	5950
Henry	Henry County	7W5	**15637**	7818.5
Highland	Highland County	HOC	**18325**	9162.5
Holmes	Holmes County	1ØG	**21400**	10700
Huron	Huron County	5A1	**10100**	5050
Huron	Willard	8G1	**2715**	1357.5
Jackson	James A. Rhodes	I43	**6053**	3026.5
Jefferson	Jefferson County Airpark	2G2	**15969**	7984.5
Jefferson	Eddie Dew Memorial	1G8	**3540**	1770
Knox	Knox County	4I3	**20150**	10075
Knox	Wynkoop	6G4	**4691**	2345.5
Lake	Concord Airpark	2G1	**4510**	2255
Lake	Willoughby Lost Nation Municipal	LNN	**45085**	22542.5
Lawrence	Lawrence County Airpark	HTW	**41910**	20955
Licking	Newark-Heath	VTA	**12457**	6228.5
Logan	Bellefontaine Regional	EDJ	**8325**	4162.5
Lorain	Columbia	4G8	**5150**	2575
Lorain	Elyria	1G1	**14300**	7150
Lorain	Lagrange	92D	**1155**	577.5
Lorain	Lorain County Regional	LPR	**62000**	31000
Lorain	Reader-Botsford Airfield	67D	**18700**	9350
Lucas	Toledo Express	TOL	**94600**	47300

Madison	Madison County	UYF	**41410**	20705
Mahoning	Salem Airpark	38D	**16920**	8460
Mahoning	Tri-City	3G6	**10555**	5277.5
Mahoning	Elser Metro	4G4	**49232**	24616
Mahoning	Lansdowne	Ø4G	**750**	375
Marion	Marion Municipal	MNN	**42650**	21325
Medina	Medina Municipal	1G5	**79685**	39842.5
Medina	Wadsworth Municipal	3G3	**41025**	20512.5
Medina	Weltzien Skypark	15G	**79130**	39565
Mercer	Lakefield	CQA	**16212**	8106
Miami	Hartzell Field	I17	**10200**	5100
Miami	Troy Skypark	37I	**4264**	2132
Miami	Waco Field	1WF	**0**	0
Monroe	Monroe County	4G5	**3324**	1662
Montgomery	Brookville Air-Park	I62	**29359**	14679.5
Montgomery	James M. Cox Dayton Intl	DAY	**134524**	67262
Montgomery	Dayton Wright Brothers	MGY	**89045**	44522.5
Montgomery	Moraine Airpark	I73	**12938**	6469
Montgomery	Dahio Trotwood	I44	**1853**	926.5
Montgomery	Phillipsburg	3I7	**68000**	34000
Morgan	Morgan County	I71	**5725**	2862.5
Morrow	Morrow County	4I9	**19108**	9554
Muskingum	Zanesville Municipal	ZZV	**33312**	16656
Muskingum	Parr	42I	**16150**	8075
Noble	Noble County - Mike Brienza Field	I1Ø	**5950**	2975
Ottawa	Middle Bass-East Point	3W9	**1300**	650
Ottawa	Middle Bass Island	3T7	**6500**	3250
Ottawa	North Bass Island	3X5	**1000**	500
Ottawa	Carl R. Keller Field	PCW	**20890**	10445
Ottawa	Put-In-Bay	3W2	**15140**	7570
Paulding	Paulding	2H8	**2100**	1050
Perry	Crooksville	I84	**400**	200
Perry	Perry County	I86	**4550**	2275
Pickaway	Pickaway County	CYO	**35450**	17725
Pickaway	Clarks Dream Strip	Ø3I	**2770**	1385
Pike	Pike County	EOP	**2012**	1006
Portage	Freedom Air Field	7D6	**1623**	811.5
Portage	Farview	86D	**3353**	1676.5
Portage	Mills	7E3	**1050**	525
Portage	Portage County	29G	**9621**	4810.5
Putnam	Ruhe's	R47	**13250**	6625
Putnam	Putnam County	OWX	**11910**	5955
Putnam	Ohio Dusting Co.	6C2	**2995**	1497.5
Richland	Mansfield Lahm Regional	MFD	**57518**	28759
Richland	Shelby Community	12G	**2012**	1006
Ross	Ross County	RZT	**50150**	25075
Sandusky	Fremont	14G	**37450**	18725
Sandusky	Sandusky County Regional	S24	**6148**	3074

Scioto	Greater Portsmouth Regional	PMH	**45830**	22915
Seneca	Bandit Field	5D9	**140**	70
Seneca	Fostoria Metropolitan	FZI	**7900**	3950
Seneca	Weiker	82D	**320**	160
Seneca	Seneca County	16G	**60165**	30082.5
Shelby	Sidney Municipal	I12	**20500**	10250
Stark	Barber	2D1	**13750**	6875
Stark	Miller Airport	4G3	**8000**	4000
Stark	Beach City	2D7	**6112**	3056
Summit	Akron Fulton International	AKR	**26000**	13000
Summit	Akron-Canton Regional	CAK	**120441**	60220.5
Summit	Mayfield	1D4	**450**	225
Summit	Kent State University	1G3	**72500**	36250
Trumbull	Braceville	41N	**425**	212.5
Trumbull	Warren	62D	**14738**	7369
Trumbull	Youngstown-Warren Regional	YNG	**98298**	49149
Tuscarawas	Harry Clever Field	PHD	**54880**	27440
Union	Union County	MRT	**31886**	15943
Van Wert	Van Wert County	VNW	**20516**	10258
Vinton	Vinton County	22I	**5225**	2612.5
Warren	Warren County	I68	**24951**	12475.5
Warren	Red Stewart Airfield	4ØI	**16800**	8400
Wayne	Wayne County	BJJ	**96520**	48260
Williams	Williams County	ØG6	**10010**	5005
Wood	Wood County	1GØ	**27405**	13702.5
Wood	Bordner	3D8	**2200**	1100
Wood	Deshler Municipal	6D7	**2000**	1000
Wood	Metcalf	TDZ	**90700**	45350
Wyandot	Wyandot County	56D	**7410**	3705

III. Aircraft Models and Number of LTO/yr:

Specific aircraft models by airport (generally the larger airports) is obtained from “Table 7” provided by the United States Department of Transportation, Office of Airline Information. This provided the number of LTO’s for each aircraft model per year per airport.

Table 2. Sample from “Table 7.” This is the all community total of aircraft models for the Akron/Canton area. “All Service” departures were used as the number of LTOs per year for that model. Listed in the original table are aircraft model by airport and number of services/LTOs.

TOTAL DEPARTURES PERFORMD

Aircraft Model	Scheduled Service	Non-Sched Service	All Service
A-318	1		1
A319	384		384
BOEING 717-200	3850		3850
BOEING 727-100		1	1
BOEING 727-200		5	5
BOEING 737-100/200		74	74
BOEING 737-200C	3	3	6
BOEING 737-300		2	2
BOEING 737-700/LR	212		212
BOEING 737-800		5	5
BOEING 757-200		4	4
BOEING 767-300/ER		4	4
CANADAIR RJ-100/ER	542	3	545
CANADAIR RJ-700	2881		2881
CONVAIR CV-580		3	3
DASSAULT FALCON		7	7
DHC8-100 DASH 8	2		2
DOUGLAS DC-9-15F		13	13
DOUGLAS DC-9-30		6	6
EMBRAER-145	144		144
RJ-200ER/RJ-440	5519		5519
SAAB-FAIRCHD 340/B	1804		1804
ALL TYPES	15342	130	15472

IV. Emission Factors:

Where there was specific aircraft model data the emission factors were derived using the FAA's Emission Dispersion Modeling System (EDMS). EDMS is a combined emissions and dispersion model for assessing air quality at civilian airports and military air bases. The model was developed by the Federal Aviation Administration (FAA) in cooperation with the United States Air Force (USAF). The model is used to produce an inventory of emissions generated by sources on and around the airport or air base, and to calculate pollutant concentrations in these environments.

Table 5-2 EDMS Aircraft Emissions

Emissions provided by Michigan Department of Environmental Quality. (The few aircraft in Ohio not included in the table had emissions derived by EDMS 5.0 in-house.)

EDMS Aircraft Emissions/LTO by Aircraft Type
EDMS 4.5 Emissions Inventory Report of 2005 Aircraft Inventory Emissions Factors

Year 2005	Lbs Emitted Per LTO						
Aircraft Type	CO	NOx	HC	VOC	SO2	PM2.5	PM10
A- 318	19.8	18.7	4.0	4.4	1.5	0.0	0.0
A-300-600/R/CF/RCF	27.1	56.4	2.0	2.2	4.0	0.2	0.2
A-300B/C/F-100/200	30.2	52.5	3.5	3.7	3.3	0.2	0.2
A-310-200C/F	32.6	52.5	7.3	7.9	3.3	0.2	0.2
A-319	19.8	18.7	4.0	4.4	1.5	0.0	0.0
A320-100/200	13.7	19.8	1.3	1.3	1.8	0.2	0.2
A-321	16.8	36.8	3.1	3.3	2.2	0.0	0.0
A-330-200	29.8	61.5	0.4	0.4	4.4	0.2	0.2
AVROLINER RJ85	24.7	9.5	2.9	3.3	1.3	0.2	0.2
BAE-146-300	24.7	9.0	3.1	3.3	1.3	0.2	0.2
BEECH 1900 A/B/C	11.0	1.1	3.3	3.5	0.2	0.0	0.0
BEECH KINGAIR C-90	1.8	0.9	0.2	0.2	0.2	0.0	0.0
717-200	11.7	23.4	0.0	0.0	1.5	0.0	0.0
727-100	21.4	23.1	4.6	5.1	2.9	0.4	0.4
727-100C/QC	44.5	19.8	4.6	5.1	2.4	1.1	1.1
727-200	19.6	27.3	2.9	3.1	3.3	1.1	1.1
737-100/200	14.1	16.1	2.2	2.4	2.0	0.7	0.7
737-200C	13.9	17.4	6.8	7.5	2.0	0.9	0.9
737-300	28.7	15.9	1.8	2.0	1.8	0.0	0.0
737-400	26.5	18.5	1.5	1.5	1.8	0.0	0.0
737-500	24.7	21.2	1.3	1.3	2.0	0.0	0.0
737-700/LR	17.6	20.1	2.0	2.0	1.8	0.4	0.4
737-800	15.7	27.1	1.5	1.8	2.0	0.7	0.7
737-900	15.7	27.1	1.5	1.8	2.0	0.7	0.7
747-100	252.6	108.5	106.7	116.8	7.1	0.4	0.4
747-200/300	60.6	104.7	7.1	7.7	6.8	0.7	0.7
747-400	67.0	105.6	5.7	6.4	7.3	0.7	0.7
757-200	24.7	35.7	2.0	2.2	2.6	0.4	0.4
757-300	27.1	33.1	0.4	0.4	3.1	0.2	0.2
767-200/ER	32.6	52.5	7.3	7.9	3.3	0.2	0.2
767-300/ER	32.0	62.2	2.6	2.9	4.0	0.4	0.4
777	32.8	85.1	5.1	5.7	4.4	0.4	0.4
CANADAIR RJ-100/ER	16.3	4.9	1.5	1.8	0.7	0.0	0.0
CANADAIR RJ-700	12.6	9.3	0.0	0.0	1.1	0.0	0.0
CESSNA 208	1.1	0.4	0.0	0.0	0.0	0.0	0.0
CONVAIR CV-580	36.2	0.9	8.8	9.5	0.7	0.0	0.0
DASSAULT FALCON	13.7	2.6	2.4	2.6	0.2	0.0	0.0
DHC8-100 DASH 8	5.1	3.1	0.0	0.0	0.4	0.0	0.0
DORNIER 328 JET	1.3	6.6	11.9	12.6	0.7	0.0	0.0
DOUGLAS DC-10-10	102.5	76.7	38.6	42.1	4.2	0.0	0.0
DOUGLAS DC-10-30	45.4	78.7	5.3	5.7	5.1	0.4	0.4

DOUGLAS DC-10-40	131.8	81.8	30.2	33.1	6.0	0.7	0.7
DOUGLAS DC-8-63	263.5	25.6	219.1	239.9	4.2	5.1	5.1
DOUGLAS DC-8-71	53.6	34.6	3.1	3.3	3.7	0.0	0.0
DOUGLAS DC-8-73	53.6	34.6	3.1	3.3	3.7	0.0	0.0
DOUGLAS DC-9-10	14.1	14.6	3.7	4.0	1.8	0.2	0.2
DOUGLAS DC-9-15F	14.1	14.6	3.7	4.0	1.8	0.2	0.2
DOUGLAS DC-9-30	14.1	14.6	3.7	4.0	1.8	0.2	0.2
DOUGLAS DC-9-40	39.7	16.5	10.8	11.9	2.0	1.3	1.3
DOUGLAS DC-9-50	12.6	20.1	1.8	1.8	2.2	0.9	0.9
EMBRAER-135	12.8	5.5	1.1	1.3	0.7	0.0	0.0
EMBRAER-140	13.7	6.0	1.3	1.3	0.7	0.0	0.0
EMBRAER-145	6.4	6.8	1.1	1.1	0.7	0.0	0.0
EMBRAER-170	9.0	9.7	0.0	0.0	1.1	0.0	0.0
F28-4000/6000	76.7	10.4	77.2	84.4	1.5	0.0	0.0
JETSTREAM 41	4.6	2.0	0.4	0.7	0.2	0.0	0.0
L-101101/100/200	33.3	112.0	6.2	6.8	5.7	1.3	1.3
LEAR-25	75.2	0.7	7.9	8.4	0.2	0.0	0.0
LOCKHEED L100-30	48.7	9.9	19.6	21.4	1.8	0.0	0.0
MD-11	47.8	93.3	4.0	4.4	6.0	0.7	0.7
MD-80, 1, 2, 3, 7, 8	16.3	20.3	0.0	0.0	2.2	0.2	0.2
MD-90	12.1	23.8	0.2	0.2	2.0	0.2	0.2
RJ-200ER/RJ-440	16.3	4.9	1.5	1.8	0.7	0.0	0.0
SAAB-FAIRCHD 340/B	4.2	1.5	1.5	1.5	0.2	0.0	0.0

NOTE: Where specific aircraft model data was not available fleet emissions were used. EPA default fleet average emission factors were taken from "Documentation for Aircraft, Commercial Marine Vessel, ,Locomotive, and Other Non-road Components of the National Emissions Inventory. 2005, see Appendix A, Aircraft Emission Estimation Methodology." Specific model LTOs were subtracted from county LTO totals to eliminate double counting those LTOs.

Table 5-3 Fleet Emission Factor Categories

Fleet emission factors were broken down into three categories. Itinerant General, Local General, and Military.

Table 5-3a Fleet Average Emission Factors for Itinerant General Aircraft.

(Taken from : Table A-5)

Pollutant	Emission Factors (lbs/LTO)
HC	1.234
NOx	0.158
CO	28.13
SOx	0.015
PM10	0.60333

Note: *Air taxi HC emissions * VOC/HC (*0.9914) *conversion factor = air taxi VOC estimate*

Table 5-3b Fleet Average Emission Factors for Local General Aircraft.

(Taken From: Table A-11)

Pollutant	**Emission Factors (lbs/LTO)**
HC	0.394
NOx	0.065
CO	12.014
SOx	0.01
PM10	0.2367

Note: *GA HC emissions * VOC/HC(*0.9708) *conversion factor = GA VOC estimate*

Table 5-3c Fleet Average Emission Factors for Military Aircraft.

(Taken from: Table A-17)

Pollutant	**Emission Factors (lbs/LTO**
HC	1.234
NOx	0.158
CO	28.13
SOx	0.015
PM10	0.60333

Note: *Military HC emissions * VOC/HC(*1.1046) *conversion factor = Military VOC estimate*

METHODOLOGY

Introduction

The following information was considered in the development of emission estimates:

1. Commercial scheduled and non-scheduled aircraft air carrier activity and commercial air freight activity by aircraft model types,

2. General aviation and air taxi annual local and itinerant operations for year 2005,

3. Military annual local and itinerant operations for year 2005.

Due to the need to have aircraft operations information expressed as landing/take off (LTO) cycles, the following assumptions were made:

1. For commercial aircraft and commercial air freight activity, the number of annual aircraft annual LTO cycles was assumed to be equal to the number of

departures. The daily LTO cycle frequency was then obtained by dividing the yearly LTO cycles by 365.

2. For general aircraft annual local and itinerant airport operations, each respective operations total was divided by 2 to obtain the corresponding year local and itinerant LTO cycles. The expected daily local and itinerant LTO cycles then were obtained by dividing these annual totals by 365.

3. For military annual local and itinerant operations, each respective operations total was divided by 2 to obtain the corresponding year local and itinerant LTO cycles. The expected military daily local and itinerant LTO cycles then were obtained by dividing these annual totals by 365.

Airport LTO cycles were further categorized into commercial aircraft by plane and engine type, general aviation itinerant aircraft of unknown aircraft type, general aviation local aircraft of unknown aircraft type, and military aircraft. This was necessary in order to utilize the U.S. Department of Transportation, Federal Aviation Administration EDMS Emissions and Dispersion Modeling System. Commercial and air freight aircraft emission factors per LTO cycle were determined using EDMS for each commercial aircraft type models where possible were used at each towered airport. Default commercial aircraft engine type, and Environmental Protection Agency (EPA) default time in mode values for takeoff, approach, and landing roll times were used in the EDMS model simulations.

For those aircraft types that could not be determined using the EDMS emissions model, aircraft emission factors based upon EPA alternative fleet average procedures were then used to estimate their emissions. These included general aviation and air taxi itinerant aircraft of unknown aircraft type, general aviation local aircraft of unknown aircraft type, and military aircraft. Conversion from total hydrocarbons to volatile organic compounds was performed and based upon the EPA guidance.

APPROACH

1. A list of more than 90% of the airports was obtained from the Ohio Department of Transportation. These were classed by airport, county, aircraft flight classification, and the total number of operations per year.

2. The number of operations (a landing or a take off) were then divided by two giving the number of LTOs per year per airport. These airports were combined by county for the total number of LTOs per year, per county.

3. In dialog with ODOT it was determined that the following Ohio flight groups of aircraft be combined to match the three categories used by the USEPA in calculating emissions.

Itinerant (General, air carrier, commuter, air taxi, general aviation itinerant)

Local (General aviation local)

Military (Military)

4. LTOs for specific models of aircraft per airport were taken from the FAA Table 7. See **Table 2** above. These were then combined to give the number of LTOs per aircraft model per county. Specific model LTOs were subtracted from county totals to avoid double counting those LTOs.

5. Emission factors were determined from the FAA's EDMS program for specific aircraft model and engine type. See **IV. Emission factors** above. The aircraft emission table provided by Michigan has the emission factors for most of the aircraft flown in Ohio. . Where specific aircraft model data was not available USEPA average fleet emissions were used.

6. Emission factors times LTOs by county yielded tons per year per county.

Table 5-4 Pollutant by County (Sample)

County	POLLUTANT	ACTIVITY(LTOS/YEAR)	ACTIVITY(LTOS/DAY)	EMISSIONS(TON/YEAR)
ADAMS	CO	2605	7.136986	24.552325
ADAMS	HC	2605	7.136986	0.977285
ADAMS	NOX	2605	7.136986	0.136045
ADAMS	PM10-PRI	2605	7.136986	0.513114825
ADAMS	PM25-PRI	2605	7.136986	0
ADAMS	SOX	2605	7.136986	0.0157875
ADAMS	VOC	2605	7.136986	0.96314234
ALLEN	CO	16250	44.52055	147.945065
ALLEN	HC	16250	44.52055	5.841097
ALLEN	NOX	16250	44.52055	0.827189
ALLEN	PM10-PRI	16250	44.52055	3.081191265
ALLEN	PM25-PRI	16250	44.52055	0
ALLEN	SOX	16250	44.52055	0.0984575
ALLEN	VOC	16250	44.52055	5.769568254
ASHLAND	CO	24620	67.45205	173.67794
ASHLAND	HC	24620	67.45205	6.19414
ASHLAND	NOX	24620	67.45205	0.94895
ASHLAND	PM10-PRI	24620	67.45205	3.532515
ASHLAND	PM25-PRI	24620	67.45205	0
ASHLAND	SOX	24620	67.45205	0.1311
ASHLAND	VOC	24620	67.45205	6.07175247
ASHTABULA	CO	8863	24.28219	78.115087
ASHTABULA	HC	8863	24.28219	3.042551
ASHTABULA	NOX	8863	24.28219	0.431593

ASHTABULA	PM10-PRI	8863	24.28219	1.623493455
ASHTABULA	PM25-PRI	8863	24.28219	0
ASHTABULA	SOX	8863	24.28219	0.0520325
ASHTABULA	VOC	8863	24.28219	2.99420213
ATHENS	CO	25800	70.68493	196.874985
ATHENS	HC	25800	70.68493	7.267183
ATHENS	NOX	25800	70.68493	1.081521
ATHENS	PM10-PRI	25800	70.68493	4.037266335
ATHENS	PM25-PRI	25800	70.68493	0
ATHENS	SOX	25800	70.68493	0.1420925
ATHENS	VOC	25800	70.68493	7.128180006

7. Emissions were then summed by pollutants in each county by SCC aircraft category type so data could be provided to LADCO in the EPA prescribed NEI – NIF format.

DATA ERROR

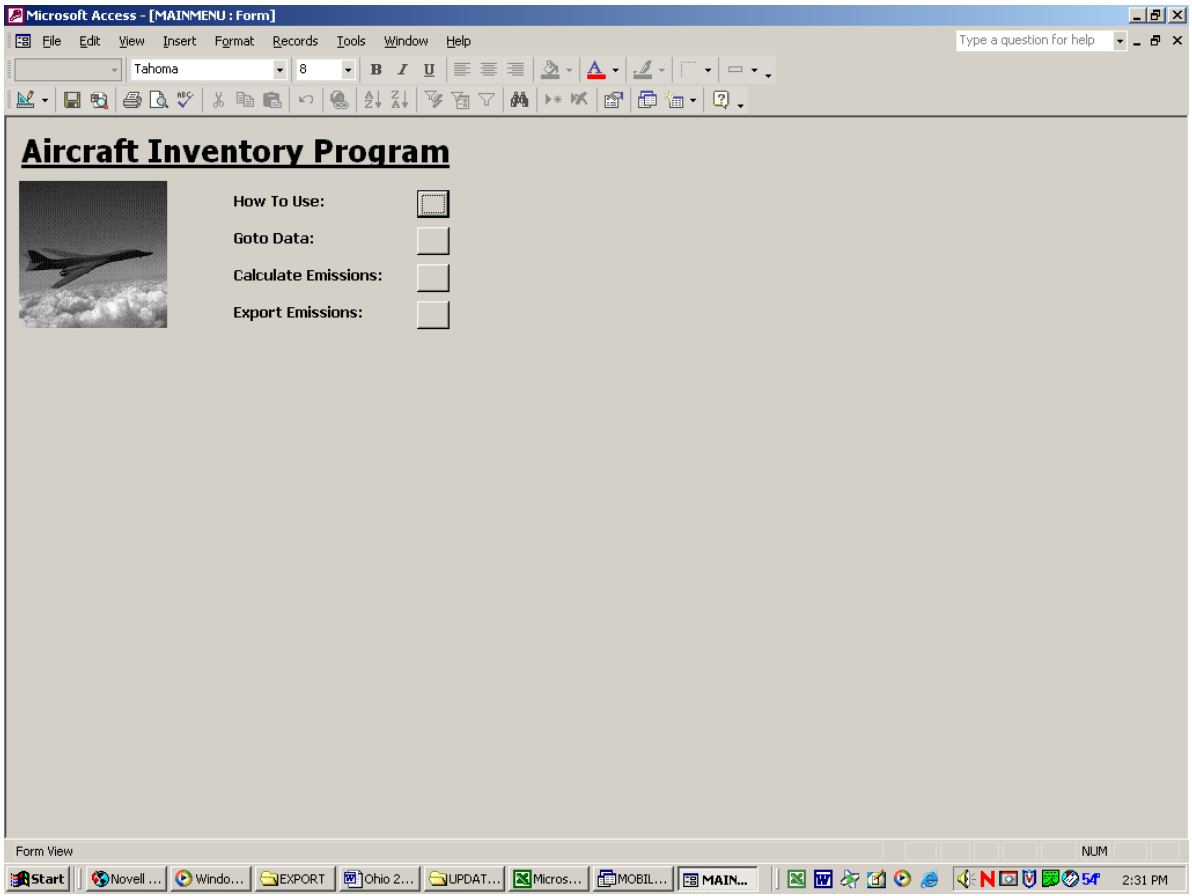
The first aircraft emission inventory submitted to LADCO in April, 2007 contained an error. The inventory submitted in May, 2007 has the error corrected. The error was the result of a carry-over function in Access that picked up the number of operations as instead of LTOs….which made the inventory exactly twice as large as what it really was.

ACCESS CALCULATOR

Introduction:

Our database programmer set up Access application to calculate Ohio's aircraft emission inventory, and export those results to Excel. His utility allows for easy modification of the aircraft data to match future data scenarios. Output to Excel also allows for additional data manipulation and importation.

Interface:



Through this interface the following sets of data can be edited/updated: Airport activity, emission factors, specific airport emissions, state/county FIPS, detailed aircraft information, airport information, and aircraft SCCs. Once the final emissions have been calculated and summed, then the data can be export via the export function on the Main Menu.

Mobile Source Emissions Inventory for Cincinnati PM2.5 Nonattainment Area

Includes a portion of Dearborn County, Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. Emission estimates for the Year 2005, 2008, 2011, 2015, 2018, and 2021 developed in support of the PM2.5 State Implementation Plan

August 2010

Prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency by

OKI Regional Council of Governments

OKI
Ohio · Kentucky · Indiana
Regional Council of Governments

Acknowledgments

Title	Mobile Source Emissions Inventory for Cincinnati PM2.5 Nonattainment Area
Abstract	This report was prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency. The Cincinnati PM2.5 nonattainment area includes a portion of Dearborn County Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. This report includes emission estimates for the years 2005, 2008, 2011, 2015, 2018 and 2021 was generated to support the attainment SIPs for the annual PM2.5 standard. EPA's Motor Vehicle Emission Simulation (MOVES) 2010 was used to generate the emission rates.
Date	August 2010
Agency	Ohio-Kentucky-Indiana Regional Council of Governments Mark Policinski, Executive Director Robert Koehler, P.E., Deputy Director
Project Manager	Andrew J. Reser, AICP
Project Staff	Harikishan Perugu, PTP Larry Buckler

The preparation of this document was financed cooperatively by the Federal Highway Administration, the Federal Transit Administration, the Commonwealth of Kentucky Transportation Cabinet, the Ohio Department of Transportation, and the units of local and county government in the OKI region. The opinions, findings, and conclusions expressed in this document are those of the OKI Regional Council of Governments and are not necessarily those of the U.S. Department of Transportation. This report does not constitute a standard, specification, or regulation.

MOBILE Source Emissions Inventory for the Cincinnati PM2.5 nonattainment area

This report was prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency. The Cincinnati PM2.5 nonattainment area includes a portion of Dearborn County Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. This report includes emission estimates for the years 2005, 2008, 2011, 2015, 2018 and 2021 was generated to support the attainment SIPs for the annual PM2.5 standard. EPA's Motor Vehicle Emissions Simulator (MOVES) 2010 model was used to generate the vehicle emission rates. In December 2009, MOVES replaced MOBILE6.2 as the EPA's official emission factor model. Technical details on OKI's use of MOVES can be found in the Appendix. The OKI travel demand model version 7.6 was used to generate VMT and speed estimates. MOVES emission rates were generated for direct PM2.5, PM2.5 tirewear, PM2.5 brakewear, NO_x and SO^2.

OKI, as the MPO, is responsible for transportation planning and air quality/transportation conformity. Transportation conformity is a mechanism to ensure that federal funding and approval are given to those transportation activities that are consistent with the air quality goals of the State Implementation Plans (SIPs) for Indiana, Kentucky and Ohio. The SIPs include an inventory of projected emissions from vehicles. One or more of the analysis years in the projected inventory may be designated as the motor vehicle emissions budget (MVEB). This budget establishes a maximum allowable limit on future emissions from vehicles (mobile sources). OKI's transportation plans and programs must be shown to be in conformity with all SIP provisions. The conformity process is a quantitative analysis, using U.S.EPA's vehicle emissions software (currently MOVES), demonstrating that forecasted regional vehicle emissions do not exceed the established budget.

Table 1 shows daily and annual mobile source emissions for the combined Indiana and Ohio portions of the nonattainment area, as well as the Kentucky portion of the nonattainment area. Separate MVEB's are typically designated for these two areas. Although official federal guidance on the use of MOVES for PM2.5 SIP development was not available at the time of this analysis, the Federal Highway Administration (FHWA) along with state and local air quality staff were consulted periodically throughout the development of these emissions. An additional safety margin should be added to the MVEB's due uncertainty with growth assumptions utilized in the OKI travel demand model and uncertainty regarding the use of MOVES. Daily and annual mobile source emissions for each county in the nonattainment area are shown in Table 2.

Table 1. Mobile Source Emissions for the Cincinnati PM2.5 Nonattainment Area (tons)

Year	Pollutant Name	DailyEmissions	AnnualEmissions

Kentucky Portion of NA Area

2005 Vehicle Population: 364,081 Daily VMT: 9,621,110 Annual VMT: 3,289,109,202

Oxides of Nitrogen	39.10	13,496.54
Primary Exhaust PM2.5 - Total	1.36	466.23
Primary PM2.5 - Brakewear Particulate	0.16	54.04
Primary PM2.5 - Tirewear Particulate	0.05	17.52
Sulfur Dioxide (SO2)	0.12	41.46

2008 Vehicle Population: 375,873 Daily VMT: 9,991,179 Annual VMT: 3,425,339,505

Oxides of Nitrogen	37.91	13,114.20
Primary Exhaust PM2.5 - Total	1.64	562.84
Primary PM2.5 - Brakewear Particulate	0.18	62.10
Primary PM2.5 - Tirewear Particulate	0.06	20.70
Sulfur Dioxide (SO2)	0.12	42.74

2011 Vehicle Population: 381,911 Daily VMT: 10,490,143 Annual VMT: 3,587,796,186

Oxides of Nitrogen	29.33	10,141.52
Primary Exhaust PM2.5 - Total	1.19	407.74
Primary PM2.5 - Brakewear Particulate	0.20	68.38
Primary PM2.5 - Tirewear Particulate	0.07	22.68
Sulfur Dioxide (SO2)	0.13	45.36

2015 Vehicle Population: 394,278 Daily VMT: 11,495,496 Annual VMT: 3,931,385,741

Oxides of Nitrogen	20.18	6,996.21
Primary Exhaust PM2.5 - Total	0.78	267.30
Primary PM2.5 - Brakewear Particulate	0.23	77.94
Primary PM2.5 - Tirewear Particulate	0.08	25.88
Sulfur Dioxide (SO2)	0.15	50.50

2018 Vehicle Population: 403,817 Daily VMT: 12,173,549 Annual VMT: 4,163,203,435

Oxides of Nitrogen	15.78	5,480.81
Primary Exhaust PM2.5 - Total	0.59	202.15
Primary PM2.5 - Brakewear Particulate	0.27	91.15
Primary PM2.5 - Tirewear Particulate	0.09	30.09
Sulfur Dioxide (SO2)	0.16	56.28

2021 Vehicle Population: 413,587 Daily VMT: 12,534,236 Annual VMT: 4,286,834,360

Oxides of Nitrogen	12.75	4,435.96
Primary Exhaust PM2.5 - Total	0.43	146.79
Primary PM2.5 - Brakewear Particulate	0.28	96.84
Primary PM2.5 - Tirewear Particulate	0.09	31.74
Sulfur Dioxide (SO2)	0.17	58.63

Year	Pollutant Name	DailyEmissions	AnnualEmissions

Ohio/Indiana Portion of NA Area

2005 Vehicle Population: 1,754,582 Daily VMT: 39,564,030 Annual VMT: 13,541,324,003

Oxides of Nitrogen	168.89	58,423.36
Primary Exhaust PM2.5 - Total	5.74	1,979.63
Primary PM2.5 - Brakewear Particulate	0.65	223.20
Primary PM2.5 - Tirewear Particulate	0.20	69.67
Sulfur Dioxide (SO2)	0.48	165.35

2008 Vehicle Population: 1,811,406 Daily VMT: 40,858,751 Annual VMT: 14,015,754,874

Oxides of Nitrogen	148.02	51,357.02
Primary Exhaust PM2.5 - Total	4.85	1,675.04
Primary PM2.5 - Brakewear Particulate	0.80	273.84
Primary PM2.5 - Tirewear Particulate	0.25	85.37
Sulfur Dioxide (SO2)	0.54	185.13

2011 Vehicle Population: 1,840,505 Daily VMT: 42,044,841 Annual VMT: 14,383,526,419

Oxides of Nitrogen	135.95	47,061.53
Primary Exhaust PM2.5 - Total	5.54	1,904.61
Primary PM2.5 - Brakewear Particulate	0.85	290.00
Primary PM2.5 - Tirewear Particulate	0.27	91.52
Sulfur Dioxide (SO2)	0.53	182.01

2015 Vehicle Population: 1,900,111 Daily VMT: 43,316,281 Annual VMT: 14,830,453,053

Oxides of Nitrogen	89.45	31,064.21
Primary Exhaust PM2.5 - Total	3.57	1,227.86
Primary PM2.5 - Brakewear Particulate	0.82	280.25
Primary PM2.5 - Tirewear Particulate	0.26	90.54
Sulfur Dioxide (SO2)	0.53	182.69

2018 Vehicle Population: 1,946,080 Daily VMT: 45,314,292 Annual VMT: 15,513,701,656

Oxides of Nitrogen	70.34	24,451.43
Primary Exhaust PM2.5 - Total	2.78	958.57
Primary PM2.5 - Brakewear Particulate	0.90	307.39
Primary PM2.5 - Tirewear Particulate	0.29	99.03
Sulfur Dioxide (SO2)	0.57	195.09

2021 Vehicle Population: 1,993,161 Daily VMT: 46,689,707 Annual VMT: 15,521,916,278

Oxides of Nitrogen	55.50	18,911.05
Primary Exhaust PM2.5 - Total	2.10	705.30
Primary PM2.5 - Brakewear Particulate	0.96	320.17
Primary PM2.5 - Tirewear Particulate	0.31	102.89
Sulfur Dioxide (SO2)	0.60	199.14

Table 2. Mobile Source Emissions by County for the Cincinnati PM2.5 Nonattainment Area (tons)

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Indiana

Dearborn NA

2005 Vehicle Population: 24,915 Daily VMT: 578,642 Annual VMT: 196,738,031

Oxides of Nitrogen	2.40	865.46
Primary Exhaust PM2.5 - Total	0.08	29.68
Primary PM2.5 - Brakewear Particulate	0.01	3.28
Primary PM2.5 - Tirewear Particulate	0.00	1.02
Sulfur Dioxide (SO2)	0.01	2.45

2008 Vehicle Population: 25,722 Daily VMT: 587,583 Annual VMT: 199,778,078

Oxides of Nitrogen	2.09	748.81
Primary Exhaust PM2.5 - Total	0.07	24.72
Primary PM2.5 - Brakewear Particulate	0.01	3.94
Primary PM2.5 - Tirewear Particulate	0.00	1.23
Sulfur Dioxide (SO2)	0.01	2.69

2011 Vehicle Population: 26,135 Daily VMT: 605,621 Annual VMT: 205,911,005

Oxides of Nitrogen	1.92	685.40
Primary Exhaust PM2.5 - Total	0.08	27.88
Primary PM2.5 - Brakewear Particulate	0.01	4.19
Primary PM2.5 - Tirewear Particulate	0.00	1.32
Sulfur Dioxide (SO2)	0.01	2.65

2015 Vehicle Population: 26,982 Daily VMT: 657,779 Annual VMT: 223,644,622

Oxides of Nitrogen	1.31	482.33
Primary Exhaust PM2.5 - Total	0.05	19.43
Primary PM2.5 - Brakewear Particulate	0.01	4.32
Primary PM2.5 - Tirewear Particulate	0.00	1.39
Sulfur Dioxide (SO2)	0.01	2.87

2018 Vehicle Population: 27,635 Daily VMT: 684,362 Annual VMT: 232,682,971

Oxides of Nitrogen	1.03	376.85
Primary Exhaust PM2.5 - Total	0.04	15.09
Primary PM2.5 - Brakewear Particulate	0.01	4.70
Primary PM2.5 - Tirewear Particulate	0.00	1.51
Sulfur Dioxide (SO2)	0.01	3.04

2021 Vehicle Population: 28,303 Daily VMT: 706,829 Annual VMT: 240,321,759

Oxides of Nitrogen	0.81	297.95
Primary Exhaust PM2.5 - Total	0.03	11.44
Primary PM2.5 - Brakewear Particulate	0.01	5.05
Primary PM2.5 - Tirewear Particulate	0.00	1.62
Sulfur Dioxide (SO2)	0.01	3.19

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Kentucky

Boone

2005 Vehicle Population: 129,823 Daily VMT: 3,924,117 Annual VMT: 1,273,226,967

Oxides of Nitrogen	14.94	5,126.88
Primary Exhaust PM2.5 - Total	0.52	177.58
Primary PM2.5 - Brakewear Particulate	0.06	20.86
Primary PM2.5 - Tirewear Particulate	0.02	6.77
Sulfur Dioxide (SO2)	0.05	15.91

2008 Vehicle Population: 134,028 Daily VMT: 4,076,584 Annual VMT: 1,350,001,539

Oxides of Nitrogen	14.73	5,067.94
Primary Exhaust PM2.5 - Total	0.64	219.29
Primary PM2.5 - Brakewear Particulate	0.07	24.42
Primary PM2.5 - Tirewear Particulate	0.02	8.14
Sulfur Dioxide (SO2)	0.05	16.71

2011 Vehicle Population: 136,181 Daily VMT: 4,383,716 Annual VMT: 1,448,879,491

Oxides of Nitrogen	11.61	3,990.01
Primary Exhaust PM2.5 - Total	0.48	162.47
Primary PM2.5 - Brakewear Particulate	0.08	27.55
Primary PM2.5 - Tirewear Particulate	0.03	9.14
Sulfur Dioxide (SO2)	0.05	18.16

2015 Vehicle Population: 140,590 Daily VMT: 4,950,741 Annual VMT: 1,628,041,282

Oxides of Nitrogen	8.11	2,788.45
Primary Exhaust PM2.5 - Total	0.32	108.49
Primary PM2.5 - Brakewear Particulate	0.09	32.17
Primary PM2.5 - Tirewear Particulate	0.03	10.69
Sulfur Dioxide (SO2)	0.06	20.67

2018 Vehicle Population: 143,991 Daily VMT: 5,260,102 Annual VMT: 1,729,595,156

Oxides of Nitrogen	6.34	2,182.28
Primary Exhaust PM2.5 - Total	0.24	82.19
Primary PM2.5 - Brakewear Particulate	0.11	37.76
Primary PM2.5 - Tirewear Particulate	0.04	12.47
Sulfur Dioxide (SO2)	0.07	23.14

2021 Vehicle Population: 147,476 Daily VMT: 5,478,224 Annual VMT: 1,800,571,684

Oxides of Nitrogen	5.14	1,772.72
Primary Exhaust PM2.5 - Total	0.18	60.19
Primary PM2.5 - Brakewear Particulate	0.12	40.56
Primary PM2.5 - Tirewear Particulate	0.04	13.30
Sulfur Dioxide (SO2)	0.07	24.37

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Campbell				
	2005	Vehicle Population: 86,065	Daily VMT: 2,286,217	Annual VMT: 741,790,595
		Oxides of Nitrogen	8.87	3,041.21
		Primary Exhaust PM2.5 - Total	0.31	104.22
		Primary PM2.5 - Brakewear Particulate	0.04	12.14
		Primary PM2.5 - Tirewear Particulate	0.01	3.94
		Sulfur Dioxide (SO2)	0.03	9.30
	2008	Vehicle Population: 88,853	Daily VMT: 2,339,542	Annual VMT: 774,762,718
		Oxides of Nitrogen	8.63	2,988.33
		Primary Exhaust PM2.5 - Total	0.37	127.73
		Primary PM2.5 - Brakewear Particulate	0.04	14.05
		Primary PM2.5 - Tirewear Particulate	0.01	4.68
		Sulfur Dioxide (SO2)	0.03	9.69
	2011	Vehicle Population: 90,279	Daily VMT: 2,421,600	Annual VMT: 800,372,692
		Oxides of Nitrogen	6.61	2,287.81
		Primary Exhaust PM2.5 - Total	0.27	91.36
		Primary PM2.5 - Brakewear Particulate	0.04	15.26
		Primary PM2.5 - Tirewear Particulate	0.01	5.06
		Sulfur Dioxide (SO2)	0.03	10.15
	2015	Vehicle Population: 93,204	Daily VMT: 2,663,159	Annual VMT: 875,774,487
		Oxides of Nitrogen	4.55	1,570.14
		Primary Exhaust PM2.5 - Total	0.17	59.30
		Primary PM2.5 - Brakewear Particulate	0.05	17.31
		Primary PM2.5 - Tirewear Particulate	0.02	5.75
		Sulfur Dioxide (SO2)	0.03	11.21
	2018	Vehicle Population: 95,458	Daily VMT: 2,771,476	Annual VMT: 911,300,097
		Oxides of Nitrogen	3.52	1,216.21
		Primary Exhaust PM2.5 - Total	0.13	44.14
		Primary PM2.5 - Brakewear Particulate	0.06	19.90
		Primary PM2.5 - Tirewear Particulate	0.02	6.57
		Sulfur Dioxide (SO2)	0.04	12.28
	2021	Vehicle Population: 97,768	Daily VMT: 2,849,127	Annual VMT: 936,445,352
		Oxides of Nitrogen	2.84	985.28
		Primary Exhaust PM2.5 - Total	0.09	32.07
		Primary PM2.5 - Brakewear Particulate	0.06	21.10
		Primary PM2.5 - Tirewear Particulate	0.02	6.92
		Sulfur Dioxide (SO2)	0.04	12.77

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Kenton				
	2005	Vehicle Population: 148,193	Daily VMT: 3,927,743	Annual VMT: 1,274,091,641
		Oxides of Nitrogen	15.29	5,328.44
		Primary Exhaust PM2.5 - Total	0.53	184.43
		Primary PM2.5 - Brakewear Particulate	0.06	21.04
		Primary PM2.5 - Tirewear Particulate	0.02	6.82
		Sulfur Dioxide (SO2)	0.05	16.24
	2008	Vehicle Population: 152,992	Daily VMT: 3,927,332	Annual VMT: 1,300,575,248
		Oxides of Nitrogen	14.55	5,057.93
		Primary Exhaust PM2.5 - Total	0.62	215.81
		Primary PM2.5 - Brakewear Particulate	0.07	23.63
		Primary PM2.5 - Tirewear Particulate	0.02	7.87
		Sulfur Dioxide (SO2)	0.05	16.34
	2011	Vehicle Population: 155,451	Daily VMT: 4,049,886	Annual VMT: 1,338,544,003
		Oxides of Nitrogen	11.11	3,863.70
		Primary Exhaust PM2.5 - Total	0.45	153.90
		Primary PM2.5 - Brakewear Particulate	0.07	25.57
		Primary PM2.5 - Tirewear Particulate	0.02	8.48
		Sulfur Dioxide (SO2)	0.05	17.05
	2015	Vehicle Population: 160,484	Daily VMT: 4,341,124	Annual VMT: 1,427,569,972
		Oxides of Nitrogen	7.51	2,637.63
		Primary Exhaust PM2.5 - Total	0.29	99.51
		Primary PM2.5 - Brakewear Particulate	0.08	28.45
		Primary PM2.5 - Tirewear Particulate	0.03	9.44
		Sulfur Dioxide (SO2)	0.05	18.62
	2018	Vehicle Population: 164,368	Daily VMT: 4,629,694	Annual VMT: 1,522,308,182
		Oxides of Nitrogen	5.93	2,082.32
		Primary Exhaust PM2.5 - Total	0.22	75.82
		Primary PM2.5 - Brakewear Particulate	0.10	33.49
		Primary PM2.5 - Tirewear Particulate	0.03	11.04
		Sulfur Dioxide (SO2)	0.06	20.86
	2021	Vehicle Population: 168,343	Daily VMT: 4,715,306	Annual VMT: 1,549,817,325
		Oxides of Nitrogen	4.76	1,677.96
		Primary Exhaust PM2.5 - Total	0.16	54.53
		Primary PM2.5 - Brakewear Particulate	0.10	35.19
		Primary PM2.5 - Tirewear Particulate	0.03	11.52
		Sulfur Dioxide (SO2)	0.06	21.48

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Ohio

Butler

2005 Vehicle Population: 401,759 Daily VMT: 7,452,293 Annual VMT: 2,469,168,490

Oxides of Nitrogen	32.00	10,910.37
Primary Exhaust PM2.5 - Total	1.06	361.06
Primary PM2.5 - Brakewear Particulate	0.12	40.31
Primary PM2.5 - Tirewear Particulate	0.04	12.60
Sulfur Dioxide (SO2)	0.09	30.01

2008 Vehicle Population: 414,771 Daily VMT: 7,745,693 Annual VMT: 2,598,061,793

Oxides of Nitrogen	28.56	9,803.70
Primary Exhaust PM2.5 - Total	0.91	311.45
Primary PM2.5 - Brakewear Particulate	0.15	50.45
Primary PM2.5 - Tirewear Particulate	0.05	15.74
Sulfur Dioxide (SO2)	0.10	34.25

2011 Vehicle Population: 421,434 Daily VMT: 8,050,709 Annual VMT: 2,693,718,927

Oxides of Nitrogen	26.50	9,074.89
Primary Exhaust PM2.5 - Total	1.05	356.91
Primary PM2.5 - Brakewear Particulate	0.16	53.99
Primary PM2.5 - Tirewear Particulate	0.05	17.06
Sulfur Dioxide (SO2)	0.10	34.00

2015 Vehicle Population: 435,082 Daily VMT: 8,361,495 Annual VMT: 2,792,190,918

Oxides of Nitrogen	17.64	6,064.61
Primary Exhaust PM2.5 - Total	0.68	231.78
Primary PM2.5 - Brakewear Particulate	0.16	52.42
Primary PM2.5 - Tirewear Particulate	0.05	16.96
Sulfur Dioxide (SO2)	0.10	34.28

2018 Vehicle Population: 445,608 Daily VMT: 8,806,051 Annual VMT: 2,940,852,857

Oxides of Nitrogen	13.98	4,813.27
Primary Exhaust PM2.5 - Total	0.54	182.29
Primary PM2.5 - Brakewear Particulate	0.17	57.91
Primary PM2.5 - Tirewear Particulate	0.06	18.68
Sulfur Dioxide (SO2)	0.11	36.85

2021 Vehicle Population: 456,389 Daily VMT: 9,150,040 Annual VMT: 2,966,040,396

Oxides of Nitrogen	11.13	3,757.91
Primary Exhaust PM2.5 - Total	0.41	135.39
Primary PM2.5 - Brakewear Particulate	0.19	60.81
Primary PM2.5 - Tirewear Particulate	0.06	19.56
Sulfur Dioxide (SO2)	0.12	37.90

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Clermont

2005 Vehicle Population: 232,380 Daily VMT: 5,083,336 Annual VMT: 1,684,261,582

Oxides of Nitrogen	21.21	7,295.87
Primary Exhaust PM2.5 - Total	0.72	245.48
Primary PM2.5 - Brakewear Particulate	0.08	27.67
Primary PM2.5 - Tirewear Particulate	0.03	8.64
Sulfur Dioxide (SO2)	0.06	20.51

2008 Vehicle Population: 239,906 Daily VMT: 5,262,494 Annual VMT: 1,765,146,867

Oxides of Nitrogen	18.81	6,516.40
Primary Exhaust PM2.5 - Total	0.61	211.40
Primary PM2.5 - Brakewear Particulate	0.10	34.46
Primary PM2.5 - Tirewear Particulate	0.03	10.74
Sulfur Dioxide (SO2)	0.07	23.32

2011 Vehicle Population: 243,760 Daily VMT: 5,489,550 Annual VMT: 1,836,770,645

Oxides of Nitrogen	17.48	6,039.51
Primary Exhaust PM2.5 - Total	0.71	243.25
Primary PM2.5 - Brakewear Particulate	0.11	37.00
Primary PM2.5 - Tirewear Particulate	0.03	11.68
Sulfur Dioxide (SO2)	0.07	23.23

2015 Vehicle Population: 251,654 Daily VMT: 5,687,704 Annual VMT: 1,899,319,930

Oxides of Nitrogen	11.54	3,993.63
Primary Exhaust PM2.5 - Total	0.46	156.92
Primary PM2.5 - Brakewear Particulate	0.11	35.82
Primary PM2.5 - Tirewear Particulate	0.03	11.58
Sulfur Dioxide (SO2)	0.07	23.34

2018 Vehicle Population: 257,742 Daily VMT: 5,952,609 Annual VMT: 1,987,922,558

Oxides of Nitrogen	9.09	3,146.47
Primary Exhaust PM2.5 - Total	0.36	122.57
Primary PM2.5 - Brakewear Particulate	0.12	39.31
Primary PM2.5 - Tirewear Particulate	0.04	12.67
Sulfur Dioxide (SO2)	0.07	24.94

2021 Vehicle Population: 263,978 Daily VMT: 6,186,447 Annual VMT: 2,005,373,961

Oxides of Nitrogen	7.22	2,449.31
Primary Exhaust PM2.5 - Total	0.27	90.84
Primary PM2.5 - Brakewear Particulate	0.12	41.28
Primary PM2.5 - Tirewear Particulate	0.04	13.27
Sulfur Dioxide (SO2)	0.08	25.66

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Hamilton				
	2005	Vehicle Population: 862,422	Daily VMT: 21,859,473	Annual VMT: 7,241,536,812
		Oxides of Nitrogen	89.30	31,127.09
		Primary Exhaust PM2.5 - Total	3.06	1,064.67
		Primary PM2.5 - Brakewear Particulate	0.35	119.94
		Primary PM2.5 - Tirewear Particulate	0.11	37.41
		Sulfur Dioxide (SO2)	0.26	88.85
	2008	Vehicle Population: 890,352	Daily VMT: 22,124,524	Annual VMT: 7,421,012,594
		Oxides of Nitrogen	77.45	27,020.93
		Primary Exhaust PM2.5 - Total	2.56	889.81
		Primary PM2.5 - Brakewear Particulate	0.42	145.42
		Primary PM2.5 - Tirewear Particulate	0.13	45.31
		Sulfur Dioxide (SO2)	0.28	98.30
	2011	Vehicle Population: 904,655	Daily VMT: 22,426,043	Annual VMT: 7,503,619,525
		Oxides of Nitrogen	70.18	24,435.59
		Primary Exhaust PM2.5 - Total	2.88	997.06
		Primary PM2.5 - Brakewear Particulate	0.44	151.73
		Primary PM2.5 - Tirewear Particulate	0.14	47.86
		Sulfur Dioxide (SO2)	0.28	95.30
	2015	Vehicle Population: 933,953	Daily VMT: 22,849,516	Annual VMT: 7,630,239,650
		Oxides of Nitrogen	45.58	15,925.19
		Primary Exhaust PM2.5 - Total	1.83	634.62
		Primary PM2.5 - Brakewear Particulate	0.42	144.67
		Primary PM2.5 - Tirewear Particulate	0.14	46.71
		Sulfur Dioxide (SO2)	0.27	94.43
	2018	Vehicle Population: 956,548	Daily VMT: 23,630,577	Annual VMT: 7,891,625,119
		Oxides of Nitrogen	35.51	12,422.37
		Primary Exhaust PM2.5 - Total	1.41	490.62
		Primary PM2.5 - Brakewear Particulate	0.45	156.90
		Primary PM2.5 - Tirewear Particulate	0.15	50.52
		Sulfur Dioxide (SO2)	0.29	99.78
	2021	Vehicle Population: 979,689	Daily VMT: 24,098,721	Annual VMT: 7,811,745,310
		Oxides of Nitrogen	27.80	9,530.16
		Primary Exhaust PM2.5 - Total	1.06	357.87
		Primary PM2.5 - Brakewear Particulate	0.48	161.69
		Primary PM2.5 - Tirewear Particulate	0.15	51.92
		Sulfur Dioxide (SO2)	0.30	100.82

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Warren				
	2005	Vehicle Population: 233,106	Daily VMT: 5,884,222	Annual VMT: 1,949,619,088
		Oxides of Nitrogen	23.98	8,224.57
		Primary Exhaust PM2.5 - Total	0.82	278.74
		Primary PM2.5 - Brakewear Particulate	0.09	32.00
		Primary PM2.5 - Tirewear Particulate	0.03	10.00
		Sulfur Dioxide (SO2)	0.07	23.54
	2008	Vehicle Population: 240,655	Daily VMT: 6,057,344	Annual VMT: 2,031,755,542
		Oxides of Nitrogen	21.11	7,267.18
		Primary Exhaust PM2.5 - Total	0.69	237.65
		Primary PM2.5 - Brakewear Particulate	0.12	39.57
		Primary PM2.5 - Tirewear Particulate	0.04	12.34
		Sulfur Dioxide (SO2)	0.08	26.57
	2011	Vehicle Population: 244,521	Daily VMT: 6,406,290	Annual VMT: 2,143,506,318
		Oxides of Nitrogen	19.88	6,826.15
		Primary Exhaust PM2.5 - Total	0.82	279.53
		Primary PM2.5 - Brakewear Particulate	0.13	43.09
		Primary PM2.5 - Tirewear Particulate	0.04	13.60
		Sulfur Dioxide (SO2)	0.08	26.83
	2015	Vehicle Population: 252,440	Daily VMT: 6,842,835	Annual VMT: 2,285,057,933
		Oxides of Nitrogen	13.37	4,598.44
		Primary Exhaust PM2.5 - Total	0.54	185.12
		Primary PM2.5 - Brakewear Particulate	0.13	43.02
		Primary PM2.5 - Tirewear Particulate	0.04	13.91
		Sulfur Dioxide (SO2)	0.08	27.77
	2018	Vehicle Population: 258,547	Daily VMT: 7,368,042	Annual VMT: 2,460,618,151
		Oxides of Nitrogen	10.73	3,692.47
		Primary Exhaust PM2.5 - Total	0.43	148.00
		Primary PM2.5 - Brakewear Particulate	0.14	48.57
		Primary PM2.5 - Tirewear Particulate	0.05	15.66
		Sulfur Dioxide (SO2)	0.09	30.49
	2021	Vehicle Population: 264,802	Daily VMT: 7,707,508	Annual VMT: 2,498,434,852
		Oxides of Nitrogen	8.54	2,875.72
		Primary Exhaust PM2.5 - Total	0.33	109.76
		Primary PM2.5 - Brakewear Particulate	0.16	51.34
		Primary PM2.5 - Tirewear Particulate	0.05	16.51
		Sulfur Dioxide (SO2)	0.10	31.58

Mobile Source Emission Forecast Process

Emission Factor Model

OKI's conformity assessment utilized U.S.EPA's emissions model MOVES 2010 to develop emission factors for SO2, NO_X and PM2.5. Table 3 summarizes the settings used in the MOVES run specification file. Table 4 lists the data used in the MOVES County-Data Manager. Further details on the use of MOVES are found in the Appendix.

Table 3.

MOVES Runspec [sic] Parameter	Settings
MOVES Version 2009/12/21, MOVES default database 2010615111524	
Scale	County, Emission Rates
Time Span	Time aggregation = Hour 1 month representing average annual temperatures All hours of day selected Weekdays only
Geographic Bounds	2 Custom Domains – 4 Ohio counties, 3 Kentucky counties
Vehicles/Equipment	All source types, gasoline and diesel
Road Type	All road types including off-network
Pollutants and Processes	NO_x, All PM2.5 categories, SO^2, Total Energy Consumption
Strategies	none
General Output	Units= grams, joules and miles
Output Emissions	Time = hour, Location =county, on-road emission rates by road type and source use type.
Advanced Performance	none

Table 4

County Data Manager	Data Source
Source Type Population	Local and default. Local data (2010) from KYTC and ODOT from motor vehicle registration data. Default data used for source types 41, 61 and 62. In addition , default data for source types 31, 32 and 54 used for KY.
Vehicle Type VMT	Local and default. HPMSVTypeYear VMT=daily VMT from OKI travel demand model with EPA's daily to annual VMT converter applied. monthVMTFraction = default. dayVMTFraction=default, hourVMTFraction=local.
I/M Programs	Default modified to reflect discontinued I/M program
Fuel Formulation	Default

Fuel Supply	Default
Meteorology Data	Local. Kentucky Division for Air Quality.
Ramp Fraction	Local. Ramp emissions calculated outside of MOVES
Road Type Distribution	Local. OKI travel demand model.
Age Distribution	Local and default. Local data (2010) from KYTC and ODOT from motor vehicle registration data. Default data used for source types 41, 61 and 62. In addition , default data for source types 31, 32 and 54 used for KY.
Average Speed Distribution	Local. OKI travel demand model.

OKI Travel Demand Model

Transportation system performance was estimated using the OKI Travel Demand Model Version 7.6. The OKI Travel Demand Model is composed of TRANPLAN programs, CUBE Voyager programs and a series of FORTRAN programs written by OKI. It is a state of the practice model that uses the standard 4 phase sequential modeling approach of trip generation, distribution, modal choice and assignment. The model uses demographic and land use data and capacity and free-flow speed characteristics for each roadway segment in the network to produce a "loaded" highway network with forecasted traffic volumes with revised speeds based on specified speed/capacity relationships.

Travel analysis zones are the basic geographic unit for estimating travel in the OKI model. The OKI region is subdivided into 1608 traffic analysis zones to permit detail as well as manageability. A variety of socioeconomic data items are used in the OKI transportation planning process. These data are used primarily to forecast future travel patterns by serving as independent variables in OKI trip generation equations. The following categories of planning data are utilized:

- Population (household and group quarter)
- Households
- Household vehicles
- Employment (by employment category and zone of work)
- Labor force participation (by zone of residence)
- Area type

The principal data requirements of the OKI travel demand forecasting model are population and employment. From these variables, other characteristics including households, labor force, and personal vehicles may be derived. Chapter 5 of *OKI 2030 Regional Transportation Plan 2008 Update* provides a complete demographic overview of the region.

OKI utilizes both base year (2005) and future year data (2010, 2020 and 2030) in the planning process. Planning data are maintained at the Traffic Analysis Zone (TAZ) level, and originate in the 2000 Census of Population and Housing. Base year 2005 and future year data for each variable are developed through various methods. More detailed explanation of base year and future year data generation for each of the above-mentioned categories of planning data follows. All of the variables represent the latest OKI planning assumptions.

Population

Base and Future Year Data: Population data for base year 2005 and future years 2010, 2020 and 2030 originate with the 2000 Census of Population and Housing. Utilizing ArcView GIS, population data at the zonal level for 2000 was derived from the area proportion allocation of block level population.

As a tri-state regional planning agency, OKI uses county level projections as prepared by the respective state data centers (Ohio Department of Development Office of Strategic Research, Kentucky State Data Center and Indiana Business Research Center) as control totals. The most current projections (years 2005 to 2030) were released by the Ohio and Indiana state data centers in 2003 and the Kentucky State Data Center in 2004. Population projections at the zonal level are calculated by multiplying household size by the projected zonal households. Household size is factored so that, in each county, the sum of the zonal populations equals the control total.

Households

Base Year Data: Household data for base year 2005 originates with the 2000 Census of Population and Housing. Utilizing the geographic information system ArcMap, household data at the zonal level for 2000 was derived from the area proportion allocation of block level households. Year 2000 household data was updated to 2005 with residential building permits issued between January 2000 and December 2004. The residential building locations were geocoded in ArcMap, then aggregated to the TAZs. The housing unit totals for each TAZ were converted to households by applying a vacancy rate, an adjustment for permitted but unbuilt units, and subtracting demolitions (where data was available). These households were then added to the year Census 2000 zonal household total to arrive at 2005 households for each TAZ.

Future Year Data: The preparation of household projections was accomplished by calculating the number of households for a projected county population using ratios of householders to total population by age specific cohorts derived from the 2000 Census for each analysis year. Disaggregation to TAZs was determined by historical trends, existing and future land use, topography, flood plain information, availability of land, local knowledge and other factors.

Household Vehicles

Base and Future Year Data: Base and future year household vehicle data were obtained from the 2000 Census of Population and Housing. The 2000 Census is the only source of household vehicle data available at the block group level. Average vehicles per household were calculated for block groups then applied to the TAZs associated with each block group. The 2005, 2010, 2020 and 2030 vehicles per household level was held at the 2000 level based on the fact that, since 2002, the number of vehicles per household has exceeded the number of drivers per household.

Labor Force

Base and Future Year Data: The OKI labor force is a function of the population as determined by a labor force participation ratio (the number of employed persons in the labor force per persons 16 and over). Household data for base year 2005 originates with the 2000 Census of Population and Housing. Utilizing

the geographic information system ArcMap, household data at the zonal level for 2000 was derived from the area proportion allocation of block group level employed labor force. The labor force projections for 2005, 2010, 2020 and 2030 were based on the most recent projections of national labor force participation rates by age and sex cohorts from the U.S. Department of Labor, Bureau of Labor Statistics for each of those years. These rates were then applied to the projected county age/sex cohorts and adjusted to eliminate the unemployed to arrive at a county employed labor force control total. Employed labor force at the zonal level is calculated by multiplying the labor force participation rate by the zonal population. The labor force participation rate is adjusted so that, in each county, the sum of the zonal labor force counts equals the control total.

Employment

Base Year Data: Quarterly Census of Employment and Wages (QCEW or ES202) data for 2005 was utilized as the primary tool to calculate employment at the zonal level. Individual business records containing physical location, number of employees and SIC code were geocoded through ArcMap and aggregated to the TAZ level. This data set was supplemented by other sources of data to complete the commuting employment picture in the OKI region. Each zone's employment was divided according to the SIC code into three classes (retail, office, industrial) based upon the potential for generating trips.

Future Year Data: For future year employment projection, calculation was first made of the employment at the regional level. At the regional level, employment is a calculation of the region's employed labor force minus workers who live in the region but commute out to work, plus workers who live outside the region but commute in to work. The regional total was disaggregated first to the county level based on historic trends and expected changes in the county's share of the region's employment and then to the TAZ level. Disaggregation to TAZs was determined by historical trends, existing and future land use, topography, flood plain information, availability of land, local knowledge and other factors.

Area Type

Base and Future Year Data: For each analysis year, each TAZ is assigned an area type designation as CBD, Urban, Suburban or Rural based on population and employment densities.

Model Calibration

OKI's Travel Demand Model has been validated to observed traffic volumes for the model base year 2005. The modeling network encompasses the entire ozone nonattainment area with the exception of Clinton County, Ohio. The modeling network also includes Greene, Miami and Montgomery counties in Ohio and the remainder of Dearborn County Indiana. The difference between estimated vehicle miles traveled (VMT) and 2005 observed VMT is less than 1%. A highway screenline analysis compares the screenline observed and simulated traffic volume discrepancies with the ODOT standard of maximum desirable deviation. The comparison shows that the model performs at a satisfactory level and all the errors were under the ODOT curve. Further information can be found in OKI's 2007 report, "*OKI/MVRPC Travel Demand Model Methodology/ Validation Report*". For the calibration, OKI used over 3000 traffic counts collected through 2006 by the Ohio Department of Transportation (ODOT), the Kentucky

Transportation Cabinet, many county and local governments, transportation engineering consultants, and OKI. These traffic counts cover nearly 50% percent of the links in the OKI portion of the modeling network. The methodology provides consistency with past emission inventory and conformity analysis work performed by OKI.

Local Inputs and Post-Model Processing

OKI incorporates a variety of sources of local data to both improve and confirm the accuracy of VMT, as well as other travel-related parameters. Free flow speeds used on the highway and transit networks are based on travel time studies performed locally. The OKI post-processing program, IMPACT, uses the loaded highway network to generate VMT by hour, VMT by speed distribution and VMT by facility type. These tables are then included as input into MOVES. Two separate sets of VMT tables are generated: one for the four Ohio counties plus Dearborn County Indiana, and a second for the three Kentucky counties. The VMT by hour tables utilize hourly traffic distribution and directional split factors for different roadway types as developed by OKI. The main source of the data was the permanent traffic counting stations located throughout the OKI region for the years of 1998-2002. This data was supplemented with data collected at coverage count stations (locations with counts taken on only one-two days). The stations were classified by area type: urban and rural, and functional classification: freeway, arterial and collector. Speeds representing various "loaded" conditions (with traffic volumes) are estimated using techniques from the 1997 Highway Capacity Manual. This permits the estimation of speeds as conditions vary from hour to hour on the different facility types throughout the region. The IMPACT program performs the appropriate summation by area and roadway type as well as regional totals. OKI has also developed seasonal conversion factors to adjust traffic volumes to summer conditions. The factors were derived from local data collected at permanent traffic counting stations during 1994-1997 utilizing the average daily traffic monthly conversion factors for June, July and August. Further information on OKI's IMPACT program is documented in the report, *"Travel Demand Model Summary Reporting and Impact Summary Reporting: OKI/MVRPC Travel Demand Model User's Guide", OKI 2003.*

APPENDIX

OKI Technical Documentation for Using EPA MOVES to Develop MOBILE Source Emissions

August 2010

1. Using MOVES

To determine specific emission profiles and inventory, user has to define the input data like area, time span, type of vehicles, road types, fuel types, emission producing processes etc. These data are stored in an XML file which is called Runspec [sic]. Using graphical user interface user can modify all these attributes of Runspec [sic]. In the following sections, how input data is entered and modified is explained. All these input options are found in the navigation panel of Graphical User Interface of MOVES software.

1.1 Description

This input tells about the specifications of the Runspec [sic] and it is useful to distinguish between the Runspecs [sic]. We can also explain the brief overview of the particular Runspec [sic]. In all of our current Runspecs [sic], we have details such as analysis years, area and pollutants analyzed.

1.2 Scale

In this option, we need to specify about the Domain/Scale and Calculation type. The Domain specifies the level of default data we need to use for analysis and also the scale of the analysis. We have considered the County scale for Ohio Custom Domain and the calculation type we have used is “Emission Rates”.

1.3 Time Spans

This input panel has different time-related input data like time aggregation level, year of analysis, month of analysis, whether analysis day is Weekday or Weekend, and hours of analysis. In all of our runs, time aggregation level is considered as hour, which is the most disaggregated level possible in MOVES and it is also specified in the technical guidance† for all SIP runs. We have used different years of analysis (i.e. 2005, 2008, 2011, 2015, 2018, and 2021). We have used two different months, July and April. Ozone season daily analysis is done using July temperatures. Annual analysis uses one 24-hour set of average annual temperatures. The annual average minimum temperature, maximum temperature and humidity values for each hour were calculated and assigned the April month ID.

1.4 Geographic Bounds

In this input type, we need to specify about region of analysis (eg. Nation, State, Custom Domain). We have created a separate input database through combining four Ohio counties namely, Hamilton, Butler, Clermont and Warren. Upon selecting the custom domain, MOVES will consider this region as separate Generic County. The state ID is fixed as 99 and we have assigned an arbitrary CountyID 390 for Ohio to distinguish between default county codes. User also need to provide a fraction geographic phase in area, in this case we do not have any phase

in area fraction and we also provided average barometric pressure to identify whether it is low altitude area or high altitude area (the barometric pressures are averages of all constituent counties). Since we do not have I/M program in the region the refueling program adjustment fraction and refueling spill program adjustment fractions are assigned as 0.00. In this input panel we also need to specify the Domain Input Databases. For all of our runs we have defined different input databases for each year.

1.5 Vehicles/Equipment

In MOVES [sic], user also needs to provide the different type of vehicles considered for analysis in the region. MOVES [sic] provide us with 13 different types of vehicles or equipment and four different fuel types and we need to select appropriate fuel and vehicle combinations. In MOVES [sic] vehicle types are called SourceUseTypes [sic]. We have considered all possible types of fuel/vehicle type combinations.

1.6 Road Type

Next input panel is about type of roadways in the region. There are five types of road types available in MOVES, since OKI travel demand model could not predict the VMT in parking lots (off network) only four road types are considered. These road types are relatively simple and are based on area type, whether it is urban or rural. All expressways and freeways are considered as restricted roadways and all other road types are considered as unrestricted roadways.

1.7 Pollutants and Processes

There are different pollutants and corresponding processes are available in MOVES. A separate panel is available for selecting different pollutants and processes. In these particular set of runs, total PM2.5 emissions are selected with an addition of sulfur dioxide. To perform calculation of PM2.5 it is also required to select Total energy consumption. In addition to PM2.5, Oxides of Nitrogen are also selected.

1.8 Miscellaneous

Further, if we have information about future or present Alternative Vehicle Fuels & Technologies, on-road retrofit and rate of progress information that can be given as input to the Runspec [sic]. If we do not specify future Alternative Vehicle Fuel & Technologies, MOVES [sic] is going to assume default alternative fuels. So, we have modified default AVFT through importing new AVFT strategy file which includes there would not be any change in transit bus fuels. MOVES [sic] also provide us the options whether we would like to save the MOVESactivityoutput [sic] and MOVESOutput [sic] databases or not.

Table 1 : Alternative Vehicle and Fueling Technology used in all Runspecs [sic]

sourceTypeID	modelYearID	fuelTypeID	engTechID	fuelEngFraction
42	1960	2	1	1
42	1961	2	1	1
42	1962	2	1	1
42	1963	2	1	1
42	1964	2	1	1
42	1965	2	1	1
42	1966	2	1	1
42	1967	2	1	1
42	1968	2	1	1
42	1969	2	1	1
42	1970	2	1	1
42	1971	2	1	1
42	1972	2	1	1
42	1973	2	1	1
42	1974	2	1	1
42	1975	2	1	1
42	1976	2	1	1
42	1977	2	1	1
42	1978	2	1	1
42	1979	2	1	1
42	1980	2	1	1
42	1981	2	1	1
42	1982	2	1	1
42	1983	2	1	1
42	1984	2	1	1
42	1985	2	1	1
42	1986	2	1	1
42	1987	2	1	1
42	1988	2	1	1
42	1989	2	1	1
42	1990	2	1	1
42	1991	2	1	1
42	1992	2	1	1
42	1993	2	1	1
42	1994	2	1	1
42	1995	2	1	1
42	1996	2	1	1
42	1997	2	1	1
42	1998	2	1	1
42	1999	2	1	1
42	2000	2	1	1
42	2001	2	1	1
42	2002	2	1	1
42	2003	2	1	1
42	2004	2	1	1
42	2005	2	1	1

42	2006	2	1	1
42	2007	2	1	1
42	2008	2	1	1
42	2009	2	1	1
42	2010	2	1	1
42	2011	2	1	1
42	2012	2	1	1
42	2013	2	1	1
42	2014	2	1	1
42	2015	2	1	1
42	2016	2	1	1
42	2017	2	1	1
42	2018	2	1	1
42	2019	2	1	1
42	2020	2	1	1
42	2021	2	1	1
42	2022	2	1	1
42	2023	2	1	1
42	2024	2	1	1
42	2025	2	1	1
42	2026	2	1	1
42	2027	2	1	1
42	2028	2	1	1
42	2029	2	1	1
42	2030	2	1	1
42	2031	2	1	1
42	2032	2	1	1
42	2033	2	1	1
42	2034	2	1	1
42	2035	2	1	1
42	2036	2	1	1
42	2037	2	1	1
42	2038	2	1	1
42	2039	2	1	1
42	2040	2	1	1
42	2041	2	1	1
42	2042	2	1	1
42	2043	2	1	1
42	2044	2	1	1
42	2045	2	1	1
42	2046	2	1	1
42	2047	2	1	1
42	2048	2	1	1
42	2049	2	1	1
42	2050	2	1	1

1.9 Output

In MOVES we need to specify the output database and need to create new database for each new Runspec [sic]. We also have options like specifying the units for emission rates and energy consumption. These options are available in the General Output panel. There is one more option available within the output which is called output emissions detail, which provides user different options for data aggregation.

2. Data Importers

In order to enter local data into Runspec [sic], we need to use pre processing option in the MOVES. We can select either Data Importer or County Importer for Custom Domain option. These Importers convert the data in excel format to MySQL tables. This is the preferred input format of MOVES software.

2.1 Meteorology Data Importer

In this type of Importer, meteorology data is imported a MOVES input format. This dataset has different data items like month ID, Zone ID, hour ID, Temperature and Relative Humidity. For OKI region and Ohio portion runs we have used temperature data obtained from the Kentucky Division for Air Quality (KDAQ). Even though ODOT has provided the temperature data (collected from local airports), KDAQ data appeared to be more applicable. In the data set, April Meteorology data is replaced with annual average temperatures and relative humidity.

Table 2 : Meteorology data obtained from KDAQ

monthID	zoneID	hourID	temperature	relHumidity
4	993900	1	47.5	72.9
4	993900	2	46.4	75.8
4	993900	3	45.5	77.9
4	993900	4	44.8	79.4
4	993900	5	44.3	80.7
4	993900	6	43.7	82.1
4	993900	7	43.2	83.3
4	993900	8	43.6	82.3
4	993900	9	46.1	76.4
4	993900	10	50.1	67.0
4	993900	11	54.2	57.8
4	993900	12	57.7	50.9
4	993900	13	60.8	45.7
4	993900	14	62.5	43.1

4	993900	15	63.1	42.2
4	993900	16	63.2	42.0
4	993900	17	62.8	42.6
4	993900	18	61.7	44.3
4	993900	19	59.7	47.6
4	993900	20	57.1	52.2
4	993900	21	54.5	57.2
4	993900	22	52.2	62.1
4	993900	23	50.6	65.9
4	993900	24	49.1	69.4
7	993900	1	69.3	69.5
7	993900	2	68.1	72.4
7	993900	3	67.1	74.8
7	993900	4	66.4	76.6
7	993900	5	65.9	78
7	993900	6	65.3	79.7
7	993900	7	64.8	81.1
7	993900	8	65.2	79.9
7	993900	9	67.8	73.1
7	993900	10	72	63.4
7	993900	11	76.2	55
7	993900	12	79.8	48.8
7	993900	13	83	44
7	993900	14	84.7	41.6
7	993900	15	85.3	40.8
7	993900	16	85.5	40.6
7	993900	17	85.1	41.2
7	993900	18	83.9	42.8
7	993900	19	81.8	45.8
7	993900	20	79.1	49.9
7	993900	21	76.4	54.6
7	993900	22	74.1	59
7	993900	23	72.5	62.3
7	993900	24	70.8	65.9

2.2 Source Type Population Importer

This importer imports vehicle type, and registered vehicle population in the region into MOVES input databases. ODOT has provided us with the registered vehicle population in each county in the region for 13 MOVES vehicle types. KYTC has provided registered vehicle population by county for 6 HPMS vehicle types. The KYTC data was converted to the 13 MOVES vehicle types based on the Ohio distribution. Same vehicle population was used for all analysis years. As per suggestions made by FHWA and KYTC, the Source Type Population has been forecasted for future years with +0.8 % per year. Similarly, the Source Type Populations has been estimated for past years. The MOVES default source type population for intercity bus, refuse trucks, motor homes and combination trucks was used. In addition, MOVES default source type

population for passenger trucks and light commercial trucks was used for Kentucky. The MOVES default source type population was acquired from the MOVES activity output tables from county-level inventory runs.

Table3 : Source Type Population for Ohio Custom Domain (2008)

yearID	sourceTypeID	sourceTypePopulation
2008	11	68559
2008	21	1191067
2008	31	482420
2008	32	15817
2008	41	454
2008	42	81
2008	43	3651
2008	51	409
2008	52	366
2008	53	361
2008	54	4888
2008	61	4839
2008	62	5548

Table 4: Kentucky Source Type population (acquired from KYTC)

yearID	sourceTypeID	sourceTypePopulation
2008	11	7975
2008	21	197009
2008	31	120518
2008	32	40263
2008	41	127
2008	42	21
2008	43	977
2008	51	115
2008	52	761
2008	53	751
2008	54	1379
2008	61	1580
2008	62	1811

2.3 Age Distribution Importer

For emission calculation the MOVES need vehicle Age Distribution by Source Type. Vehicle Age Distribution is divided into 30 years based on vehicle model years. For each vehicle type, the distribution sum adds up to one. ODOT has obtained vehicle registration data from the Bureau of Motor Vehicles for all the counties in Ohio and processed them to convert into MOVES Age Distribution for 13 vehicle types. We have used the same Age Distribution for all year runs. All

the vehicles older than 30 years are considered as 30-years old. Same age distribution is used for all analysis years. KYTC also provided similar information, but for the 6 HPMS types only. For Kentucky, identical age distributions are used within each HPMS vehicle type.

Table 5 : Ohio Custom Domain Age distribution

Source TypeID	yearID	ageID	ageFraction
11	2008	0	0.0019
11	2008	1	0.0191
11	2008	2	0.0531
11	2008	3	0.0688
11	2008	4	0.0773
11	2008	5	0.0737
11	2008	6	0.0611
11	2008	7	0.0780
11	2008	8	0.0636
11	2008	9	0.0537
11	2008	10	0.0435
11	2008	11	0.0359
11	2008	12	0.0282
11	2008	13	0.0230
11	2008	14	0.0220
11	2008	15	0.0183
11	2008	16	0.0160
11	2008	17	0.0146
11	2008	18	0.0097
11	2008	19	0.0080
11	2008	20	0.0072
11	2008	21	0.0086
11	2008	22	0.0084
11	2008	23	0.0121
11	2008	24	0.0171
11	2008	25	0.0179
11	2008	26	0.0137
11	2008	27	0.0171
11	2008	28	0.0249
11	2008	29	0.0172
11	2008	30	0.0862
21	2008	0	0.0121
21	2008	1	0.0331
21	2008	2	0.0440
21	2008	3	0.0528
21	2008	4	0.0534
21	2008	5	0.0566
21	2008	6	0.0570
21	2008	7	0.0592
21	2008	8	0.0591
21	2008	9	0.0542
21	2008	10	0.0590
21	2008	11	0.0568
21	2008	12	0.0507
21	2008	13	0.0499
21	2008	14	0.0438
21	2008	15	0.0453
21	2008	16	0.0368
21	2008	17	0.0308
21	2008	18	0.0261
21	2008	19	0.0207
21	2008	20	0.0165
21	2008	21	0.0132
21	2008	22	0.0095
21	2008	23	0.0073
21	2008	24	0.0059
21	2008	25	0.0043
21	2008	26	0.0033
21	2008	27	0.0017
21	2008	28	0.0011
21	2008	29	0.0010
21	2008	30	0.0346
31	2008	0	0.0103
31	2008	1	0.0279
31	2008	2	0.0502
31	2008	3	0.0570
31	2008	4	0.0659
31	2008	5	0.0806
31	2008	6	0.0796
31	2008	7	0.0733
31	2008	8	0.0727
31	2008	9	0.0599
31	2008	10	0.0625
31	2008	11	0.0603
31	2008	12	0.0516
31	2008	13	0.0432
31	2008	14	0.0380
31	2008	15	0.0386
31	2008	16	0.0302
31	2008	17	0.0260
31	2008	18	0.0165
31	2008	19	0.0125
31	2008	20	0.0093

31	2008	21	0.0084
31	2008	22	0.0067
31	2008	23	0.0051
31	2008	24	0.0037
31	2008	25	0.0025
31	2008	26	0.0017
31	2008	27	0.0009
31	2008	28	0.0004
31	2008	29	0.0002
31	2008	30	0.0041
32	2008	0	0.0178
32	2008	1	0.0459
32	2008	2	0.0871
32	2008	3	0.0699
32	2008	4	0.0707
32	2008	5	0.0357
32	2008	6	0.0355
32	2008	7	0.0369
32	2008	8	0.0366
32	2008	9	0.0407
32	2008	10	0.0491
32	2008	11	0.0547
32	2008	12	0.0427
32	2008	13	0.0413
32	2008	14	0.0383
32	2008	15	0.0602
32	2008	16	0.0476
32	2008	17	0.0381
32	2008	18	0.0304
32	2008	19	0.0181
32	2008	20	0.0212
32	2008	21	0.0184
32	2008	22	0.0135
32	2008	23	0.0134
32	2008	24	0.0095
32	2008	25	0.0070
32	2008	26	0.0054
32	2008	27	0.0021
32	2008	28	0.0014
32	2008	29	0.0008
32	2008	30	0.0100
41	2008	0	0.0000
41	2008	1	0.0309
41	2008	2	0.0884
41	2008	3	0.0890
41	2008	4	0.0768
41	2008	5	0.0746
41	2008	6	0.0967
41	2008	7	0.0635

41	2008	8	0.0486
41	2008	9	0.0801
41	2008	10	0.0751
41	2008	11	0.0624
41	2008	12	0.0254
41	2008	13	0.0271
41	2008	14	0.0188
41	2008	15	0.0193
41	2008	16	0.0133
41	2008	17	0.0177
41	2008	18	0.0094
41	2008	19	0.0177
41	2008	20	0.0171
41	2008	21	0.0099
41	2008	22	0.0039
41	2008	23	0.0055
41	2008	24	0.0061
41	2008	25	0.0011
41	2008	26	0.0033
41	2008	27	0.0033
41	2008	28	0.0028
41	2008	29	0.0017
41	2008	30	0.0105
42	2008	0	0.0000
42	2008	1	0.0366
42	2008	2	0.1098
42	2008	3	0.0366
42	2008	4	0.1585
42	2008	5	0.0366
42	2008	6	0.0610
42	2008	7	0.0610
42	2008	8	0.0244
42	2008	9	0.1098
42	2008	10	0.0366
42	2008	11	0.0976
42	2008	12	0.0366
42	2008	13	0.0244
42	2008	14	0.0244
42	2008	15	0.0122
42	2008	16	0.0244
42	2008	17	0.0244
42	2008	18	0.0366
42	2008	19	0.0000
42	2008	20	0.0000
42	2008	21	0.0122
42	2008	22	0.0000
42	2008	23	0.0000
42	2008	24	0.0000
42	2008	25	0.0000

42	2008	26	0.0122
42	2008	27	0.0000
42	2008	28	0.0000
42	2008	29	0.0122
42	2008	30	0.0122
43	2008	0	0.0905
43	2008	1	0.0302
43	2008	2	0.0549
43	2008	3	0.0467
43	2008	4	0.0592
43	2008	5	0.0723
43	2008	6	0.0481
43	2008	7	0.0334
43	2008	8	0.0668
43	2008	9	0.0647
43	2008	10	0.0842
43	2008	11	0.0864
43	2008	12	0.0473
43	2008	13	0.0500
43	2008	14	0.0242
43	2008	15	0.0185
43	2008	16	0.0106
43	2008	17	0.0228
43	2008	18	0.0109
43	2008	19	0.0130
43	2008	20	0.0125
43	2008	21	0.0092
43	2008	22	0.0062
43	2008	23	0.0079
43	2008	24	0.0090
43	2008	25	0.0035
43	2008	26	0.0030
43	2008	27	0.0011
43	2008	28	0.0027
43	2008	29	0.0016
43	2008	30	0.0087
51	2008	0	0.0054
51	2008	1	0.0488
51	2008	2	0.0623
51	2008	3	0.0705
51	2008	4	0.0867
51	2008	5	0.0434
51	2008	6	0.0434
51	2008	7	0.0542
51	2008	8	0.0542
51	2008	9	0.0759
51	2008	10	0.0217
51	2008	11	0.0407
51	2008	12	0.0786

51	2008	13	0.0542
51	2008	14	0.0515
51	2008	15	0.0678
51	2008	16	0.0325
51	2008	17	0.0081
51	2008	18	0.0163
51	2008	19	0.0027
51	2008	20	0.0081
51	2008	21	0.0000
51	2008	22	0.0027
51	2008	23	0.0027
51	2008	24	0.0136
51	2008	25	0.0000
51	2008	26	0.0000
51	2008	27	0.0000
51	2008	28	0.0027
51	2008	29	0.0000
51	2008	30	0.0515
52	2008	0	0.0054
52	2008	1	0.0488
52	2008	2	0.0623
52	2008	3	0.0705
52	2008	4	0.0867
52	2008	5	0.0434
52	2008	6	0.0434
52	2008	7	0.0542
52	2008	8	0.0542
52	2008	9	0.0759
52	2008	10	0.0217
52	2008	11	0.0407
52	2008	12	0.0786
52	2008	13	0.0542
52	2008	14	0.0515
52	2008	15	0.0678
52	2008	16	0.0325
52	2008	17	0.0081
52	2008	18	0.0163
52	2008	19	0.0027
52	2008	20	0.0081
52	2008	21	0.0000
52	2008	22	0.0027
52	2008	23	0.0027
52	2008	24	0.0136
52	2008	25	0.0000
52	2008	26	0.0000
52	2008	27	0.0000
52	2008	28	0.0027
52	2008	29	0.0000
52	2008	30	0.0515

53	2008	0	0.0000
53	2008	1	0.0062
53	2008	2	0.0373
53	2008	3	0.0093
53	2008	4	0.0280
53	2008	5	0.0342
53	2008	6	0.0186
53	2008	7	0.0186
53	2008	8	0.0124
53	2008	9	0.0155
53	2008	10	0.0217
53	2008	11	0.0373
53	2008	12	0.0093
53	2008	13	0.0311
53	2008	14	0.0217
53	2008	15	0.0373
53	2008	16	0.0217
53	2008	17	0.0342
53	2008	18	0.0124
53	2008	19	0.0186
53	2008	20	0.0248
53	2008	21	0.0373
53	2008	22	0.0186
53	2008	23	0.0248
53	2008	24	0.0062
53	2008	25	0.0373
53	2008	26	0.0155
53	2008	27	0.0186
53	2008	28	0.0217
53	2008	29	0.0186
53	2008	30	0.3509
54	2008	0	0.0077
54	2008	1	0.0170
54	2008	2	0.0377
54	2008	3	0.0424
54	2008	4	0.0471
54	2008	5	0.0579
54	2008	6	0.0552
54	2008	7	0.0485
54	2008	8	0.0406
54	2008	9	0.0439
54	2008	10	0.0505
54	2008	11	0.0539
54	2008	12	0.0435
54	2008	13	0.0360
54	2008	14	0.0348
54	2008	15	0.0375
54	2008	16	0.0303
54	2008	17	0.0231
54	2008	18	0.0196
54	2008	19	0.0150
54	2008	20	0.0183
54	2008	21	0.0208
54	2008	22	0.0218
54	2008	23	0.0217
54	2008	24	0.0186
54	2008	25	0.0173
54	2008	26	0.0163
54	2008	27	0.0118
54	2008	28	0.0084
54	2008	29	0.0059
54	2008	30	0.0968
61	2008	0	0.0030
61	2008	1	0.0167
61	2008	2	0.0334
61	2008	3	0.0393
61	2008	4	0.0506
61	2008	5	0.0530
61	2008	6	0.0620
61	2008	7	0.0625
61	2008	8	0.0562
61	2008	9	0.0551
61	2008	10	0.0595
61	2008	11	0.0569
61	2008	12	0.0458
61	2008	13	0.0493
61	2008	14	0.0380
61	2008	15	0.0435
61	2008	16	0.0425
61	2008	17	0.0312
61	2008	18	0.0262
61	2008	19	0.0235
61	2008	20	0.0201
61	2008	21	0.0225
61	2008	22	0.0212
61	2008	23	0.0141
61	2008	24	0.0137
61	2008	25	0.0096
61	2008	26	0.0069
61	2008	27	0.0039
61	2008	28	0.0030
61	2008	29	0.0027
61	2008	30	0.0343
62	2008	0	0.0078
62	2008	1	0.0232
62	2008	2	0.0307
62	2008	3	0.0907
62	2008	4	0.0721

62	2008	5	0.0808
62	2008	6	0.0564
62	2008	7	0.0520
62	2008	8	0.0360
62	2008	9	0.0552
62	2008	10	0.1019
62	2008	11	0.0813
62	2008	12	0.0603
62	2008	13	0.0425
62	2008	14	0.0439
62	2008	15	0.0442
62	2008	16	0.0273
62	2008	17	0.0202
62	2008	18	0.0122
62	2008	19	0.0101
62	2008	20	0.0103
62	2008	21	0.0080
62	2008	22	0.0079
62	2008	23	0.0058
62	2008	24	0.0050
62	2008	25	0.0036
62	2008	26	0.0038
62	2008	27	0.0001
62	2008	28	0.0012
62	2008	29	0.0010
62	2008	30	0.0046

Table 6 : Kentucky Custom Domain Age distribution

Source TypeID	yearID	ageID	ageFraction
11	2008	0	0.0020
11	2008	1	0.0323
11	2008	2	0.0606
11	2008	3	0.0826
11	2008	4	0.0831
11	2008	5	0.0774
11	2008	6	0.0667
11	2008	7	0.0830
11	2008	8	0.0650
11	2008	9	0.0495
11	2008	10	0.0424
11	2008	11	0.0345
11	2008	12	0.0287
11	2008	13	0.0214
11	2008	14	0.0240
11	2008	15	0.0208
11	2008	16	0.0138
11	2008	17	0.0129
11	2008	18	0.0092
11	2008	19	0.0051
11	2008	20	0.0052
11	2008	21	0.0058
11	2008	22	0.0078
11	2008	23	0.0108
11	2008	24	0.0153
11	2008	25	0.0168
11	2008	26	0.0124
11	2008	27	0.0160
11	2008	28	0.0228
11	2008	29	0.0152
11	2008	30	0.0568
21	2008	0	0.0118
21	2008	1	0.0665
21	2008	2	0.0596
21	2008	3	0.0642
21	2008	4	0.0611
21	2008	5	0.0705
21	2008	6	0.0694
21	2008	7	0.0699
21	2008	8	0.0719
21	2008	9	0.0619
21	2008	10	0.0633
21	2008	11	0.0591
21	2008	12	0.0490
21	2008	13	0.0442
21	2008	14	0.0348
21	2008	15	0.0318
21	2008	16	0.0241
21	2008	17	0.0191
21	2008	18	0.0142
21	2008	19	0.0111
21	2008	20	0.0088
21	2008	21	0.0066
21	2008	22	0.0049
21	2008	23	0.0039
21	2008	24	0.0028
21	2008	25	0.0024

21	2008	26	0.0018
21	2008	27	0.0009
21	2008	28	0.0005
21	2008	29	0.0005
21	2008	30	0.0094
31	2008	0	0.0000
31	2008	1	0.0000
31	2008	2	0.0000
31	2008	3	0.0000
31	2008	4	0.0238
31	2008	5	0.0119
31	2008	6	0.0119
31	2008	7	0.0119
31	2008	8	0.0119
31	2008	9	0.0000
31	2008	10	0.0238
31	2008	11	0.0357
31	2008	12	0.0119
31	2008	13	0.0952
31	2008	14	0.0833
31	2008	15	0.0595
31	2008	16	0.1071
31	2008	17	0.0357
31	2008	18	0.0357
31	2008	19	0.0357
31	2008	20	0.0119
31	2008	21	0.0476
31	2008	22	0.0238
31	2008	23	0.0119
31	2008	24	0.0119
31	2008	25	0.0595
31	2008	26	0.0357
31	2008	27	0.0000
31	2008	28	0.0238
31	2008	29	0.0238
31	2008	30	0.1548
32	2008	0	0.0000
32	2008	1	0.0000
32	2008	2	0.0000
32	2008	3	0.0000
32	2008	4	0.0238
32	2008	5	0.0119
32	2008	6	0.0119
32	2008	7	0.0119
32	2008	8	0.0119
32	2008	9	0.0000
32	2008	10	0.0238
32	2008	11	0.0357
32	2008	12	0.0119
32	2008	13	0.0952
32	2008	14	0.0833
32	2008	15	0.0595
32	2008	16	0.1071
32	2008	17	0.0357
32	2008	18	0.0357
32	2008	19	0.0357
32	2008	20	0.0119
32	2008	21	0.0476
32	2008	22	0.0238
32	2008	23	0.0119
32	2008	24	0.0119
32	2008	25	0.0595
32	2008	26	0.0357
32	2008	27	0.0000
32	2008	28	0.0238
32	2008	29	0.0238
32	2008	30	0.1548
41	2008	0	0.0455
41	2008	1	0.1136
41	2008	2	0.0000
41	2008	3	0.0114
41	2008	4	0.0227
41	2008	5	0.0000
41	2008	6	0.0000
41	2008	7	0.0114
41	2008	8	0.0114
41	2008	9	0.0227
41	2008	10	0.0114
41	2008	11	0.0568
41	2008	12	0.1250
41	2008	13	0.0227
41	2008	14	0.0000
41	2008	15	0.0341
41	2008	16	0.0341
41	2008	17	0.0682
41	2008	18	0.0455
41	2008	19	0.0909
41	2008	20	0.0568
41	2008	21	0.0455
41	2008	22	0.0341
41	2008	23	0.0455
41	2008	24	0.0227
41	2008	25	0.0227
41	2008	26	0.0114
41	2008	27	0.0000
41	2008	28	0.0227
41	2008	29	0.0000
41	2008	30	0.0114

42	2008	0	0.0455
42	2008	1	0.1136
42	2008	2	0.0000
42	2008	3	0.0114
42	2008	4	0.0227
42	2008	5	0.0000
42	2008	6	0.0000
42	2008	7	0.0114
42	2008	8	0.0114
42	2008	9	0.0227
42	2008	10	0.0114
42	2008	11	0.0568
42	2008	12	0.1250
42	2008	13	0.0227
42	2008	14	0.0000
42	2008	15	0.0341
42	2008	16	0.0341
42	2008	17	0.0682
42	2008	18	0.0455
42	2008	19	0.0909
42	2008	20	0.0568
42	2008	21	0.0455
42	2008	22	0.0341
42	2008	23	0.0455
42	2008	24	0.0227
42	2008	25	0.0227
42	2008	26	0.0114
42	2008	27	0.0000
42	2008	28	0.0227
42	2008	29	0.0000
42	2008	30	0.0114
43	2008	0	0.0455
43	2008	1	0.1136
43	2008	2	0.0000
43	2008	3	0.0114
43	2008	4	0.0227
43	2008	5	0.0000
43	2008	6	0.0000
43	2008	7	0.0114
43	2008	8	0.0114
43	2008	9	0.0227
43	2008	10	0.0114
43	2008	11	0.0568
43	2008	12	0.1250
43	2008	13	0.0227
43	2008	14	0.0000
43	2008	15	0.0341
43	2008	16	0.0341
43	2008	17	0.0682
43	2008	18	0.0455
43	2008	19	0.0909
43	2008	20	0.0568
43	2008	21	0.0455
43	2008	22	0.0341
43	2008	23	0.0455
43	2008	24	0.0227
43	2008	25	0.0227
43	2008	26	0.0114
43	2008	27	0.0000
43	2008	28	0.0227
43	2008	29	0.0000
43	2008	30	0.0114
51	2008	0	0.0025
51	2008	1	0.0200
51	2008	2	0.0386
51	2008	3	0.0436
51	2008	4	0.0495
51	2008	5	0.0579
51	2008	6	0.0667
51	2008	7	0.0698
51	2008	8	0.0620
51	2008	9	0.0611
51	2008	10	0.0675
51	2008	11	0.0619
51	2008	12	0.0508
51	2008	13	0.0529
51	2008	14	0.0397
51	2008	15	0.0397
51	2008	16	0.0375
51	2008	17	0.0276
51	2008	18	0.0204
51	2008	19	0.0184
51	2008	20	0.0158
51	2008	21	0.0174
51	2008	22	0.0152
51	2008	23	0.0108
51	2008	24	0.0108
51	2008	25	0.0071
51	2008	26	0.0052
51	2008	27	0.0031
51	2008	28	0.0021
51	2008	29	0.0021
51	2008	30	0.0220
52	2008	0	0.0025
52	2008	1	0.0200
52	2008	2	0.0386
52	2008	3	0.0436
52	2008	4	0.0495

52	2008	5	0.0579
52	2008	6	0.0667
52	2008	7	0.0698
52	2008	8	0.0620
52	2008	9	0.0611
52	2008	10	0.0675
52	2008	11	0.0619
52	2008	12	0.0508
52	2008	13	0.0529
52	2008	14	0.0397
52	2008	15	0.0397
52	2008	16	0.0375
52	2008	17	0.0276
52	2008	18	0.0204
52	2008	19	0.0184
52	2008	20	0.0158
52	2008	21	0.0174
52	2008	22	0.0152
52	2008	23	0.0108
52	2008	24	0.0108
52	2008	25	0.0071
52	2008	26	0.0052
52	2008	27	0.0031
52	2008	28	0.0021
52	2008	29	0.0021
52	2008	30	0.0220
53	2008	0	0.0025
53	2008	1	0.0200
53	2008	2	0.0386
53	2008	3	0.0436
53	2008	4	0.0495
53	2008	5	0.0579
53	2008	6	0.0667
53	2008	7	0.0698
53	2008	8	0.0620
53	2008	9	0.0611
53	2008	10	0.0675
53	2008	11	0.0619
53	2008	12	0.0508
53	2008	13	0.0529
53	2008	14	0.0397
53	2008	15	0.0397
53	2008	16	0.0375
53	2008	17	0.0276
53	2008	18	0.0204
53	2008	19	0.0184
53	2008	20	0.0158
53	2008	21	0.0174
53	2008	22	0.0152
53	2008	23	0.0108
53	2008	24	0.0108
53	2008	25	0.0071
53	2008	26	0.0052
53	2008	27	0.0031
53	2008	28	0.0021
53	2008	29	0.0021
53	2008	30	0.0220
54	2008	0	0.0025
54	2008	1	0.0200
54	2008	2	0.0386
54	2008	3	0.0436
54	2008	4	0.0495
54	2008	5	0.0579
54	2008	6	0.0667
54	2008	7	0.0698
54	2008	8	0.0620
54	2008	9	0.0611
54	2008	10	0.0675
54	2008	11	0.0619
54	2008	12	0.0508
54	2008	13	0.0529
54	2008	14	0.0397
54	2008	15	0.0397
54	2008	16	0.0375
54	2008	17	0.0276
54	2008	18	0.0204
54	2008	19	0.0184
54	2008	20	0.0158
54	2008	21	0.0174
54	2008	22	0.0152
54	2008	23	0.0108
54	2008	24	0.0108
54	2008	25	0.0071
54	2008	26	0.0052
54	2008	27	0.0031
54	2008	28	0.0021
54	2008	29	0.0021
54	2008	30	0.0220
61	2008	0	0.0000
61	2008	1	0.0064
61	2008	2	0.0295
61	2008	3	0.0205
61	2008	4	0.0321
61	2008	5	0.0346
61	2008	6	0.0423
61	2008	7	0.0308
61	2008	8	0.0269
61	2008	9	0.0179

61	2008	10	0.0462
61	2008	11	0.0410
61	2008	12	0.0359
61	2008	13	0.0513
61	2008	14	0.0333
61	2008	15	0.0359
61	2008	16	0.0423
61	2008	17	0.0269
61	2008	18	0.0295
61	2008	19	0.0231
61	2008	20	0.0385
61	2008	21	0.0397
61	2008	22	0.0333
61	2008	23	0.0346
61	2008	24	0.0295
61	2008	25	0.0192
61	2008	26	0.0346
61	2008	27	0.0128
61	2008	28	0.0141
61	2008	29	0.0128
61	2008	30	0.1244
62	2008	0	0.0000
62	2008	1	0.0064
62	2008	2	0.0295
62	2008	3	0.0205
62	2008	4	0.0321
62	2008	5	0.0346
62	2008	6	0.0423
62	2008	7	0.0308
62	2008	8	0.0269
62	2008	9	0.0179
62	2008	10	0.0462
62	2008	11	0.0410
62	2008	12	0.0359
62	2008	13	0.0513
62	2008	14	0.0333
62	2008	15	0.0359
62	2008	16	0.0423
62	2008	17	0.0269
62	2008	18	0.0295
62	2008	19	0.0231
62	2008	20	0.0385
62	2008	21	0.0397
62	2008	22	0.0333
62	2008	23	0.0346
62	2008	24	0.0295
62	2008	25	0.0192
62	2008	26	0.0346
62	2008	27	0.0128
62	2008	28	0.0141
62	2008	29	0.0128
62	2008	30	0.1244

2.4 Vehicle Type VMT and VMT Fractions

This option is useful to import the annual VMT by source type into MOVES format. It has input option as HPMS Base Year VMT, for which we can either use HPMS data or the Travel Demand Model output. We have used annual VMT calculated from the OKI Regional Travel Demand Model. There are options like the Month VMT fraction, Day VMT fraction and Hour VMT fraction, which are useful for calculating emissions for different time periods. We have used default Monthly VMT distribution factors provided in the VMT Converter provided by EPA. Hourly distribution factors are developed from traffic count data collected in the region and the same set of Hourly Distribution Factors are used for all vehicle types and road types. OKI model could only predict VMT of two different vehicle types' autos and trucks. So, we have distributed total Annual VMT based on vehicle population in the region.

Table 7 : Annual VMT for Ohio Custom Domain from OKI travel demand model for 2005

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2005	67065022	0
20	2005	7405961237	0
30	2005	4943917030	0
40	2005	24512225	0
50	2005	334351024	0
60	2005	567810955	0

Table 8 :Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2005

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2005	16658465	0
20	2005	1815341688	0
30	2005	1209494070	0
40	2005	5968488	0
50	2005	82065068	0
60	2005	160708291	0

Table 9: Annual VMT for Ohio Custom Domain from OKI travel demand model for 2008

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	69438850	0
20	2008	7668102136	0
30	2008	5118911580	0
40	2008	25379858	0
50	2008	346185690	0
60	2008	587909153	0

Table 10 : Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2008

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	17342291	0
20	2008	1889861055	0
30	2008	1259143528	0
40	2008	6213493	0
50	2008	85433821	0
60	2008	167305330	0

Table 9: Annual VMT for Ohio Custom Domain from OKI travel demand model for 2011

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	69438850	0
20	2008	7668102136	0
30	2008	5118911580	0
40	2008	25379858	0
50	2008	346185689	0
60	2008	587909153	0

Table 11: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2011

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2011	18163152	0
20	2011	1979313603	0
30	2011	1318742406	0
40	2011	6507596	0
50	2011	89477649	0
60	2011	175224371	0

Table 12 :Annual VMT for Ohio Custom Domain from OKI travel demand model for 2015

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2015	73413634	0
20	2015	8107035747	0
30	2015	5411925719	0
40	2015	26832639	0
50	2015	366001875	0
60	2015	621561950	0

Table 13: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2015

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2015	19903870	0
20	2015	2169006811	0
30	2015	1445127874	0

40	2015	7131270	0
50	2015	98052996	0
60	2015	192017502	0

Table 14:Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2018

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2018	76802311	0
20	2018	8481245879	0
30	2018	5661733109	0
40	2018	28071199	0
50	2018	382896041	0
60	2018	650252434	0

Table 13:Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2018

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2018	21077884	0
20	2018	2296944011	0
30	2018	1530367631	0
40	2018	7551902	0
50	2018	103836577	0
60	2018	203343507	0

Table 14 : Annual VMT for Ohio Custom Domain from OKI travel demand model for 2021

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2021	79128218	0
20	2021	8738094842	0
30	2021	5833194979	0
40	2021	28921317	0
50	2021	394491797	0
60	2021	669944902	0

Table 15 : Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2021

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2021	21702396	0
20	2021	2364999583	0
30	2021	1575710506	0
40	2021	7775656	0
50	2021	106913124	0
60	2021	209368320	0

Table 16 : Default Monthly VMT Distribution(year 2008)

sourceTypeID	isLeapYear	monthID	monthVMTFraction
11	Y	1	0.072904
11	Y	2	0.072023
11	Y	3	0.081529
11	Y	4	0.082098
11	Y	5	0.087286
11	Y	6	0.088052
11	Y	7	0.092096
11	Y	8	0.093198
11	Y	9	0.08447
11	Y	10	0.086301
11	Y	11	0.080029
11	Y	12	0.080015
21	Y	1	0.072904
21	Y	2	0.072023
21	Y	3	0.081529
21	Y	4	0.082098
21	Y	5	0.087286
21	Y	6	0.088052
21	Y	7	0.092096
21	Y	8	0.093198
21	Y	9	0.08447
21	Y	10	0.086301
21	Y	11	0.080029
21	Y	12	0.080015
31	Y	1	0.072904
31	Y	2	0.072023

Table 17 : Default Daily VMT distribution (same for all Source Types and all years)

sourceTypeID	monthID	roadTypeID	dayID	dayVMTFraction
11	1	1	2	0.237635
11	1	1	5	0.762365
11	1	2	2	0.237635
11	1	2	5	0.762365
11	1	3	2	0.237635
11	1	3	5	0.762365
11	1	4	2	0.237635
11	1	4	5	0.762365
11	1	5	2	0.237635
11	1	5	5	0.762365

Table 18 : Hourly VMT Distribution from local data

sourceTypeID	roadTypeID	dayID	hourID	hourVMTFraction
11	1	2	1	0.021474
11	1	2	2	0.014443
11	1	2	3	0.010968
11	1	2	4	0.007495
11	1	2	5	0.006839
11	1	2	6	0.010359
11	1	2	7	0.01843
11	1	2	8	0.026812
11	1	2	9	0.036385
11	1	2	10	0.047541
11	1	2	11	0.057466
11	1	2	12	0.065079
11	1	2	13	0.071323
11	1	2	14	0.071492
11	1	2	15	0.071723
11	1	2	16	0.072006
11	1	2	17	0.071149
11	1	2	18	0.067887
11	1	2	19	0.061772
11	1	2	20	0.051688
11	1	2	21	0.042866
11	1	2	22	0.03803
11	1	2	23	0.032207
11	1	2	24	0.024568

2.5 Average Speed Distribution Importer

This importer allows the user to input average speed data specific to vehicle type, road type, and time of day/ type of day. The MOVES model defines 16 “speed bins” which describe the average driving speed on each road type. Unlike MOBILE 6.2 model, which uses VMT-based speed distribution, MOVES use fraction of driving time in each speed bin for each vehicle type, for each road type, and for each hour. Thus, for each combination of vehicle type, road type, and hour/day type, the fractions will add to one. We have used OKI travel model to calculate average speed distribution based on VHT. However, this input is ignored by MOVES when we are running emission rate runs† (See Table 27).

2.6 Road Type Distribution Importer

User supplied vehicle-miles-traveled data by road type is used as an input in this importer. OKI travel demand model can calculate the VMT distribution by functional class, which is further

processed to obtain road type VMT distribution. But, our model could not predict off network VMT, which is assumed as zero. However, this input is also ignored by MOVES when we are running Emission Rate runs † (see Table 26).

2.7 Ramp Fraction Importer

This option allows the user to modify the fraction of ramp driving time on selected road types. But, in the current version of MOVES model, there is no capability to model Emission Rates for Ramps. To circumvent this problem, FHWA has suggested a temporary solution. This solution discussed in the Section 3.

2.8 Fuel Formulation Importer and Fuel Supply Importer

Fuel formulation importer allows the user to select an existing fuel in the MOVES database and change its properties, or create a new fuel formulation with different fuel properties. But we have used only default fuels available in MOVES default database. Fuel supply importer allows the user to assign existing fuels to counties, months, and years, and the associated market share for each fuel. We have used default fuel supply from MOVES default database. And same type of fuel is used for Whole Custom Domain.

Table 19 : Fuel supply data for Ohio Custom Domain (same for all years)

countyID	fuelYearID	monthGroupID	fuelFormulationID	marketShare	marketShareCV
99390	2008	1	3982	1	
99390	2008	1	20011	1	
99390	2008	2	3982	1	
99390	2008	2	20011	1	
99390	2008	3	3982	1	
99390	2008	3	20011	1	
99390	2008	4	3982	1	
99390	2008	4	20011	1	
99390	2008	5	3982	1	
99390	2008	5	20011	1	
99390	2008	6	3982	1	
99390	2008	6	20011	1	
99390	2008	7	3982	1	
99390	2008	7	20011	1	
99390	2008	8	3982	1	
99390	2008	8	20011	1	
99390	2008	9	3982	1	
99390	2008	9	20011	1	
99390	2008	10	3982	1	
99390	2008	10	20011	1	
99390	2008	11	3982	1	
99390	2008	11	20011	1	

99390	2008	12	3982	1	
99390	2008	12	20011	1	

Table 20: Fuel supply data for Kentucky Custom Domain (same for all years)

countyID	fuelYearID	monthGroupID	fuelFormulationID	marketShare	marketShareCV
99210	2012	1	3982	1	
99210	2012	1	20011	1	
99210	2012	2	3982	1	
99210	2012	2	20011	1	
99210	2012	3	3982	1	
99210	2012	3	20011	1	
99210	2012	4	3982	1	
99210	2012	4	20011	1	
99210	2012	5	3982	1	
99210	2012	5	20011	1	
99210	2012	6	3982	1	
99210	2012	6	20011	1	
99210	2012	7	3982	1	
99210	2012	7	20011	1	
99210	2012	8	3982	1	
99210	2012	8	20011	1	
99210	2012	9	3982	1	
99210	2012	9	20011	1	
99210	2012	10	3982	1	
99210	2012	10	20011	1	
99210	2012	11	3982	1	
99210	2012	11	20011	1	
99210	2012	12	3982	1	
99210	2012	12	20011	1	

2.9 I/M Importer

The I/M Importer allows the user to import information describing the inspection and maintenance programs. In the default database there is an option, whether to use default I/M program or not. We choose no I/M program for all of the Runspecs[sic] in the whole region.

2.10 Zone Road Activity Importer

The Zone Road Activity Importer is used only if the Custom Domain option is chosen in the County Domain Manager. We have used value 1 for SHOallocfactor for each road type which means that all of the VMT input by the users is assigned to custom domain.

Table 21 : Kentucky Custom Domain Zone road activity data (same for all years)

zoneID	roadTypeID	SHOAllocFactor
992100	1	1
992100	2	1
992100	3	1
992100	4	1
992100	5	1

Table 22 : Ohio Custom Domain Zone road activity data (same for all years)

zoneID	roadTypeID	SHOAllocFactor
993900	1	1
993900	2	1
993900	3	1
993900	4	1
993900	5	1

3. Ramp Inventory Runs

As discussed earlier, current version of the MOVES model cannot calculate Emission Rates for Ramps. To deal with this problem, FHWA has suggested an approach. The steps involved in this method are: (a) Calculating Emission Inventory for Urban Restricted and Rural Restricted road types keeping Ramp fraction as 1 (b) Finding out total VMT of Urban Restricted and Rural Restricted road types using MOVESactivityoutput option (c) Calculation Emission Rates for Ramps through dividing Emission Inventory with VMT (d) Finally, using the Emission Rates in post processing for calculating regional Emission Inventory.

Table 23 :Ramp fraction Input

roadTypeID	rampFraction
2	1
4	1

4. Post-Processing of MOVES Output

4.1 Linking SQL tables to Microsoft Access

Microsoft Access 2007 was used for the post-processing. An ODBC connection with the MOVES output directory was established. Information on how to link or import SQL tables to Access can be found in the MOVES Users Guide.

4.2 Creating Emission Rate Lookup Tables

The ratepervehicle and rateperdistance SQL tables, one set for each state (Kentucky and Ohio) and analysis year, were imported into Access. Ohio emission rates are used for the nonattainment portion of Dearborn County Indiana. Rateperprofile output was not generated by MOVES because evaporative output was not selected (i.e. VOC). Tables were renamed with state and analysis year in the format OH_20xxrateperdistance. All rateperdistance tables were merged with a Union query. The SQL commands are shown in Figure 3.1. ratepervehicle tables were merged in the same manner.

Table 24 :Rateperdistance Union Query

```
SELECT *
FROM OH_2008rateperdistance
WHERE MOVESRunID = (select max (MOVESRunID) from OH_2008rateperdistance) AND
pollutantID = 3 Or MOVESRunID =  (select max (MOVESRunID) from
OH_2008rateperdistance) AND pollutantID=110 Or MOVESRunID =  (select max
(MOVESRunID) from OH_2008rateperdistance) AND pollutantID=116 Or MOVESRunID =
(select max (MOVESRunID) from OH_2008rateperdistance) AND pollutantID=117 Or
MOVESRunID = (select max (MOVESRunID) from OH_2008rateperdistance) AND
pollutantID = 31
UNION ALL select *
FROM OH_2011rateperdistance
WHERE ….. (repeated for each file)
```

"Rateperdistance_state" and "Ratepervehicle_state" tables were created from the union query output using a Make Table query. Emission rates for each process were summed by pollutant and a stateID field is created. The SQL commands for creating the "Rateperdistance_state" table are shown in Table 25. Unique index fields were identified for each of the two tables. Indexes facilitate more efficient data processing.

Table 25: Rateperdistance_State Query

```
SELECT Val(Mid([LinkID],3,2)) AS StateID, Union_rateperdistance_state.yearID,
Union_rateperdistance_state.monthID, Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.sourceTypeID,
Union_rateperdistance_state.roadTypeID,
Union_rateperdistance_state.avgSpeedBinID,
Union_rateperdistance_state.pollutantID,
Sum(Union_rateperdistance_state.ratePerDistance) AS SumOfratePerDistance INTO
rateperdistance_state
```

```
FROM Union_rateperdistance_state
GROUP BY Val(Mid([LinkID],3,2)), Union_rateperdistance_state.yearID,
Union_rateperdistance_state.monthID, Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.sourceTypeID,
Union_rateperdistance_state.roadTypeID,
Union_rateperdistance_state.avgSpeedBinID,
Union_rateperdistance_state.pollutantID
ORDER BY Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.pollutantID;
```

4.1 Creating a VMT Table by County

The VMT table includes Daily VMT by county by analysis year from the OKI Travel Demand Model (TDM). Summer factors and applied by functional class to create Summer VMT. Seasonal factors by functional class are contained in the report, "OKI Travel Demand Forecasting Model, Update of Hourly and Seasonal Factors as Used in Air Quality Impact Calculations", September 2001. Annual VMT is calculated by using EPA's VMT converter to grow daily VMT to annual VMT. In order to accommodate an error in MOVES 2010, all VMT values are exclusive of ramp VMT. Ramp VMT and emission are added in later in the process. In order to apply the emission rates, it is necessary to factor the county VMT by source type, hour, road type and speed bin.

Table 26 : VMT and Source Type Population by County and Year

County	Daily VMT	Summer VMT	Annual VMT	yearID	SourceType Population	stateID
Boone	3924117	4186006	1273226984	2005	129823	21
Boone	4076584	4355527	1350001557	2008	134028	21
Boone	4383716	4681593	1448879510	2011	136181	21
Boone	4950741	5276742	1628041303	2015	140590	21
Boone	5260102	5597287	1729595179	2018	143991	21
Boone	5478224	5826768	1800571708	2021	147476	21
Campbell	2286217	2437698	741790605	2005	86065	21
Campbell	2339542	2495174	774762729	2008	88853	21
Campbell	2421600	2582758	800372702	2011	90279	21
Campbell	2663159	2844504	875774499	2015	93204	21
Campbell	2771476	2958827	911300109	2018	95458	21
Campbell	2849127	3041704	936445364	2021	97768	21
Kenton	3927743	4182042	1274091658	2005	148193	21
Kenton	3927332	4185652	1300575265	2008	152992	21
Kenton	4049886	4327836	1338544021	2011	155451	21
Kenton	4341124	4614242	1427569992	2015	160484	21
Kenton	4629694	4880614	1522308203	2018	164368	21
Kenton	4715306	5006383	1549817345	2021	168343	21
Butler	578641	7804476	196737836	2005	24915	39

Butler	587582	8133554	199777880	2008	25722	39
Butler	605620	8454053	205910800	2011	26135	39
Butler	657778	8768598	223644400	2015	26982	39
Butler	684361	9232457	232682740	2018	27635	39
Butler	706828	9592567	240321520	2021	28303	39
Clermont	7452286	5391578	2469166037	2005	401759	39
Clermont	7745685	5599530	2598059212	2008	414771	39
Clermont	8050701	5841102	2693716250	2011	421434	39
Clermont	8361487	6035155	2792188144	2015	435082	39
Clermont	8806042	6314640	2940849935	2018	445608	39
Clermont	9150031	6562428	2966037449	2021	456389	39
Dearborn NA	5083331	599761	1684259908	2005	232380	39
Dearborn NA	5262489	613027	1765145113	2008	239906	39
Dearborn NA	5489545	631914	1836768820	2011	243760	39
Dearborn NA	5687698	685272	1899318043	2015	251654	39
Dearborn NA	5952603	712461	1987920583	2018	257742	39
Dearborn NA	6186441	735862	2005371969	2021	263978	39
Hamilton	21859452	23170766	7241529618	2005	862422	39
Hamilton	22124503	23447460	7421005221	2008	890352	39
Hamilton	22426021	23803187	7503612070	2011	904655	39
Hamilton	22849494	24259554	7630232069	2015	933953	39
Hamilton	23630554	25096560	7891617279	2018	956548	39
Hamilton	24098698	25596996	7811737549	2021	979689	39
Warren	5884216	6263010	1949617151	2005	233106	39
Warren	6057338	6464217	2031753523	2008	240655	39
Warren	6406284	6835660	2143504189	2011	244521	39
Warren	6842828	7279441	2285055662	2015	252440	39
Warren	7368035	7836746	2460615706	2018	258547	39
Warren	7707500	8194596	2498432370	2021	264802	39

4.2 Source type population and source type VMT distribution

A combination of local and MOVES default data were used for the source type populations. The source type VMT fractions are based on the ratio of MOVES default source type population and MOVES default source type VMT. It is assumed that the growth rate of source type populations is equal to the regional annual household growth rate of 0.8%. Source type VMT fractions are the same for all analysis years.

Table 27: Base Year Source Type Population and VMT Fraction

stateID	sourceTypeID	sourceTypePopulation	sourceTypeFraction	sourceTypeVMTFraction
39	11	69121	0.038559	0.005026
39	21	1200827	0.669872	0.555019
39	31	486373	0.271319	0.277725
39	32	15947	0.008896	0.092783
39	41	458	0.000255	0.000754
39	42	82	0.000046	0.000225
39	43	3681	0.002053	0.000858
39	51	0	0.000000	0.000644
39	52	369	0.000206	0.020527
39	53	364	0.000203	0.002663
39	54	4928	0.002749	0.001224
39	61	4879	0.002722	0.017977
39	62	5593	0.003120	0.024576
21	11	8040	0.021370	0.005063
21	21	198623	0.527931	0.551736
21	31	121506	0.322958	0.275546
21	32	40593	0.107894	0.092055
21	41	128	0.000340	0.000745
21	42	21	0.000056	0.000222
21	43	985	0.002618	0.000847
21	51	0	0.000000	0.000641
21	52	767	0.002039	0.020433
21	53	757	0.002012	0.002650
21	54	1390	0.003695	0.001218
21	61	1593	0.004234	0.020634
21	62	1826	0.004853	0.028210

4.3 Hourly distribution

MOVES default hourly distribution by source type was used during the post-processing.

4.4 Road type distribution

Road type VMT fractions by source type are default values, except for passenger cars (source type 21) and passenger trucks (source type 31). VMT fractions from the OKI TDM are used for passenger cars and passenger trucks.

Table 28: Base Year Source Type Population and VMT Fraction

sourceTypeID	roadTypeID	roadTypeVMTFraction	stateID
21	1	0	21
21	2	0.0952	21
21	3	0.0818	21
21	4	0.4741	21
21	5	0.3489	21
31	1	0	21
31	2	0.0952	21
31	3	0.0818	21
31	4	0.4741	21
31	5	0.3489	21
21	1	0	39
21	2	0.0436	39
21	3	0.1256	39
21	4	0.4143	39
21	5	0.4165	39
31	1	0	39
31	2	0.0436	39
31	3	0.1256	39
31	4	0.4143	39
31	5	0.4165	39

4.5 Average speed distribution

Average speed fractions for each of the 16 speed bins are provided by the OKI TDM. The average speed fractions vary by state, year, road type and hour.

Table 29: Average Speed Distribution (Example: only road type 2, year 2011, Ohio values shown)

roadTypeID	hourID	avgSpeedBinID	avgSpeedFraction	YearID	stateID
2	1	1	0.00000000	2011	39
2	1	2	0.00000000	2011	39
2	1	3	0.00000000	2011	39
2	1	4	0.00000000	2011	39
2	1	5	0.00000000	2011	39
2	1	6	0.00000000	2011	39
2	1	7	0.00000000	2011	39
2	1	8	0.00000000	2011	39

2	1	9	0.00000000	2011	39
2	1	10	0.11922233	2011	39
2	1	11	0.12547629	2011	39
2	1	12	0.19752816	2011	39
2	1	13	0.00589550	2011	39
2	1	14	0.00000000	2011	39
2	1	15	0.55187773	2011	39
2	1	16	0.00000000	2011	39
2	2	1	0.00000000	2011	39
2	2	2	0.00000000	2011	39
2	2	3	0.00000000	2011	39
2	2	4	0.00000000	2011	39
2	2	5	0.00000000	2011	39
2	2	6	0.00000000	2011	39
2	2	7	0.00000000	2011	39
2	2	8	0.00000000	2011	39
2	2	9	0.00000000	2011	39
2	2	10	0.11922233	2011	39
2	2	11	0.12547629	2011	39
2	2	12	0.19752816	2011	39
2	2	13	0.00589550	2011	39
2	2	14	0.00000000	2011	39
2	2	15	0.55187773	2011	39
2	2	16	0.00000000	2011	39
2	3	1	0.00000000	2011	39
2	3	2	0.00000000	2011	39
2	3	3	0.00000000	2011	39
2	3	4	0.00000000	2011	39
2	3	5	0.00000000	2011	39
2	3	6	0.00000000	2011	39
2	3	7	0.00000000	2011	39
2	3	8	0.00000000	2011	39
2	3	9	0.00000000	2011	39
2	3	10	0.11922233	2011	39
2	3	11	0.12547629	2011	39
2	3	12	0.19752816	2011	39
2	3	13	0.00589550	2011	39
2	3	14	0.06436270	2011	39

2	3	15	0.48751503	2011	39
2	3	16	0.00000000	2011	39
2	4	1	0.00000000	2011	39
2	4	2	0.00000000	2011	39
2	4	3	0.00000000	2011	39
2	4	4	0.00000000	2011	39
2	4	5	0.00000000	2011	39
2	4	6	0.00000000	2011	39
2	4	7	0.00000000	2011	39
2	4	8	0.00000000	2011	39
2	4	9	0.00000000	2011	39
2	4	10	0.11922233	2011	39
2	4	11	0.12547629	2011	39
2	4	12	0.19752816	2011	39
2	4	13	0.00589550	2011	39
2	4	14	0.12369152	2011	39
2	4	15	0.42818621	2011	39
2	4	16	0.00000000	2011	39
2	5	1	0.00000000	2011	39
2	5	2	0.00000000	2011	39
2	5	3	0.00000000	2011	39
2	5	4	0.00000000	2011	39
2	5	5	0.00000000	2011	39
2	5	6	0.00000000	2011	39
2	5	7	0.00000000	2011	39
2	5	8	0.00000000	2011	39
2	5	9	0.00000000	2011	39
2	5	10	0.11922233	2011	39
2	5	11	0.12547629	2011	39
2	5	12	0.26189086	2011	39
2	5	13	0.09782827	2011	39
2	5	14	0.06250896	2011	39
2	5	15	0.33307330	2011	39
2	5	16	0.00000000	2011	39
2	6	1	0.00000000	2011	39
2	6	2	0.12369152	2011	39
2	6	3	0.03260396	2011	39
2	6	4	0.03085494	2011	39

2	6	5	0.01601927	2011	39
2	6	6	0.01563475	2011	39
2	6	7	0.00000000	2011	39
2	6	8	0.00000000	2011	39
2	6	9	0.00000000	2011	39
2	6	10	0.11922233	2011	39
2	6	11	0.12547629	2011	39
2	6	12	0.19752816	2011	39
2	6	13	0.00589550	2011	39
2	6	14	0.00278921	2011	39
2	6	15	0.33028409	2011	39
2	6	16	0.00000000	2011	39
2	7	1	0.21880443	2011	39
2	7	2	0.00000000	2011	39
2	7	3	0.00278921	2011	39
2	7	4	0.00000000	2011	39
2	7	5	0.01131028	2011	39
2	7	6	0.03548550	2011	39
2	7	7	0.03519436	2011	39
2	7	8	0.03514937	2011	39
2	7	9	0.00617093	2011	39
2	7	10	0.08564905	2011	39
2	7	11	0.14691446	2011	39
2	7	12	0.13064235	2011	39
2	7	13	0.00589550	2011	39
2	7	14	0.14352342	2011	39
2	7	15	0.14247115	2011	39
2	7	16	0.00000000	2011	39
2	8	1	0.21880443	2011	39
2	8	2	0.00278921	2011	39
2	8	3	0.01131028	2011	39
2	8	4	0.01356074	2011	39
2	8	5	0.05711912	2011	39
2	8	6	0.03514937	2011	39
2	8	7	0.02902228	2011	39
2	8	8	0.01193860	2011	39
2	8	9	0.07229727	2011	39
2	8	10	0.05473480	2011	39

2	8	11	0.08493157	2011	39
2	8	12	0.11645227	2011	39
2	8	13	0.04360641	2011	39
2	8	14	0.20648097	2011	39
2	8	15	0.04180267	2011	39
2	8	16	0.00000000	2011	39
2	9	1	0.21880443	2011	39
2	9	2	0.00000000	2011	39
2	9	3	0.00000000	2011	39
2	9	4	0.00000000	2011	39
2	9	5	0.00000000	2011	39
2	9	6	0.00278921	2011	39
2	9	7	0.00000000	2011	39
2	9	8	0.04679577	2011	39
2	9	9	0.03519436	2011	39
2	9	10	0.08369185	2011	39
2	9	11	0.14590244	2011	39
2	9	12	0.15349370	2011	39
2	9	13	0.02733367	2011	39
2	9	14	0.03771092	2011	39
2	9	15	0.24828365	2011	39
2	9	16	0.00000000	2011	39
2	10	1	0.15629548	2011	39
2	10	2	0.04687421	2011	39
2	10	3	0.01563475	2011	39
2	10	4	0.00000000	2011	39
2	10	5	0.00000000	2011	39
2	10	6	0.00000000	2011	39
2	10	7	0.00000000	2011	39
2	10	8	0.00000000	2011	39
2	10	9	0.00000000	2011	39
2	10	10	0.11922233	2011	39
2	10	11	0.13957578	2011	39
2	10	12	0.18621788	2011	39
2	10	13	0.00589550	2011	39
2	10	14	0.04428952	2011	39
2	10	15	0.28599457	2011	39
2	10	16	0.00000000	2011	39

2	11	1	0.06436270	2011	39
2	11	2	0.12278771	2011	39
2	11	3	0.01601927	2011	39
2	11	4	0.01563475	2011	39
2	11	5	0.00000000	2011	39
2	11	6	0.00000000	2011	39
2	11	7	0.00000000	2011	39
2	11	8	0.00000000	2011	39
2	11	9	0.00000000	2011	39
2	11	10	0.11922233	2011	39
2	11	11	0.13678656	2011	39
2	11	12	0.18900709	2011	39
2	11	13	0.00589550	2011	39
2	11	14	0.02285135	2011	39
2	11	15	0.30743274	2011	39
2	11	16	0.00000000	2011	39
2	12	1	0.06436270	2011	39
2	12	2	0.09193278	2011	39
2	12	3	0.04687421	2011	39
2	12	4	0.01563475	2011	39
2	12	5	0.00000000	2011	39
2	12	6	0.00000000	2011	39
2	12	7	0.00000000	2011	39
2	12	8	0.00000000	2011	39
2	12	9	0.00000000	2011	39
2	12	10	0.11922233	2011	39
2	12	11	0.12547629	2011	39
2	12	12	0.20031737	2011	39
2	12	13	0.00589550	2011	39
2	12	14	0.02285135	2011	39
2	12	15	0.30743274	2011	39
2	12	16	0.00000000	2011	39
2	13	1	0.06436270	2011	39
2	13	2	0.09193278	2011	39
2	13	3	0.04687421	2011	39
2	13	4	0.01563475	2011	39
2	13	5	0.00000000	2011	39
2	13	6	0.00000000	2011	39

2	13	7	0.00000000	2011	39
2	13	8	0.00000000	2011	39
2	13	9	0.00000000	2011	39
2	13	10	0.11922233	2011	39
2	13	11	0.12547629	2011	39
2	13	12	0.19752816	2011	39
2	13	13	0.00868471	2011	39
2	13	14	0.00000000	2011	39
2	13	15	0.33028409	2011	39
2	13	16	0.00000000	2011	39
2	14	1	0.06436270	2011	39
2	14	2	0.09193278	2011	39
2	14	3	0.03085494	2011	39
2	14	4	0.03165402	2011	39
2	14	5	0.00000000	2011	39
2	14	6	0.00000000	2011	39
2	14	7	0.00000000	2011	39
2	14	8	0.00000000	2011	39
2	14	9	0.00000000	2011	39
2	14	10	0.11922233	2011	39
2	14	11	0.12547629	2011	39
2	14	12	0.19752816	2011	39
2	14	13	0.00868471	2011	39
2	14	14	0.00000000	2011	39
2	14	15	0.33028409	2011	39
2	14	16	0.00000000	2011	39
2	15	1	0.06436270	2011	39
2	15	2	0.09193278	2011	39
2	15	3	0.04687421	2011	39
2	15	4	0.01563475	2011	39
2	15	5	0.00000000	2011	39
2	15	6	0.00000000	2011	39
2	15	7	0.00000000	2011	39
2	15	8	0.00000000	2011	39
2	15	9	0.00000000	2011	39
2	15	10	0.11922233	2011	39
2	15	11	0.12547629	2011	39
2	15	12	0.19752816	2011	39

2	15	13	0.00868471	2011	39
2	15	14	0.02285135	2011	39
2	15	15	0.30743274	2011	39
2	15	16	0.00000000	2011	39
2	16	1	0.12369152	2011	39
2	16	2	0.07947816	2011	39
2	16	3	0.01563475	2011	39
2	16	4	0.00000000	2011	39
2	16	5	0.00000000	2011	39
2	16	6	0.00000000	2011	39
2	16	7	0.00000000	2011	39
2	16	8	0.00000000	2011	39
2	16	9	0.00000000	2011	39
2	16	10	0.11922233	2011	39
2	16	11	0.13957578	2011	39
2	16	12	0.18621788	2011	39
2	16	13	0.00589550	2011	39
2	16	14	0.04428952	2011	39
2	16	15	0.28599457	2011	39
2	16	16	0.00000000	2011	39
2	17	1	0.20316968	2011	39
2	17	2	0.01563475	2011	39
2	17	3	0.00000000	2011	39
2	17	4	0.00000000	2011	39
2	17	5	0.00000000	2011	39
2	17	6	0.00000000	2011	39
2	17	7	0.00278921	2011	39
2	17	8	0.02487101	2011	39
2	17	9	0.05711912	2011	39
2	17	10	0.05722137	2011	39
2	17	11	0.15811770	2011	39
2	17	12	0.14489757	2011	39
2	17	13	0.05018502	2011	39
2	17	14	0.00000000	2011	39
2	17	15	0.28599457	2011	39
2	17	16	0.00000000	2011	39
2	18	1	0.15629548	2011	39
2	18	2	0.04687421	2011	39

2	18	3	0.01563475	2011	39
2	18	4	0.00000000	2011	39
2	18	5	0.00000000	2011	39
2	18	6	0.00000000	2011	39
2	18	7	0.00000000	2011	39
2	18	8	0.00000000	2011	39
2	18	9	0.00000000	2011	39
2	18	10	0.11922233	2011	39
2	18	11	0.13957578	2011	39
2	18	12	0.18621788	2011	39
2	18	13	0.00589550	2011	39
2	18	14	0.04428952	2011	39
2	18	15	0.28599457	2011	39
2	18	16	0.00000000	2011	39
2	19	1	0.00000000	2011	39
2	19	2	0.00000000	2011	39
2	19	3	0.00000000	2011	39
2	19	4	0.00000000	2011	39
2	19	5	0.06436270	2011	39
2	19	6	0.00000000	2011	39
2	19	7	0.05932882	2011	39
2	19	8	0.03260396	2011	39
2	19	9	0.00000000	2011	39
2	19	10	0.15007727	2011	39
2	19	11	0.14149556	2011	39
2	19	12	0.21316291	2011	39
2	19	13	0.00589550	2011	39
2	19	14	0.00000000	2011	39
2	19	15	0.33307330	2011	39
2	19	16	0.00000000	2011	39
2	20	1	0.00000000	2011	39
2	20	2	0.00000000	2011	39
2	20	3	0.00000000	2011	39
2	20	4	0.00000000	2011	39
2	20	5	0.00000000	2011	39
2	20	6	0.00000000	2011	39
2	20	7	0.00000000	2011	39
2	20	8	0.00000000	2011	39

2	20	9	0.00000000	2011	39
2	20	10	0.11922233	2011	39
2	20	11	0.12547629	2011	39
2	20	12	0.19752816	2011	39
2	20	13	0.00589550	2011	39
2	20	14	0.15629548	2011	39
2	20	15	0.39558226	2011	39
2	20	16	0.00000000	2011	39
2	21	1	0.00000000	2011	39
2	21	2	0.00000000	2011	39
2	21	3	0.00000000	2011	39
2	21	4	0.00000000	2011	39
2	21	5	0.00000000	2011	39
2	21	6	0.00000000	2011	39
2	21	7	0.00000000	2011	39
2	21	8	0.00000000	2011	39
2	21	9	0.00000000	2011	39
2	21	10	0.11922233	2011	39
2	21	11	0.12547629	2011	39
2	21	12	0.19752816	2011	39
2	21	13	0.00589550	2011	39
2	21	14	0.00000000	2011	39
2	21	15	0.55187773	2011	39
2	21	16	0.00000000	2011	39
2	22	1	0.00000000	2011	39
2	22	2	0.00000000	2011	39
2	22	3	0.00000000	2011	39
2	22	4	0.00000000	2011	39
2	22	5	0.00000000	2011	39
2	22	6	0.00000000	2011	39
2	22	7	0.00000000	2011	39
2	22	8	0.00000000	2011	39
2	22	9	0.00000000	2011	39
2	22	10	0.11922233	2011	39
2	22	11	0.12547629	2011	39
2	22	12	0.19752816	2011	39
2	22	13	0.00589550	2011	39
2	22	14	0.00000000	2011	39

2	22	15	0.55187773	2011	39
2	22	16	0.00000000	2011	39
2	23	1	0.00000000	2011	39
2	23	2	0.00000000	2011	39
2	23	3	0.00000000	2011	39
2	23	4	0.00000000	2011	39
2	23	5	0.00000000	2011	39
2	23	6	0.00000000	2011	39
2	23	7	0.00000000	2011	39
2	23	8	0.00000000	2011	39
2	23	9	0.00000000	2011	39
2	23	10	0.11922233	2011	39
2	23	11	0.12547629	2011	39
2	23	12	0.19752816	2011	39
2	23	13	0.00589550	2011	39
2	23	14	0.00000000	2011	39
2	23	15	0.55187773	2011	39
2	23	16	0.00000000	2011	39
2	24	1	0.00000000	2011	39
2	24	2	0.00000000	2011	39
2	24	3	0.00000000	2011	39
2	24	4	0.00000000	2011	39
2	24	5	0.00000000	2011	39
2	24	6	0.00000000	2011	39
2	24	7	0.00000000	2011	39
2	24	8	0.00000000	2011	39
2	24	9	0.00000000	2011	39
2	24	10	0.11922233	2011	39
2	24	11	0.12547629	2011	39
2	24	12	0.19752816	2011	39
2	24	13	0.00589550	2011	39
2	24	14	0.00000000	2011	39
2	24	15	0.55187773	2011	39
2	24	16	0.00000000	2011	39

4.6 Creating a VMT Table by County, Year, Source Type, Hour, Road Type, and Average Speed Bin

The 'CountyVMT' query creates a County VMT Table by source type, hour, road type and average speed utilizing the VMT distribution factors described in 4.2, 4.3, 4.4 and 4.5. The SQL commands for this query are shown in Table 30.

Table 30 :County VMT Table Query

```
SELECT VMT.yearID, VMT.State, roadtypedistribution1.stateID, VMT.County,
roadtypedistribution1.sourceTypeID, hourvmtfraction.hourID,
roadtypedistribution1.roadTypeID, avgSpeedDistribution.avgSpeedBinID,
sourcetypepopulation.sourceTypeFraction, hourvmtfraction.hourVMTFraction,
roadtypedistribution1.roadTypeVMTFraction,
avgSpeedDistribution.avgSpeedFraction, First(VMT.[Annual VMT]) AS
[FirstOfAnnual VMT], First(VMT.[Summer VMT]) AS [FirstOfSummer VMT],
[FirstOfSummer
VMT]*[hourVMTFraction]*[sourceTypeFraction]*[roadTypeVMTFraction]*[avgSpeedFr
action] AS DailyVMT, [FirstOfAnnual
VMT]*[sourceTypeFraction]*[hourVMTFraction]*[roadTypeVMTFraction]*[avgSpeedFr
action] AS AnnualizedVMT INTO CountyVMT_Table
FROM (((avgSpeedDistribution INNER JOIN hourvmtfraction ON
(avgSpeedDistribution.hourDayID = hourvmtfraction.hourID) AND
(avgSpeedDistribution.roadTypeID = hourvmtfraction.roadTypeID) AND
(avgSpeedDistribution.sourceTypeID = hourvmtfraction.sourceTypeID)) INNER
JOIN roadtypedistribution1 ON (avgSpeedDistribution.stateID =
roadtypedistribution1.stateID) AND (avgSpeedDistribution.roadTypeID =
roadtypedistribution1.roadTypeID) AND (avgSpeedDistribution.sourceTypeID =
roadtypedistribution1.sourceTypeID)) INNER JOIN sourcetypepopulation ON
(avgSpeedDistribution.sourceTypeID = sourcetypepopulation.sourceTypeID) AND
(avgSpeedDistribution.stateID = sourcetypepopulation.stateID)) INNER JOIN
VMT ON (avgSpeedDistribution.YearID = VMT.yearID) AND
(avgSpeedDistribution.stateID = VMT.stateID)
GROUP BY VMT.yearID, VMT.State, roadtypedistribution1.stateID, VMT.County,
roadtypedistribution1.sourceTypeID, hourvmtfraction.hourID,
roadtypedistribution1.roadTypeID, avgSpeedDistribution.avgSpeedBinID,
sourcetypepopulation.sourceTypeFraction, hourvmtfraction.hourVMTFraction,
roadtypedistribution1.roadTypeVMTFraction,
avgSpeedDistribution.avgSpeedFraction
HAVING (((avgSpeedDistribution.avgSpeedFraction)>0))
ORDER BY VMT.yearID, roadtypedistribution1.stateID, VMT.County,
hourvmtfraction.hourID;
```

5. Combining VMT and Emission Rates; Calculating Total Emissions

5.1 Summarizing Distance-based Emissions by Source Type

The daily VMT and annual VMT in each county, year, hour, source type, road type, and speed bin is multiplied by the appropriate rate per distance for each pollutant. This query is shown in Table 31.

Table 31 :Emissions distance Query

```
SELECT CountyVMT_Table.stateID, CountyVMT_Table.State,
CountyVMT_Table.County, CountyVMT_Table.yearID,
rateperdistance_state.monthID, CountyVMT_Table.hourID,
rateperdistance_state.sourceTypeID, CountyVMT_Table.roadTypeID,
CountyVMT_Table.avgSpeedBinID, rateperdistance_state.pollutantID,
CountyVMT_Table.DailyVMT, CountyVMT_Table.AnnualizedVMT,
rateperdistance_state.SumOfratePerDistance, [DailyVMT]*[SumOfratePerDistance]
AS EmissionsDist, [AnnualizedVMT]*[SumOfratePerDistance] AS
AnnualEmissionsDist
FROM rateperdistance_state INNER JOIN CountyVMT_Table ON
(rateperdistance_state.avgSpeedBinID = CountyVMT_Table.avgSpeedBinID) AND
(rateperdistance_state.roadTypeID = CountyVMT_Table.roadTypeID) AND
(rateperdistance_state.sourceTypeID = CountyVMT_Table.sourceTypeID) AND
(rateperdistance_state.hourID = CountyVMT_Table.hourID) AND
(rateperdistance_state.StateID = CountyVMT_Table.stateID) AND
(rateperdistance_state.yearID = CountyVMT_Table.yearID)
GROUP BY CountyVMT_Table.stateID, CountyVMT_Table.State,
CountyVMT_Table.County, CountyVMT_Table.yearID,
rateperdistance_state.monthID, CountyVMT_Table.hourID,
rateperdistance_state.sourceTypeID, CountyVMT_Table.roadTypeID,
CountyVMT_Table.avgSpeedBinID, rateperdistance_state.pollutantID,
CountyVMT_Table.DailyVMT, CountyVMT_Table.AnnualizedVMT,
rateperdistance_state.SumOfratePerDistance;
```

A second query further summarizes the emissions by source type. This is necessary in order to combine with vehicle-based emissions that are independent of road type and speed.

5.2 Summarizing Vehicle-based Emissions by Source type

The source population for each county, year, hour, and source type is multiplied by the rate per vehicle for each pollutant. This query is shown in Table 32.

Table 32: Emissions Vehicle Query

```
SELECT VMT.stateID, VMT.County, ratepervehicle_state.yearID,
ratepervehicle_state.monthID, ratepervehicle_state.hourID,
ratepervehicle_state.sourceTypeID, sourcetypepopulation.sourceTypeFraction,
VMT.SourceTypePopulation, ratepervehicle_state.pollutantID,
ratepervehicle_state.SumOfratePerVehicle, First(VMT.BudgetAreaPop) AS
FirstOfBudgetAreaPop,
((Nz([VMT]![sourceTypePopulation]*[sourceTypeFraction],0)/24)) AS STPop,
Nz([VMT]![sourceTypePopulation]*[sourceTypeFraction]*[SumOfratePerVehicle],0)
AS emissionsVehicle,
Nz(([VMT]![sourceTypePopulation]*[sourceTypeFraction]*[SumOfratePerVehicle])*
365,0) AS AnnualemissionsVehicle
FROM sourcetypepopulation INNER JOIN (ratepervehicle_state INNER JOIN VMT ON
(ratepervehicle_state.yearID = VMT.yearID) AND (ratepervehicle_state.StateID
= VMT.stateID)) ON (sourcetypepopulation.sourceTypeID =
ratepervehicle_state.sourceTypeID) AND (sourcetypepopulation.stateID =
ratepervehicle_state.StateID)
GROUP BY VMT.stateID, VMT.County, ratepervehicle_state.yearID,
ratepervehicle_state.monthID, ratepervehicle_state.hourID,
ratepervehicle_state.sourceTypeID, sourcetypepopulation.sourceTypeFraction,
VMT.SourceTypePopulation, ratepervehicle_state.pollutantID,
ratepervehicle_state.SumOfratePerVehicle;
```

5.3 Ramp Emissions

Ramp emission rates, calculated as discussed in Section 3, are multiplied by ramp VMT in each county, year and source type. This query is shown in Table 33.

Table 33: Ramp Emissions Query

```
SELECT VMT.stateID, VMT.County, VMT.yearID, hourvmtfraction.hourID, hourvmtfraction.sourceTypeID,
hourvmtfraction.hourVMTFraction, ramp_rate.pollutantID, VMT.[Ramp VMT], ([Ramp
VMT]*[hourVMTFraction])/13 AS HourlyRampVMT, ramp_rate.ramprate, [HourlyRampVMT]*[ramprate]
AS RampEmissions, ([HourlyRampVMT]*[ramprate])*340 AS RampEmissionsAnnual
FROM hourvmtfraction INNER JOIN (VMT INNER JOIN ramp_rate ON (VMT.stateID = ramp_rate.StateID)
AND (VMT.yearID = ramp_rate.yearID)) ON hourvmtfraction.hourID = ramp_rate.hourID
WHERE (((hourvmtfraction.roadTypeID)=4))
ORDER BY VMT.stateID, VMT.County, VMT.yearID, hourvmtfraction.hourID,
hourvmtfraction.sourceTypeID, ramp_rate.pollutantID;
```

5.4 Summarizing Results

Distance-based emissions by source type, vehicle-based emissions by source type, and ramp emissions by source type are summed by county, year and pollutant. This query is shown below. This is also where criteria may be set for limiting the results by state, county, year or pollutant. A sum of VMT and source type population is also useful as a verification that all steps were run properly. The appropriate monthID criteria should be set here. The annual average temperature profile is contained in April (monthID=4). July (monthID=7) should be used for summer weekday emissions.

Table 34:Results Query

```
SELECT EmissionsDistance_bySourceType.State, EmissionsDistance_bySourceType.County,
EmissionsDistance_bySourceType.yearID, EmissionsDistance_bySourceType.pollutantName,
Sum(EmissionsDistance_bySourceType.SumOfDailyVMT) AS SumOfSumOfDailyVMT,
Sum(RampEmissions_Query.HourlyRampVMT) AS SumOfHourlyRampVMT,
Sum(EmissionsDistance_bySourceType.SumOfAnnualizedVMT) AS SumOfSumOfAnnualizedVMT,
First(EmissionsVehicle_Query.SourceTypePopulation) AS FirstOfSourceTypePopulation,
Sum(EmissionsDistance_bySourceType.SumOfEmissionsDist) AS SumOfSumOfEmissionsDist,
Sum(Nz([emissionsVehicle],0)) AS EmissionsVeh, Sum(RampEmissions_Query.RampEmissions) AS
SumOfRampEmissions, Sum(EmissionsDistance_bySourceType.SumOfAnnualEmissionsDist) AS
SumOfSumOfAnnualEmissionsDist, Sum(Nz([AnnualemissionsVehicle],0)) AS AnnualEmissionsVeh,
Sum(RampEmissions_Query.RampEmissionsAnnual) AS SumOfRampEmissionsAnnual,
(([SumOfSumOfEmissionsDist]+[EmissionsVeh]+[SumOfHourlyRampVMT])/1000)*0.001102 AS
DailyEmissionsTONS,
(([SumOfSumOfAnnualEmissionsDist]+[AnnualEmissionsVeh]+[SumOfRampEmissionsAnnual])/1000)*0.0
01102 AS AnnualEmissionsTONS,
Sum([RampEmissions_Query]![HourlyRampVMT]+[EmissionsDistance_bySourceType]![SumOfDailyVMT]
) AS AllVMT
```

```
FROM (EmissionsDistance_bySourceType LEFT JOIN EmissionsVehicle_Query ON
(EmissionsDistance_bySourceType.pollutantID = EmissionsVehicle_Query.pollutantID) AND
(EmissionsDistance_bySourceType.sourceTypeID = EmissionsVehicle_Query.sourceTypeID) AND
(EmissionsDistance_bySourceType.hourID = EmissionsVehicle_Query.hourID) AND
(EmissionsDistance_bySourceType.monthID = EmissionsVehicle_Query.monthID) AND
(EmissionsDistance_bySourceType.yearID = EmissionsVehicle_Query.yearID) AND
(EmissionsDistance_bySourceType.County = EmissionsVehicle_Query.County)) INNER JOIN
RampEmissions_Query ON (EmissionsDistance_bySourceType.County = RampEmissions_Query.County)
AND (EmissionsDistance_bySourceType.yearID = RampEmissions_Query.yearID) AND
(EmissionsDistance_bySourceType.hourID = RampEmissions_Query.hourID) AND
(EmissionsDistance_bySourceType.sourceTypeID = RampEmissions_Query.sourceTypeID) AND
(EmissionsDistance_bySourceType.pollutantID = RampEmissions_Query.pollutantID)
GROUP BY EmissionsDistance_bySourceType.State, EmissionsDistance_bySourceType.County,
EmissionsDistance_bySourceType.yearID, EmissionsDistance_bySourceType.pollutantName,
EmissionsDistance_bySourceType.monthID, EmissionsDistance_bySourceType.pollutantID
HAVING (((EmissionsDistance_bySourceType.monthID)=4));
```

Regional Air Quality Analyses for Ozone, $PM_{2.5}$, and Regional Haze:

Final Technical Support Document

April 25, 2008

States of Illinois, Indiana, Michigan, Ohio, and Wisconsin

Table of Contents

EXECUTIVE SUMMARY

States in the upper Midwest face a number of air quality challenges. More than 50 counties are currently classified as nonattainment for the 8-hour ozone standard and 60 for the fine particle ($PM_{2.5}$) standard (1997 versions). A map of these nonattainment areas is provided in the figure below. In addition, visibility impairment due to regional haze is a problem in the larger national parks and wilderness areas (i.e., Class I areas). There are 156 Class I areas in the U.S., including two in northern Michigan.

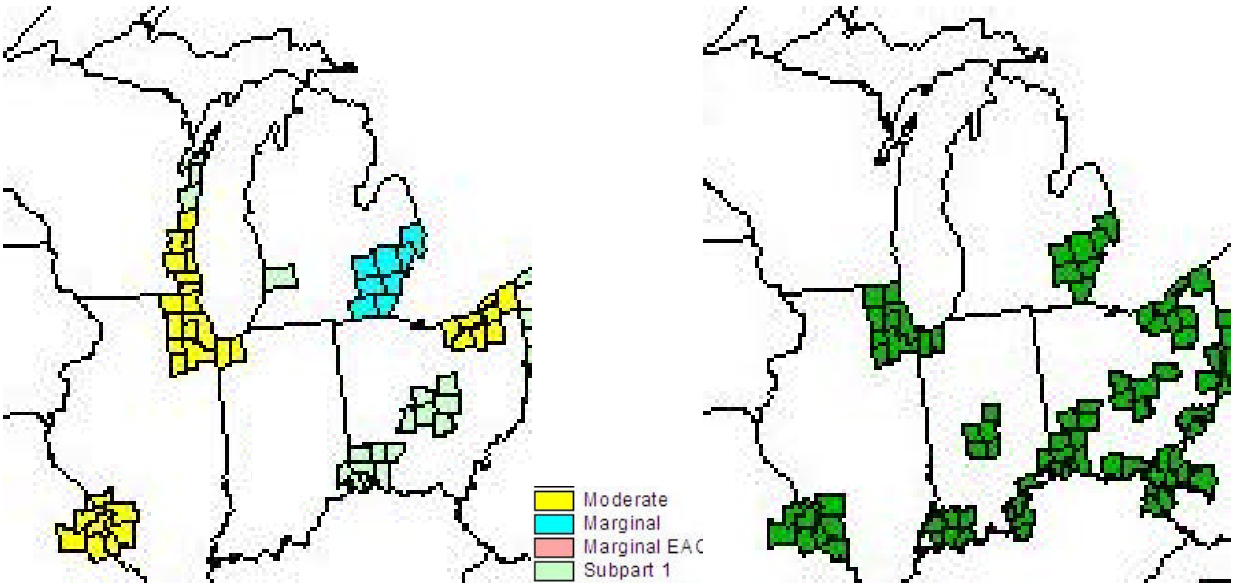


Figure i. Current nonattainment counties for ozone (left) and $PM_{2.5}$ (right)

To support the development of State Implementation Plans (SIPs) for ozone, $PM_{2.5}$, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin, technical analyses were conducted by the Lake Michigan Air Directors Consortium (LADCO), its member states, and various contractors. The analyses include preparation of regional emissions inventories and meteorological data, evaluation and application of regional chemical transport models, and collection and analysis of ambient monitoring data.

Monitoring data were analyzed to produce a conceptual understanding of the air quality problems. Key findings of the analyses include:

Ozone

- Current monitoring data (2005-2007) show about 20 sites in violation of the 8-hour ozone standard of 85 parts per billion (ppb). Historical ozone data show a steady downward trend over the past 15 years, especially since 2001-2003, due likely to federal and state emission control programs.

- Ozone concentrations are strongly influenced by meteorological conditions, with more high ozone days and higher ozone levels during summers with above normal temperatures.

- Inter- and intra-regional transport of ozone and ozone precursors affects many portions of the five states, and is the principal cause of nonattainment in some areas far from population or industrial centers.

$PM_{2.5}$

- Current monitoring data (2005-2007) show 30 sites in violation of the annual $PM_{2.5}$ standard of 15 ug/m^3. Nonattainment sites are characterized by an elevated regional background (about 12 – 14 ug/m^3) and a significant local (urban) increment (about 2 – 3 ug/m^3). Historical $PM_{2.5}$ data show a slight downward trend since deployment of the $PM_{2.5}$ monitoring network in 1999.

- $PM_{2.5}$ concentrations are also influenced by meteorology, but the relationship is more complex and less well understood compared to ozone.

- On an annual average basis, $PM_{2.5}$ chemical composition consists mostly of sulfate, nitrate, and organic carbon in similar proportions.

Haze

- Current monitoring data (2000-2004) show visibility levels in the Class I areas in northern Michigan are on the order of 22 – 24 deciviews. The goal of EPA's visibility program is to achieve natural conditions, which is about 12 deciviews for these Class I areas, by the year 2064.

- Visibility impairment is dominated by sulfate and nitrate.

Air quality models were applied to support the regional planning efforts. Two base years were used in the modeling analyses: 2002 and 2005. Basecase modeling was conducted to evaluate model performance (i.e., assess the model's ability to reproduce observed concentrations). This exercise was intended to build confidence in the model prior to its use in examining control strategies. Model performance for ozone and $PM_{2.5}$ was found to be generally acceptable.

Future year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Based on the modeling and other supplemental analyses, the following general conclusions can be made:

- Existing controls are expected to produce significant improvement in ozone and $PM_{2.5}$ concentrations and visibility levels.

- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).

- Modeling suggests that most sites are expected to meet the current 8-hour ozone standard by the applicable attainment date, except for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.

- Modeling suggests that most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.

  The regional modeling for $PM_{2.5}$ does not include air quality benefits expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$.

- These findings of residual nonattainment for ozone and $PM_{2.5}$ are supported by current (2005 – 2007) monitoring data which show significant nonattainment in the region (e.g., peak ozone design values on the order of 90 – 93 ppb, and peak $PM_{2.5}$ design values on the order of 16 - 17 ug/m^3). It is unlikely that sufficient emission reductions will occur in the next couple of years to provide for attainment at all sites.

- Attainment at most sites by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). If either of these conditions is not met, then attainment may be less likely.

- Modeling suggests that the new $PM_{2.5}$ 24-hour standard and the new lower ozone standard will not be met at several sites, even by 2018, with existing controls.

- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018 based on existing controls, including those in northern Michigan and some in the northeastern U.S. Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018. These results, along with information on the costs of compliance, time necessary for compliance, energy and non air quality environmental impacts of compliance, and remaining useful life of existing sources, should be considered by the states in setting reasonable progress goals for regional haze.

Section 1.0 Introduction

This Technical Support Document summarizes the final air quality analyses conducted by the Lake Michigan Directors Consortium (LADCO)[1] and its contractors to support the development of State Implementation Plans (SIPs) for ozone, fine particles ($PM_{2.5}$), and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin. The analyses include preparation of regional emissions inventories and meteorological modeling data for two base years (2002 and 2005), evaluation and application of regional chemical transport models, and analysis of ambient monitoring data.

Two aspects of the analyses should be emphasized. First, a regional, multi-pollutant approach was taken in addressing ozone, $PM_{2.5}$, and haze for technical reasons (e.g., commonality in precursors, emission sources, atmospheric processes, transport influences, and geographic areas of concern), and practical reasons (e.g., more efficient use of program resources). Furthermore, EPA has consistently encouraged multi-pollutant planning in its rule for the haze program (64 FR 35719), and its implementation guidance for ozone (70 FR 71663) and $PM_{2.5}$ (72 FR 20609). Second, a weight-of-evidence approach was taken in considering the results of the various analyses (i.e., two sets of modeling results -- one for a 2002 base year and one for a 2005 base year -- and ambient data analyses) in order to provide a more robust assessment of expected future year air quality.

The report is organized in the following sections. This Introduction provides an overview of regulatory requirements and background information on regional planning. Section 2 reviews the ambient monitoring data and presents a conceptual model of ozone, $PM_{2.5}$, and haze for the region. Section 3 discusses the air quality modeling analyses, including development of the key model inputs (emissions inventory and meteorological data), and basecase model performance evaluation. A modeled attainment demonstration for ozone and $PM_{2.5}$ is presented in Section 4, along with relevant data analyses considered as part of the weight-of-evidence determination. Section 5 documents the reasonable progress assessment for regional haze, along with relevant data analyses considered as part of the weight-of-evidence determination. Finally, key study findings are reviewed and summarized in Section 6.

1.1 SIP Requirements

For ozone, EPA promulgated designations on April 15, 2004 (69 FR 23858, April 30, 2004). In the 5-state region, more than 100 counties were designated as nonattainment.[2] The designations became effective on June 15, 2004. SIPs for ozone were due no later than three years from the effective date of the nonattainment designations (i.e., by June 2007). The attainment date for ozone varies as a function of nonattainment classification. For the region, the attainment dates are either June 2007 (marginal nonattainment areas), June 2009 (basic nonattainment areas), or June 2010 (moderate nonattainment areas).

[1] A sub-entity of LADCO, known as the Midwest Regional Planning Organization (MRPO), is responsible for the regional haze activities of the multi-state organization.

[2] Based on more recent air quality data, many counties in Indiana, Michigan, and Ohio were subsequently redesignated as attainment. As of December 31, 2007, there are 53 counties designated as nonattainment in the region.

For $PM_{2.5}$, EPA promulgated designations on December 17, 2004 (70 FR 944, January 5, 2005). In the 5-state region, 70 counties were designated as nonattainment.[3] The designations became effective on April 5, 2005. SIPs for $PM_{2.5}$ are due no later than three years from the effective date of the nonattainment designations (per section 172(b) of the Clean Air Act) (i.e., by April 2008) and for haze no later than three years after the date on which the Administrator promulgated the $PM_{2.5}$ designations (per the Omnibus Appropriations Act of 2004) (i.e., by December 2007). The applicable attainment date for $PM_{2.5}$ nonattainment areas is five years from the date of the nonattainment designation (i.e., by April 2010).

For haze, the Clean Air Act sets "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." There are 156 Class I areas, including two in northern Michigan: Isle Royale National Park and Seney National Wildlife Refuge[4]. EPA's visibility rule (64 FR 35714, July 1, 1999) requires reasonable progress in achieving "natural conditions" by the year 2064. As noted above, the first regional haze SIP was due in December 2007 and must address the initial 10-year implementation period (i.e., reasonable progress by the year 2018). SIP requirements (pursuant to 40 CFR 51.308(d)) include setting reasonable progress goals, determining baseline conditions, determining natural conditions, providing a long-term control strategy, providing a monitoring strategy (air quality and emissions), and establishing BART emissions limitations and associated compliance schedule.

1.2 Organization

LADCO was established by the States of Illinois, Indiana, Michigan, and Wisconsin in 1989. The four states and EPA signed a Memorandum of Agreement (MOA) that initiated the Lake Michigan Ozone Study (LMOS) and identified LADCO as the organization to oversee the study. Additional MOAs were signed by the States in 1991 (to establish the Lake Michigan Ozone Control Program), January 2000 (to broaden LADCO's responsibilities), and June 2004 (to update LADCO's mission and reaffirm the commitment to regional planning). In March 2004, Ohio joined LADCO. LADCO consists of a Board of Directors (i.e., the State Air Directors), a technical staff, and various workgroups. The main purposes of LADCO are to provide technical assessments for and assistance to its member states, and to provide a forum for its member states to discuss regional air quality issues.

MRPO is a similar entity led by the five LADCO States and involves the federally recognized tribes in Michigan and Wisconsin, EPA, and Federal Land Managers (i.e., National Park Service, U.S. Fish & Wildlife Agency, and U.S. Forest Service). In October 2000, the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin signed an MOA that established the MRPO. An operating principles document for MRPO, which describe the roles and responsibilities of states, tribes, federal agencies, and stakeholders, was issued in March 2001. MRPO has a similar purpose as LADCO, but is focused on visibility impairment due to regional haze in the Federal Class I areas located inside the borders of the five states, and the impact of emissions from the five states on visibility impairment due to regional haze in the Federal Class I areas located outside the borders of the five states. MRPO works cooperatively with the Regional Planning Organizations (RPOs) representing other parts of the country. The RPOs sponsored several

[3] USEPA subsequently adjusted the final designations, which resulted in 63 counties in the region being designated as nonattainment (70 FR 19844, April 15, 2005).

[4] Although Rainbow Lake in northern Wisconsin is also a Class I area, the visibility rule does not apply because the Federal Land Manager determined that visibility is not an air quality related value there.

joint projects and, with assistance by EPA, maintain regular contact on technical and policy matters.

1.3 Technical Work: Overview

To ensure the reliability and effectiveness of its planning process, LADCO has made data collection and analysis a priority. More than $7M in RPO grant funds were used for special purpose monitoring, preparing and improving emissions inventories, and conducting air quality analyses[5]. An overview of the technical work is provided below.

Monitoring: Numerous monitoring projects were conducted to supplement on-going state and local air pollution monitoring. These projects include rural monitoring (e.g., comprehensive sampling in the Seney National Wildlife Refuge and in Bondville, IL); urban monitoring (e.g., continuation of the St. Louis Supersite); aloft (aircraft) measurements; regional ammonia monitoring; and organic speciation sampling in Seney, Bondville, and five urban areas.

Emissions: Baseyear emissions inventories were prepared for 2002 and 2005. States provided point source and area source emissions data, and MOBILE6 input files and mobile source activity data. LADCO and its contractors developed the emissions data for other source categories (e.g., select nonroad sources, ammonia, fires, and biogenics) and processed the data for input into an air quality model. To support control strategy modeling, future year inventories were prepared. The future years of interest include 2008 (planning year to address the 2009 attainment year for basic ozone nonattainment ares), 2009 (planning year to address the 2010 attainment year for $PM_{2.5}$ and moderate ozone nonattainment areas), 2012 (planning to address a 2013 alternative attainment date), and 2018 (first milestone year for regional haze).

Air Quality Analyses: The weight-of-evidence approach relies on data analysis and modeling. Air quality data analyses were used to provide both a conceptual model (i.e., a qualitative description of the ozone, $PM_{2.5}$, and regional haze problems) and supplemental information for the attainment demonstration. Given uncertainties in emissions inventories and modeling, especially for $PM_{2.5}$, these data analyses are a necessary part of the overall technical support.

Modeling includes baseyear analyses for 2002 and 2005 to evaluate model performance and future year strategy analyses to assess candidate control strategies. The analyses were conducted in accordance with EPA's modeling guidelines (EPA, 2007a). The PM/haze modeling covers the full calendar year (2002 and 2005) for an eastern U.S. 36 km domain, while the ozone modeling focuses on the summer period (2002 and 2005) for a Midwest 12 km subdomain. The same model (CAMx) was used for ozone, $PM_{2.5}$, and regional haze.

[5] Since 1999, MRPO has received almost $10M in RPO grant funds from USEPA.

Section 2.0 Ambient Data Analyses

An extensive network of air quality monitors in the 5-state region provides data for ozone (and its precursors), $PM_{2.5}$ (both total mass and individual chemical species), and visibility. These data are used to determine attainment/nonattainment designations, support SIP development, and provide air quality information to public (see, for example, www.airnow.gov).

Analyses of the data were conducted to produce a conceptual model, which is a qualitative summary of the physical, chemical, and meteorological processes that control the formation and distribution of pollutants in a given region. This section reviews the relevant data analyses and describes our understanding of ozone, $PM_{2.5,}$ and regional haze with respect to current conditions, data variability (spatial, temporal, and chemical), influence of meteorology (including transport patterns), precursor sensitivity, and source culpability.

2.1 Ozone

In 1979, EPA adopted an ozone standard of 0.12 ppm, averaged over a 1-hour period. This standard is attained when the number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is equal to or less than 1.0, averaged over a 3-year period, which generally reflects a design value (i.e., the 4th highest daily 1-hour value over a 3-year period) less than 0.12 ppm.

In 1997, EPA tightened the ozone standard to 0.08 ppm, averaged over an 8-hour period[6]. The standard is attained if the 3-year average of the 4th-highest daily maximum 8-hour average ozone concentrations (i.e., the design value) measured at each monitor within an area is less than 0.08 ppm (or 85 ppb).

Current Conditions: A map of the 8-hour ozone design values at each monitoring site in the region for the 3-year period 2005-2007 is shown in Figure 1. The "hotter" colors represent higher concentrations, where yellow and orange dots represent sites with design values above the standard. Currently, there are 19 sites in violation of the 8-hour ozone NAAQS in the 5-state region, including sites in the Lake Michigan area, Detroit, Cleveland, Cincinnati, and Columbus.

Table 1 provides the 4th-highest daily 8-hour ozone values and the associated design values since 2001 for several high monitoring sites throughout the region.

[6] On March 12, 2008, USEPA further tightened the 8-hour ozone standard to increase public health protection and prevent environmental damage from ground-level ozone. USEPA set the primary (health) standard and secondary (welfare) standard at the same level: 0.075 ppm (75 ppb), averaged over an 8-hour period.

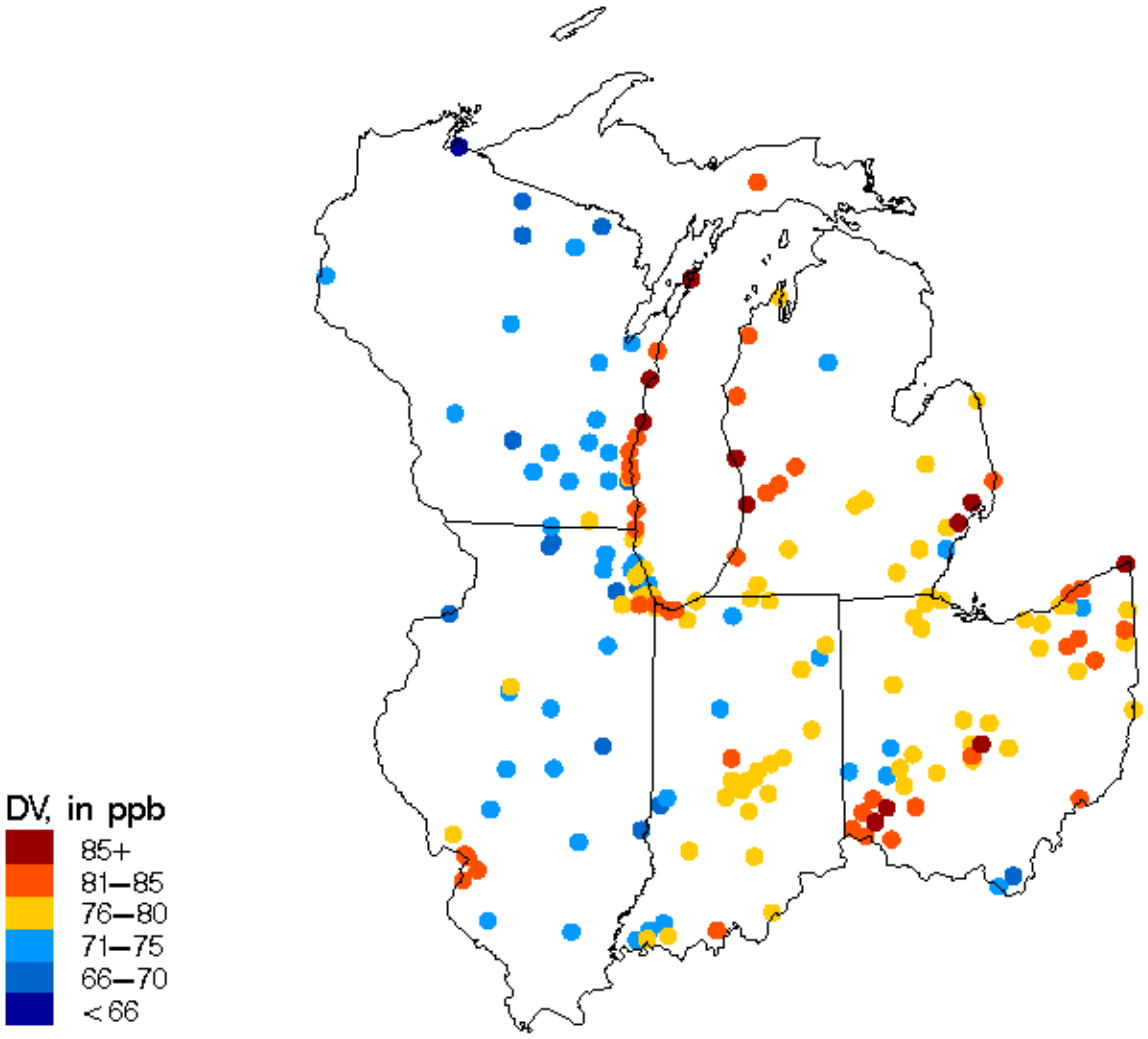


Figure 1. 8-hour ozone design values (2005-2007)

Table 1. Ozone Data for Select Sites in 5-State Region

Key Sites	4th High 8-hour Value								Design Values				
	'01	'02	'03	'04	'05	'06	'07		'01-'03	'02-'04	'03-'05	'04-'06	'05-'07
Lake Michigan Area													
Chiwaukee	99	116	88	78	93	79	85		**101**	**94**	**86**	83	**85**
Racine	92	111	82	69	95	71	77		**95**	**87**	82	78	81
Milwaukee-Bayside	93	99	92	73	93	73	83		**94**	**88**	**86**	79	83
Harrington Beach	102	93	99	72	94	72	84		**98**	**88**	**88**	79	83
Manitowoc	97	83	92	74	95	78	85		**90**	83	**87**	82	**86**
Sheboygan	102	105	93	78	97	83	88		**100**	**92**	**89**	**86**	**89**
Kewaunee	90	92	97	73	88	76	85		**93**	**87**	**86**	*79*	83
Door County	95	95	93	78	101	79	92		**94**	**88**	**90**	**86**	**90**
Hammond	90	101	81	67	87	75	77		**90**	83	78	76	79
Whiting				64	88	81	88					77	**85**
Michigan City	90	107	82	70	84	75	73		**93**	**86**	78	76	77
Ogden Dunes	85	101	77	69	90	70	84		**87**	82	78	76	81
Holland	92	105	96	79	94	91	94		**97**	**93**	**89**	**88**	**93**
Jenison	86	93	91	69	86	83	88		**90**	84	82	79	**85**
Muskegon	95	96	94	70	90	90	86		**95**	**86**	84	83	**88**
Indianapolis Area													
Noblesville	88	101	101	75	87	77	84		**96**	**92**	**87**	79	82
Fortville	89	101	92	72	80	75	81		**94**	**88**	81	75	78
Fort B. Harrison	87	100	91	73	80	76	83		**92**	**88**	81	76	79
Detroit Area													
New Haven	95	95	102	81	88	78	93		**97**	**92**	**90**	82	**86**
Warren	94	92	101	71	89	78	91		**95**	**88**	**87**	79	**86**
Port Huron	84	100	87	74	88	78	89		**90**	**87**	83	80	**85**
Cleveland Area													
Ashtabula (Conneaut)	97	103	99	81	93	86	92		**99**	**94**	**91**	**86**	**90**
Notre Dame (Geauga)	99	115	97	75	88	70	68		**103**	**95**	**86**	77	75
Eastlake (Lake)	89	104	92	79	97	83	74		**95**	**91**	**89**	**86**	84
Akron (Summit)	98	103	89	77	89	77	91		**96**	**89**	**85**	81	**85**
Cincinnati Area													
Wilmington (Clinton)	93	99	96	78	83	81	82		**96**	**91**	**85**	80	82
Sycamore (Hamilton)	88	100	93	76	89	81	90		**93**	**89**	**86**	82	**86**
Hamilton (Butler)	83	100	94	75	86	79	91		**92**	**89**	**85**	80	**85**
Middleton (Butler)	87	98	83	76	88	76	91		**89**	**85**	82	80	**85**
Lebanon (Warren)	85	98	95	81	92	86	88		**92**	**91**	**89**	**86**	**88**
Columbus Area													
London (Madison)	84	97	90	75	81	76	83		**90**	**87**	82	77	80
New Albany (Franklin)	90	103	94	78	92	82	87		**95**	**91**	**88**	84	**87**
Franklin (Franklin)	83	99	84	73	86	79	79		**88**	**85**	81	79	81
Ohio Other Areas													
Marietta (Washington)	85	95	80	77	88	81	86		**86**	84	81	82	**85**
St. Louis Area													
W. Alton (MO)	85	99	91	77	89	91	89		**91**	**89**	**85**	**85**	**89**
Orchard (MO)	88	98	90	76	92	92	83		**92**	**88**	**86**	**86**	**89**
Sunset Hills (MO)	88	98	88	70	89	80	89		**91**	**85**	82	79	**86**
Arnold (MO)	86	93	82	70	92	79	87		**87**	81	81	80	**86**
Margaretta (MO)	80	98	90	72	91	76	91		**89**	**86**	84	79	**86**
Maryland Heights (MO)					88	84	94						**88**

Meteorology and Transport: Most pollutants exhibit some dependence on meteorological factors, especially wind direction, because that governs which sources are upwind and thus most influential on a given sample. Ozone is even more dependent, since its production is driven by high temperatures and sunlight, as well as precursor concentrations (see, for example, Figure 2).

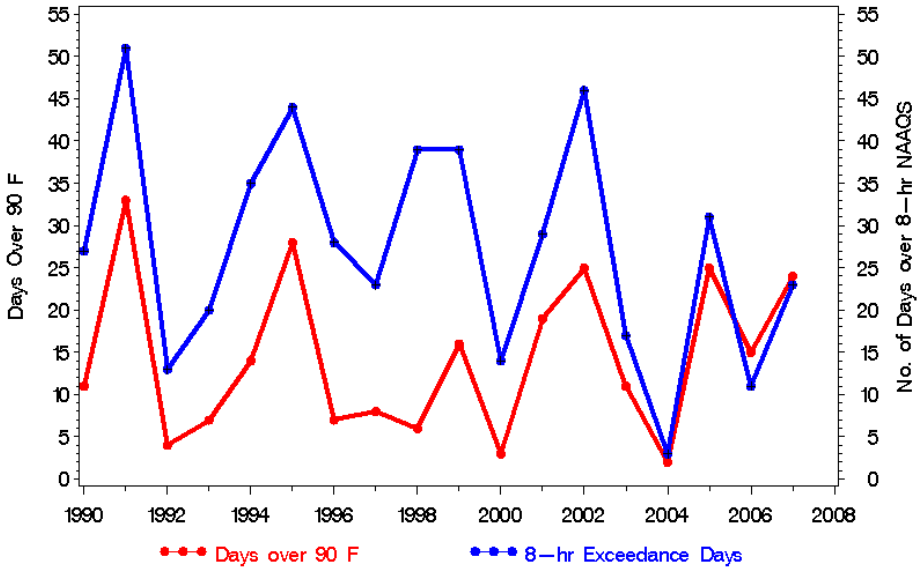


Figure 2. Number of hot days and 8-hour "exceedance" days in 5-state region

Qualitatively, ozone episodes in the region are associated with hot weather, clear skies (sometimes hazy), low wind speeds, high solar radiation, and southerly to southwesterly winds. These conditions are often a result of a slow-moving high pressure system to the east of the region. The relative importance of various meteorological factors is discussed later in this section.

Transport of ozone (and its precursors) is a significant factor and occurs on several spatial scales. Regionally, over a multi-day period, somewhat stagnant summertime conditions can lead to the build-up in ozone and ozone precursor concentrations over a large spatial area. This pollutant air mass can be advected long distances, resulting in elevated ozone levels in locations far downwind. An example of such an episode is shown in Figure 3.

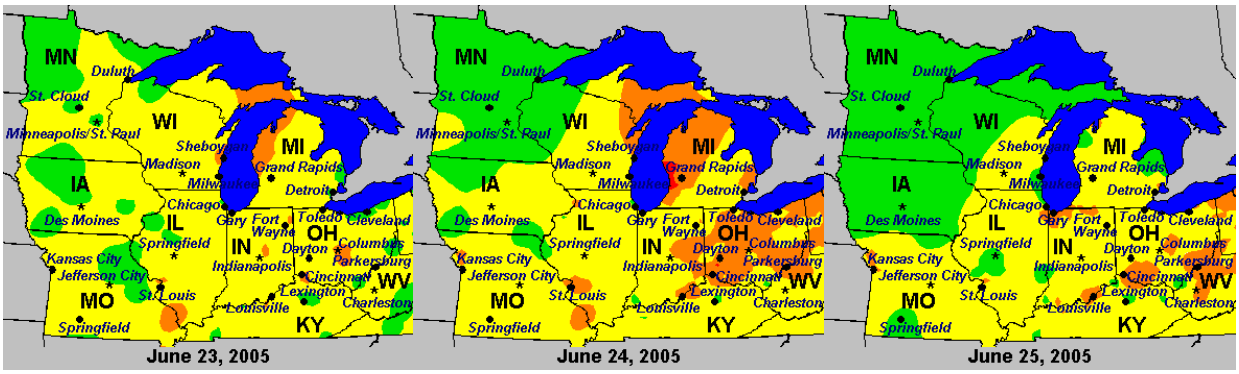


Figure 3. Example of elevated regional ozone concentrations (June 23 – 25, 2005)

Note: hotter colors represent higher concentrations, with orange representing concentrations above the 8-hour standard

Locally, emissions from urban areas add to the regional background leading to ozone concentration hot spots downwind. Depending on the synoptic wind patterns (and local land-lake breezes), different downwind areas are affected (see, for example, Figure 4).

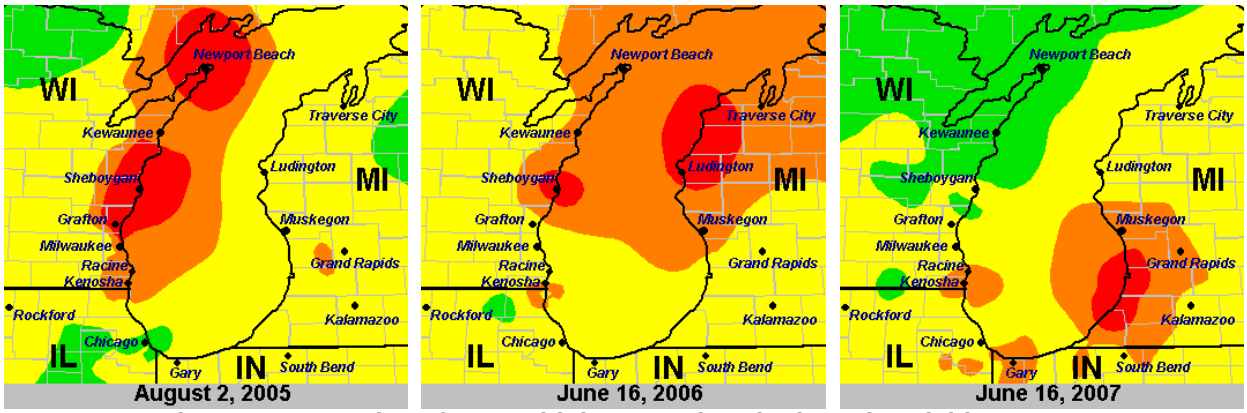


Figure 4. Examples of recent high ozone days in the Lake Michigan area

Note: hotter colors represent higher concentrations, with orange representing concentrations above the 8-hour standard

Aloft (aircraft) measurements in the Lake Michigan area also provide evidence of elevated regional background concentrations and "plumes" from urban areas. For one example summer day (August 20, 2003 – see Figure 5), the incoming background ozone levels were on the order of 80 – 100 ppb and the downwind ozone levels over Lake Michigan were on the order of 100 - 150 ppb (STI, 2004).

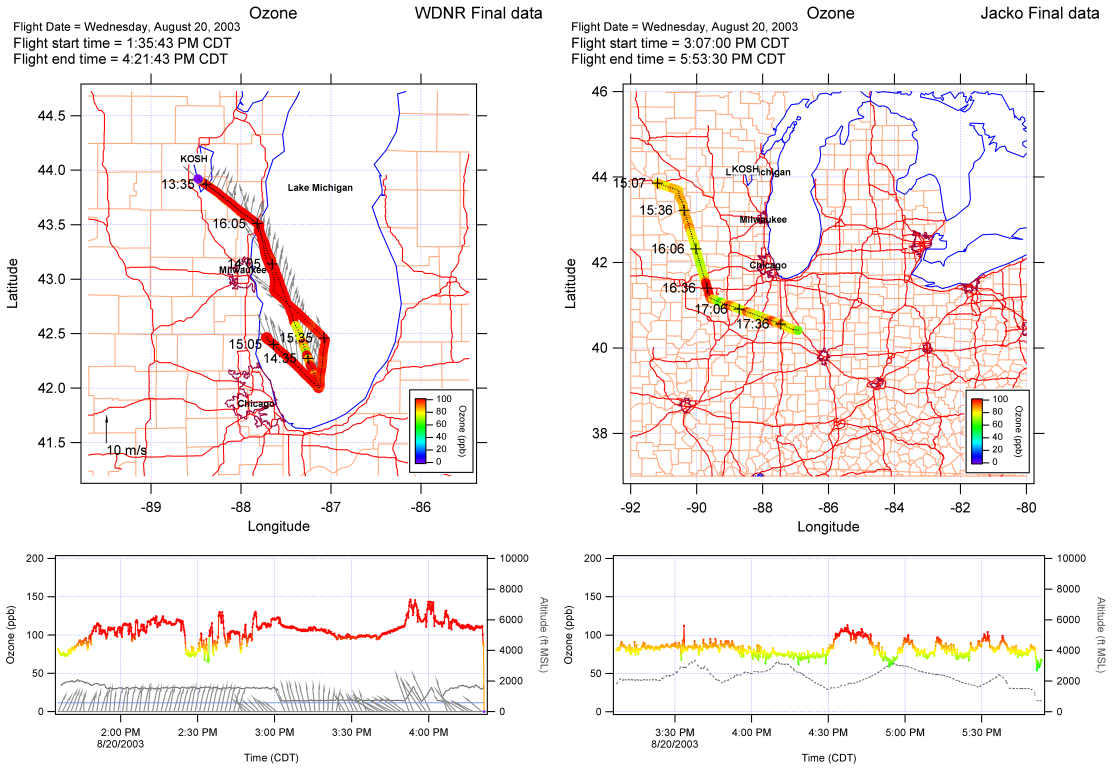


Figure 5. Aircraft ozone measurements over Lake Michigan (left) and along upwind boundary (right) – August 20, 2003 (Note: aircraft measurements reflect instantaneous values)

As discussed in Section 4, residual nonattainment is projected in at least one area in the 5-state region –i.e., western Michigan. To understand the source regions likely impacting high ozone concentrations in western Michigan and estimate the impact of these source regions, two simple transport-related analyses were performed.

First, back trajectories were constructed using the HYSPLIT model for high ozone days (8-hour peak > 80 ppb) during the period 2002-2006 in western Michigan to characterize general transport patterns. Composite trajectory plots for all high ozone days based on data from three sites (Cass County, Holland, and Muskegon) are provided in Figure 6. The plots point back to areas located to the south-southwest (especially, northeastern Illinois and northwestern Indiana) as being upwind on these high ozone days.

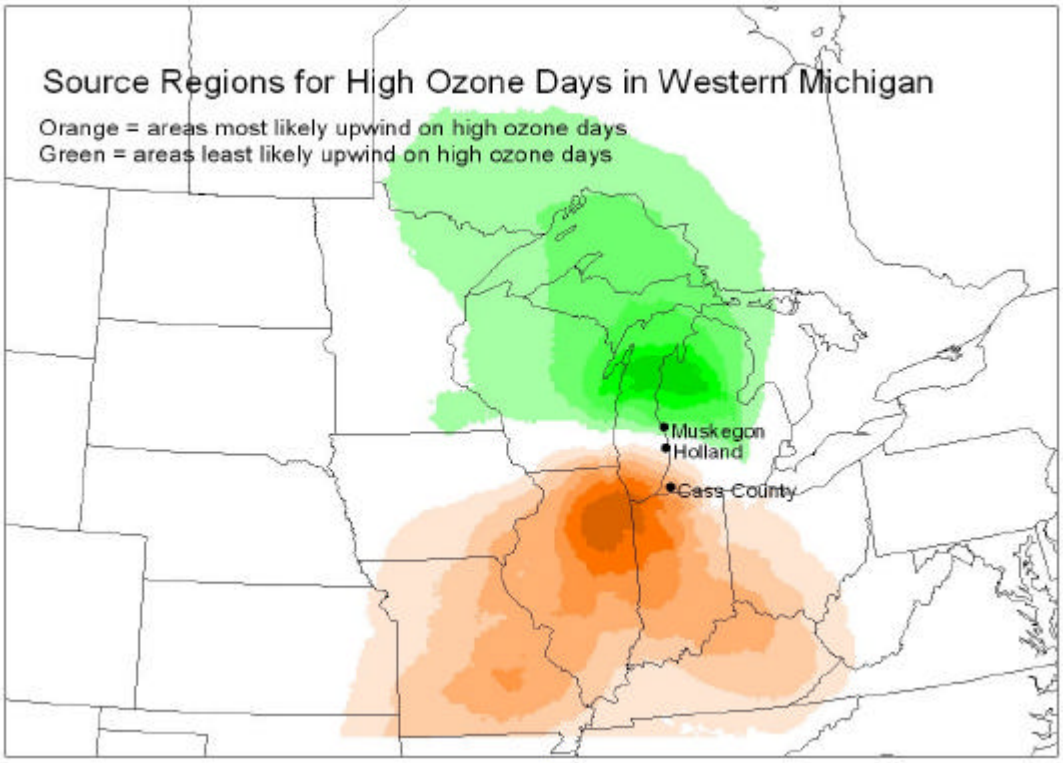


Figure 6 Back trajectory analysis showing upwind areas associated with high ozone concentrations

Second, to assess the impact from Chicago/NW Indiana, Blanchard (2005a) compared ozone concentrations upwind (Braidwood, IL), within Chicago (ten sites in the City), and downwind (Holland and Muskegon) for days in 1999 – 2002 with southwesterly winds - i.e., transport towards western Michigan. Figure 7 shows the distribution of daily peak 8-hour ozone concentrations by day-of-week, with a line connecting the mean values. The difference between day-of-week mean values at downwind and upwind sites indicates that Chicago/NW Indiana contributes about 10-15 ppb to downwind ozone levels.

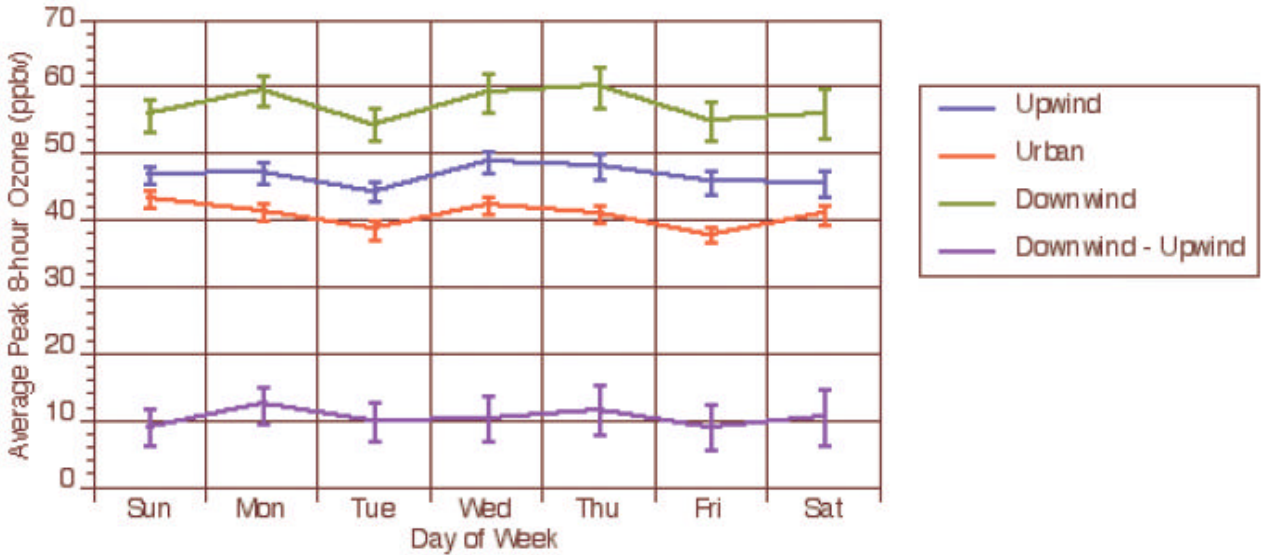


Figure 7. Mean day-of-week peak 8-hour ozone concentrations at sites upwind, within, and downwind of Chicago, 1999 – 2002 (southwesterly wind days)

Based on this information, the following key findings related to transport can be made:

- Ozone transport is a problem affecting many portions of the eastern U.S. The Lake Michigan area (and other areas in the LADCO region) both receive high levels of incoming (transported) ozone and ozone precursors from upwind source areas on many hot summer days, and contribute to the high levels of ozone and ozone precursors affecting downwind receptor areas.

- The presence of a large body of water (i.e., Lake Michigan) influences for the formation and transport of ozone in the Lake Michigan area. Depending on large-scale synoptic winds and local-scale lake breezes, different parts of the area experience high ozone concentrations. For example, under southerly flow, high ozone can occur in eastern Wisconsin, and under southwesterly flow, high ozone can occur in western Michigan.

- Downwind shoreline areas around Lake Michigan are affected by both regional transport of ozone and subregional transport from major cities in the Lake Michigan area. Counties along the western shore of Michigan (from Benton Harbor to Traverse City, and even as far north as the Upper Peninsula) are impacted by high levels of incoming (transported) ozone.

Data Variability: Since 1980, considerable progress has been made to meet the previous 1-hour ozone standard. Figure 8 shows the decline in both the 1-hour and 8-hour design values for the 5-state LADCO region over the last 25 years.

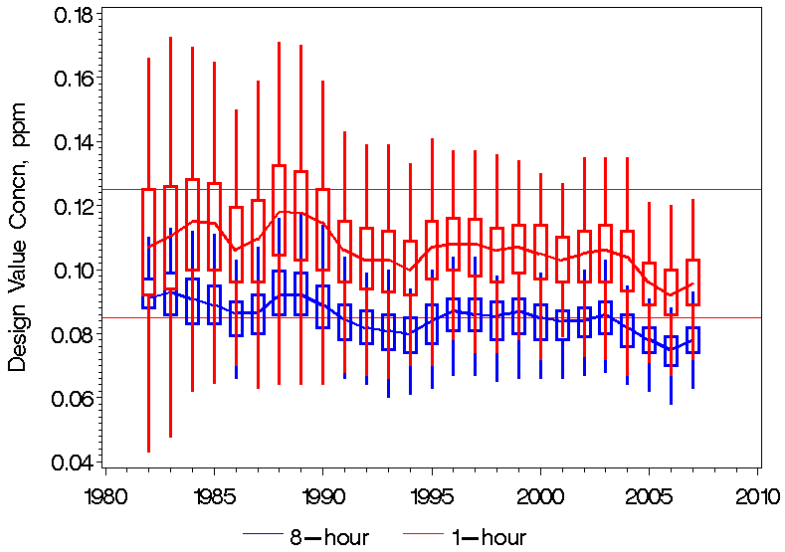


Figure 8 Ozone design value trends in 5-State region

The trend is more dramatic for the higher ozone sites in the 5-state region (see Figure 9). This plot shows a pronounced downward trend in the design value since the 2001-2003 period, due, in part, to the very low 4th high values in 2004.

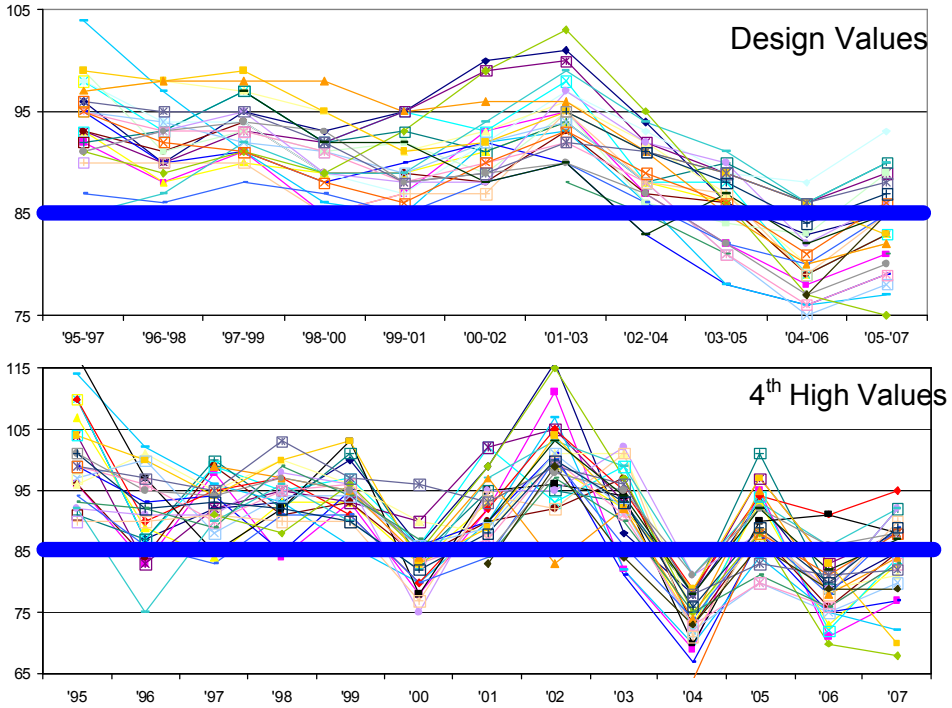


Figure 9. Trend in ozone design values and 4th high values for higher ozone sites in region

The improvement in ozone concentrations is also seen in the decrease in the number of sites measuring nonattainment over the past 15 years in the Lake Michigan area (see Figure 10).

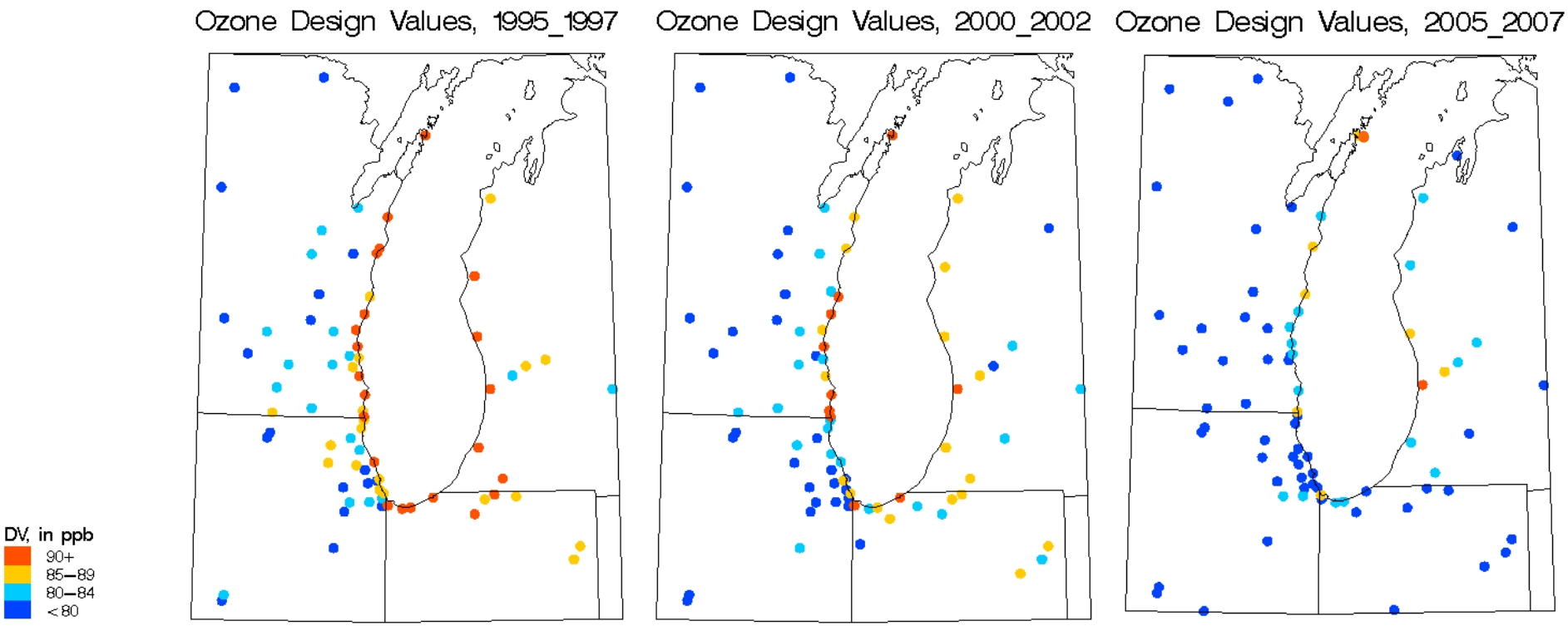


Figure 10. Ozone design value maps for 1995-1997, 2000-2002, and 2005-2007

Given the effect of meteorology on ambient ozone levels, year-to-year variations in meteorology can make it difficult to assess trends in ozone air quality. Two approaches were considered to adjust ozone trends for meteorological influences: an air quality-meteorology statistical model developed by EPA (i.e., Cox method), and statistical grouping of meteorological variables performed by LADCO (i.e., Classification and Regression Trees, or CART).

Cox Method: This method uses a statistical model to 'remove' the annual effect of meteorology on ozone (Cox and Chu, 1993). A regression model was fit to the 1997-2007 data to relate daily peak 8-hour ozone concentrations to six daily meteorological variables plus seasonal and annual factors (Kenski, 2008a). Meteorological variables included were daily maximum temperature, mid-day average relative humidity, morning and afternoon wind speed and wind direction. The model is then used to predict 4th high ozone values. By holding the meteorological effects constant, the long term trend can be examined independently of meteorology. Presumably, any trend reflects changes in emissions of ozone precursors.

Figure 11a shows the meteorologically-adjusted 4th high ozone concentrations for several monitors near major urban areas in the region. The plots indicate a general downward trend since the late 1990s for most cities, indicating that recent emission reductions have had a positive effect in improving ozone air quality.

A similar model was run to examine meteorologically adjusted trends in seasonal average ozone. This model incorporates more meteorological variables, including rain and long-distance transport (direction and distance). Model development was documented in Camalier et al., 2007. The seasonal average trends are shown in Figure 11b. Trends determined by seasonal model for the same set of sites examined above are consistent with those developed by the 4th high model.

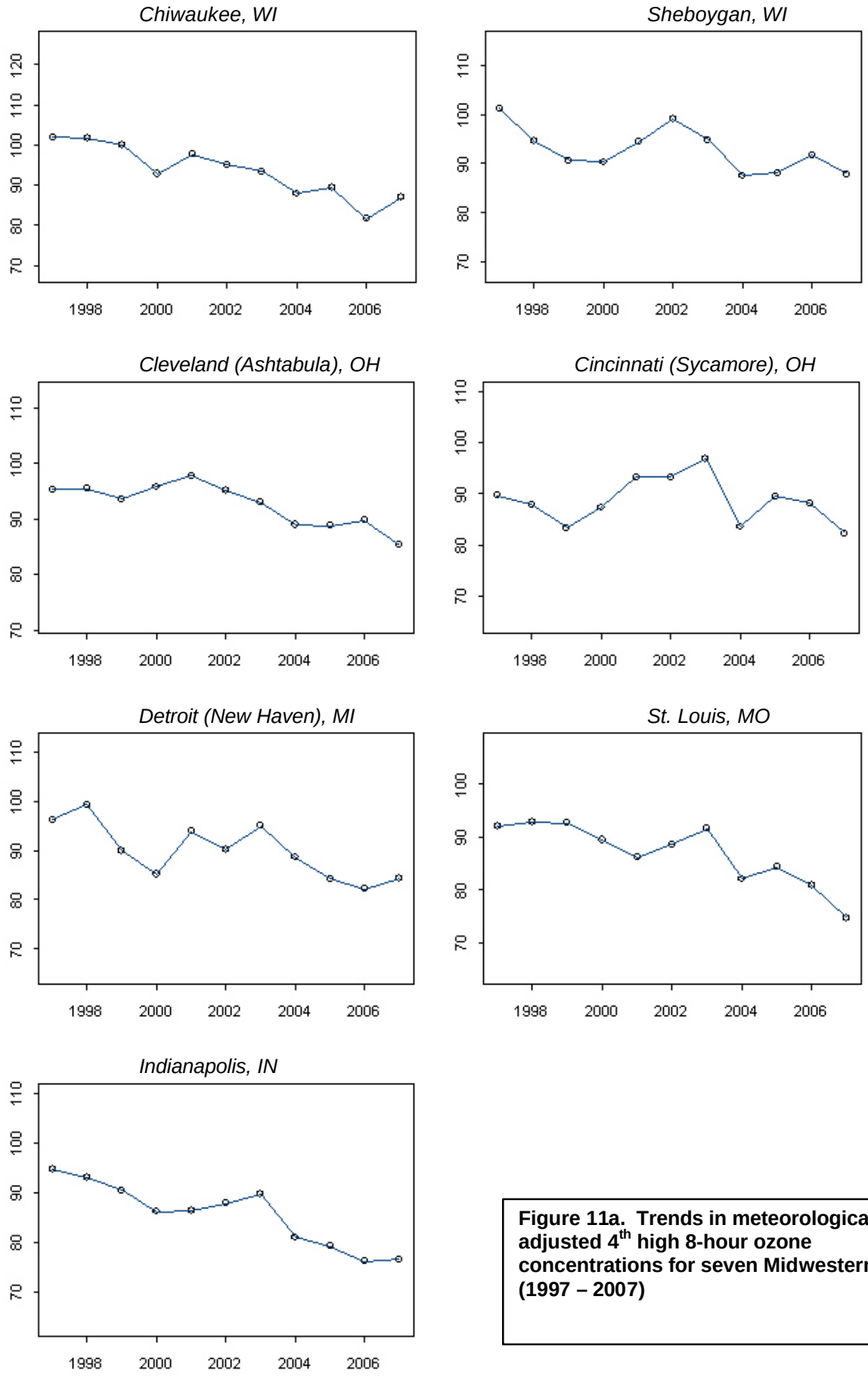


Figure 11a. Trends in meteorologically adjusted 4th high 8-hour ozone concentrations for seven Midwestern sites (1997 – 2007)

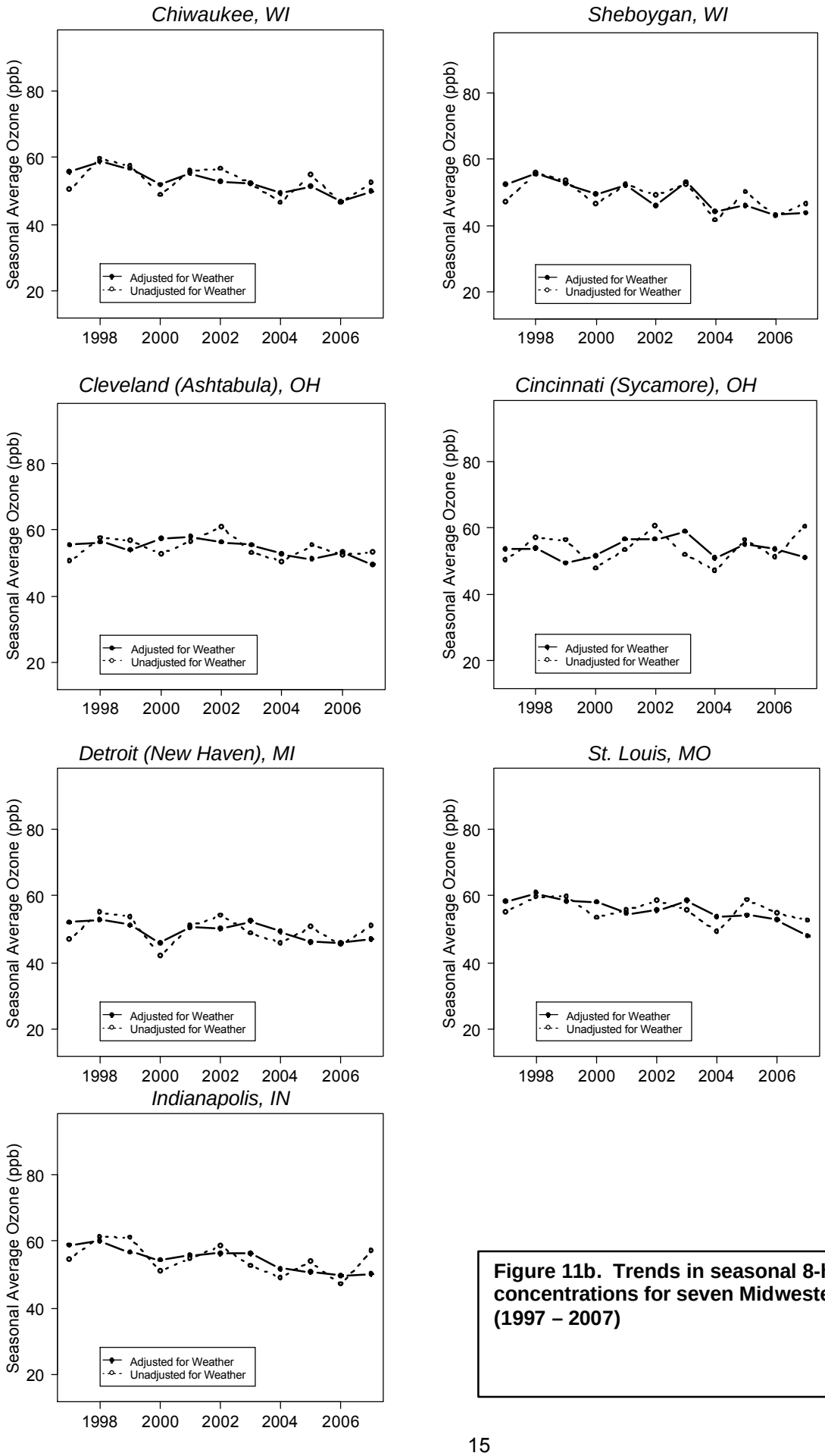


Figure 11b. Trends in seasonal 8-hour ozone concentrations for seven Midwestern sites (1997 – 2007)

CART: Classification and Regression Tree (CART) analysis is another statistical technique which partitions data sets into similar groups (Breiman et al., 1984). CART analysis was performed using data for the period 1995-2007 for 22 selected ozone monitors with current 8-hour design values close to or above the standard (Kenski, 2008b). The CART model searches through 60 meteorological variables to determine which are most efficient in predicting ozone. Although the exact selection of predictive variables changes from site to site, the most common predictors were temperature, wind direction, and relative humidity. Only occasionally were upper air variables, transport time or distance, lake breeze, or other variables significant. (Note, the ozone and meteorological data for the CART analysis are the same as used in the EPA/Cox analysis.)

For each monitor, regression trees were developed that classify each summer day (May-September) by its meteorological conditions. Similar days are assigned to nodes, which are equivalent to branches of the regression tree. Ozone time series for the higher concentration nodes are plotted for select sites in Figure 12. By grouping days with similar meteorology, the influence of meteorological variability on the trend in ozone concentrations is partially removed; the remaining trend is presumed to be due to trends in precursor emissions or other non-meteorological influences. Trends over the 13-year period at most sites were found to be declining, with the exception of Detroit which showed fairly flat trends. Comparison of the average of the high concentration node values for 2001-2003 v. 2005-2007 showed an improvement of about 5 ppb across all sites (even Detroit).

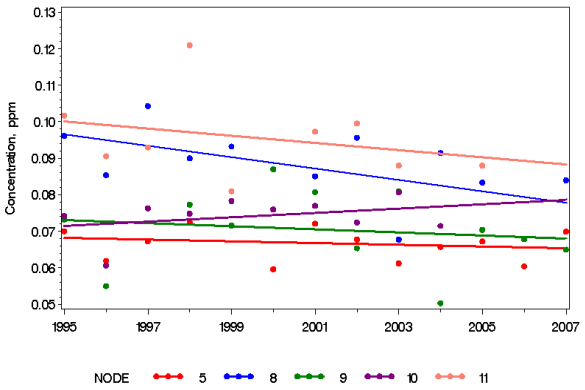
The effect of meteorology was further examined by using an ozone conduciveness index (Kenski, 2008b). This metric reflects the variability from the 13-year average in the number of days in the higher ozone concentration nodes (see Figure 13). Examination of these plots indicates:

- 2002 and 2005 were both above normal, with 2002 tending to be more severe; and
- 2001-2003 and 2005-2007 were both above normal, with no clear pattern in which period was more severe (i.e., ozone conduciveness values were similar at most sites, 2001-2003 values were higher at a few sites, and 2005-2007 values were higher at a few sites).

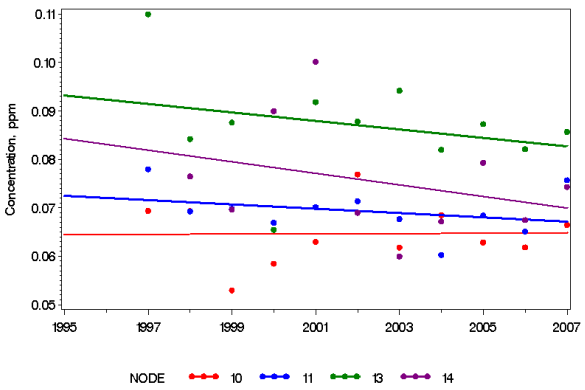
Given the similarity in ozone conduciveness between 2001-2003 and 2005-2007, the improvement in ozone levels noted above is presumed to be due to non-meteorological factors (i.e., emission reductions).

In conclusion, all three statistical approaches (CART and the two nonlinear regression models) show a similar result; ozone in the urban areas of the LADCO region has declined during the 1997-2007 period, even when meteorological variability is accounted for. The decreases are present whether seasonal average ozone, peak values (annual 4th highs), or a subset of high days with similar meteorology are considered. The consistency in results across models is a good indication that these trends reflect impacts of emission control programs.

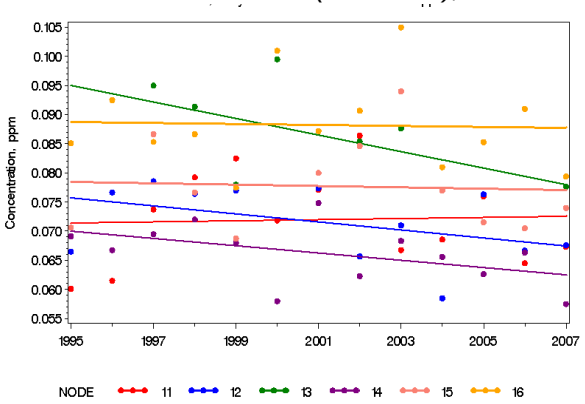
Chiwaukee, WI



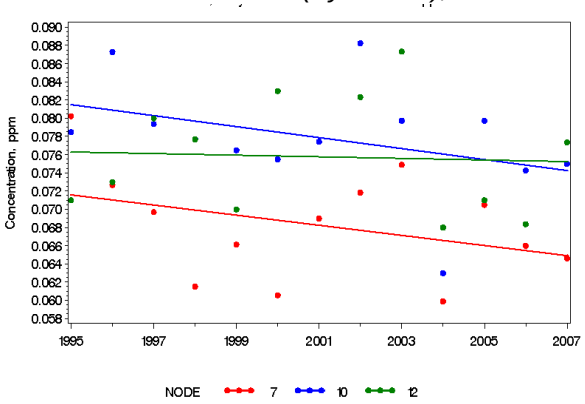
Sheboygan, WI



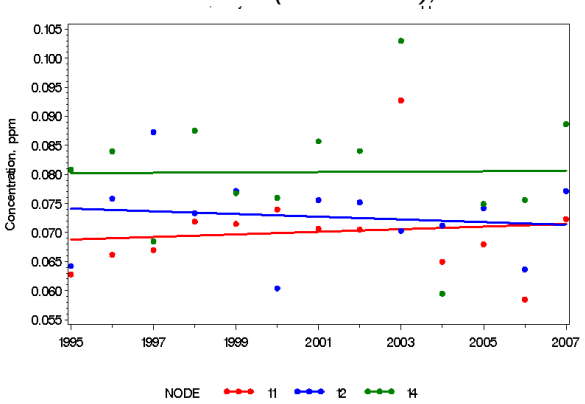
Cleveland (Ashtabula), OH



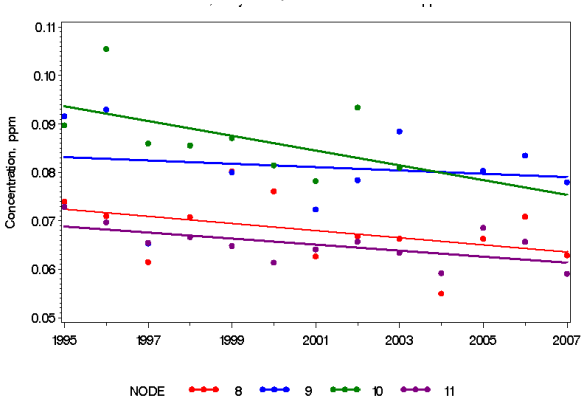
Cincinnati (Sycamore), OH



Detroit (New Haven), MI



St. Louis, MO



Indianapolis, IN

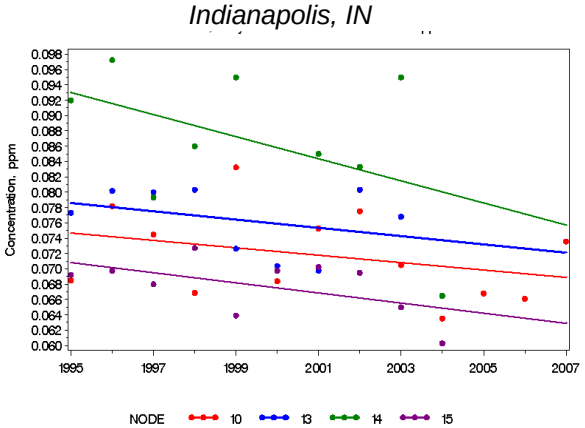


Figure 12. Trends for higher ozone CART groups (average ozone > 65 ppb) for seven Midwestern sites (1995 – 2007)

Note: line represents linear best fit

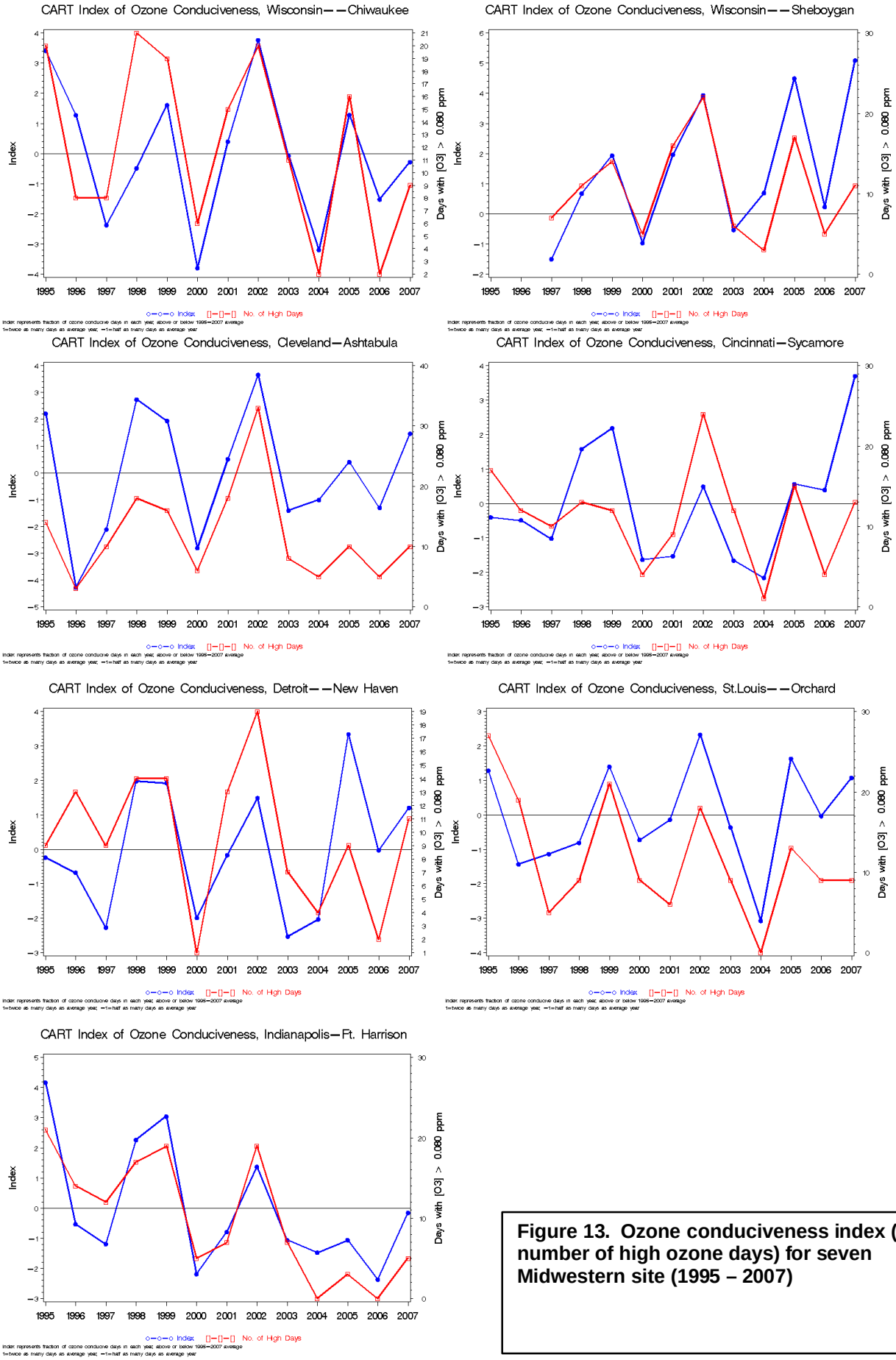


Figure 13. Ozone conduciveness index (and number of high ozone days) for seven Midwestern site (1995 – 2007)

Precursor Sensitivity: Ozone is formed from the reactions of hydrocarbons and nitrogen oxides under meteorological conditions that are conducive to such reactions (i.e., warm temperatures and strong sunlight). In areas with high VOC/NOx ratios, typical of rural environments (with low NOx), ozone tends to be more responsive to reductions in NOx. Conversely, in areas with low VOC/NOx ratios, typical of urban environments (with high NOx), ozone tends to be more responsive to VOC reductions.

An analysis of VOC and NO_x-limitation was conducted with the ozone MAPPER program, which is based on the Smog Production (SP) algorithm (Blanchard, et al., 2003). The "Extent of Reaction" parameter in the SP algorithm provides an indication of VOC and NOx sensitivity:

Extent Range	**Precursor Sensitivity**
< 0.6	VOC-sensitive
0.6 – 0.8	Transitional
> 0.8	NOx-sensitive

A map of the Extent of Reaction values for high ozone days is provided in Figure 14. As can be seen, ozone is usually VOC-limited in cities and NOx-limited in rural areas. (Data from aircraft measurements suggest that ozone is usually NO_x-limited over Lake Michigan and away from urban centers on days when ozone in the urban centers is VOC-limited.) The highest ozone days were found to be NO_x-limited. This analysis suggests that a NOx reduction strategy would be effective in reducing ozone levels. Examination of day-of-week concentrations, however, raises some question about the effectiveness of NOx reductions.

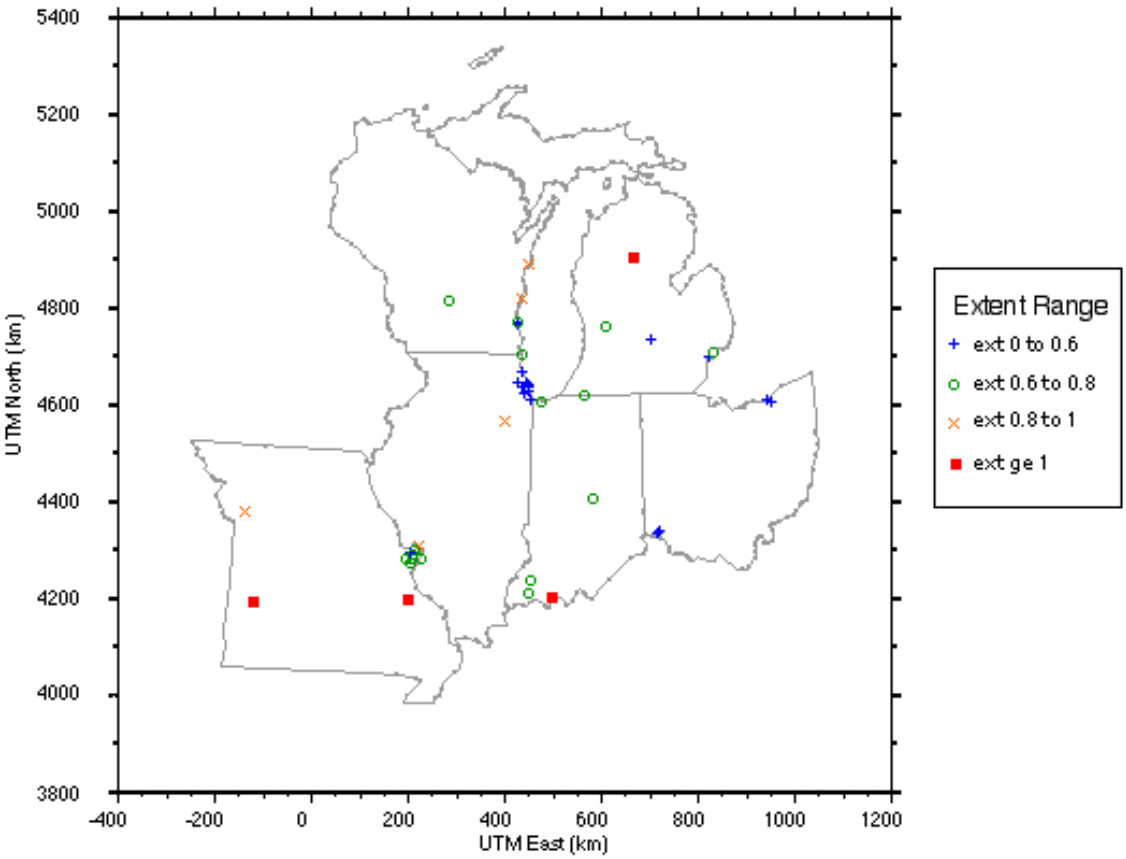


Figure 14. Mean afternoon extent of reaction (1998 – 2002)

Blanchard (2004 and 2005a) examined weekend-weekday differences in ozone and NO_x in the Midwest. All urban areas in these two studies exhibited substantially lower (40-60%) weekend concentrations of NO_x compared to weekday concentrations. Despite lower weekend NO_x concentrations, weekend ozone concentrations were not lower; in fact, most urban sites had higher concentrations of ozone, although the increase was generally not statistically significant (see Figure 15). This small but counterproductive change in **local** ozone concentrations suggests that **local** urban-scale NO_x reductions alone may not be very effective.

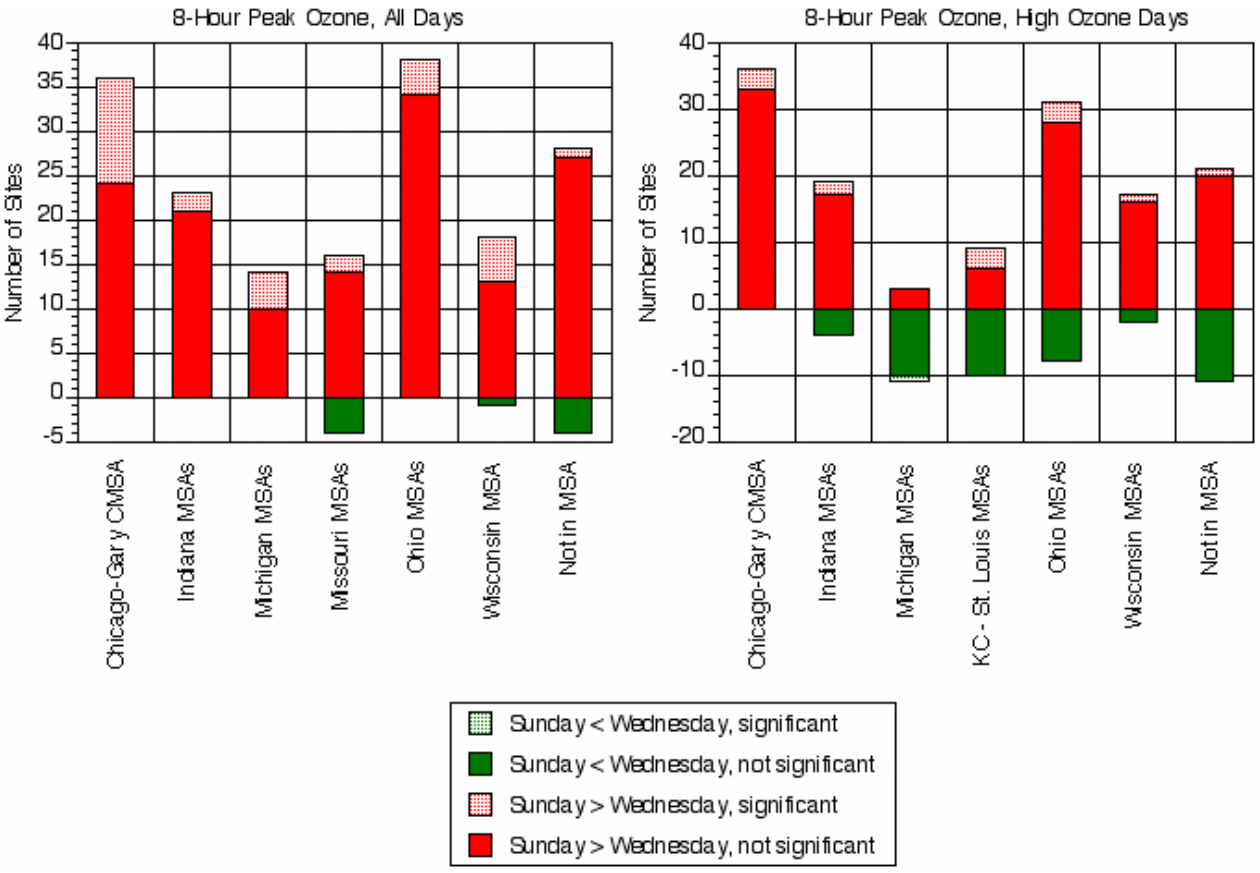


Figure 15. Weekday/weekend differences in 8-hour ozone – number of sites with weekend increase (positive values) v. number of sites with weekend decreases (negative values)

Two additional analyses, however, demonstrate the positive effect of NOx emission reductions on downwind ozone concentrations. First, Blanchard (2005a) looked at the effect of changes in precursor emissions in Chicago on downwind ozone levels in western Michigan. For the transport days of interest (i.e., southwesterly flow during the summers of 1999 – 2002), mean NOx concentrations in Chicago are about 50% lower and mean ozone concentrations at the (downwind) western Michigan sites are about 1.5 – 5.2 ppb (3 – 8 %) lower on Sunday compared to Wednesday. This degree of change in downwind ozone levels suggests a positive, albeit non-linear response to urban area emission reductions.

Second, Environ (2007a) examined the effect of differences in day-of-week emissions in southeastern Michigan on downwind ozone levels. This modeling study found that weekend changes in ozone precursor emissions cause both increases and decreases in Southeast Michigan ozone, depending upon location and time:

- Weekend increases in 8-hour maximum ozone occur in and immediately downwind of the Detroit urban area (i.e., in VOC-sensitive areas).
- Weekend decreases in 8-hour maximum ozone occur outside and downwind of the Detroit urban area (i.e., in NOx-sensitive areas).
- At the location of the peak 8-hour ozone downwind of Detroit, ozone was lower on weekends than weekdays.
- Ozone benefits (reductions) due to weekend emission changes in Southeast Michigan can be transported downwind for hundreds of miles.
- Southeast Michigan benefits from lower ozone transported into the region on Saturday through Monday because of weekend emission changes in upwind areas.

In summary, these analyses suggest that urban VOC reductions and regional (urban and rural) NOx reductions will be effective in lowering ozone concentrations. Local NOx reductions can lead to local ozone increases (i.e., NOx disbenefits), but this effect does not appear to pose a problem with respect to attainment of the standard. It should also be noted that urban VOC and regional NOx reductions are likely to have multi-pollutant benefits (e.g., both lower ozone and $PM_{2.5}$ impacts).

2.2 $PM_{2.5}$

In 1997, EPA adopted the $PM_{2.5}$ standards of 15 ug/m^3 (annual average) and 65 ug/m3 (24-hour average). The annual standard is attained if the 3-year average of the annual average $PM_{2.5}$ concentration is less than or equal to the level of the standard. The daily standard is attained if the 98th percentile of 24-hour $PM_{2.5}$ concentrations in a year, averaged over three years, is less than or equal to the level of the standard.

In 2006, EPA revised the $PM_{2.5}$ standards to 15 ug/m^3 (annual average) and 35 ug/m^3 (24-hour average).

Current Conditions: Maps of annual and 24-hour $PM_{2.5}$ design values for the 3-year period 2005-2007 are shown in Figure 16. The "hotter" colors represent higher concentrations, where red dots represent sites with design values above the annual standard. Currently, there are 30 sites in violation of the annual $PM_{2.5}$ standard.

Table 2 provides the annual $PM_{2.5}$ concentrations and associated design values since 2003 for several high monitoring sites throughout the region.

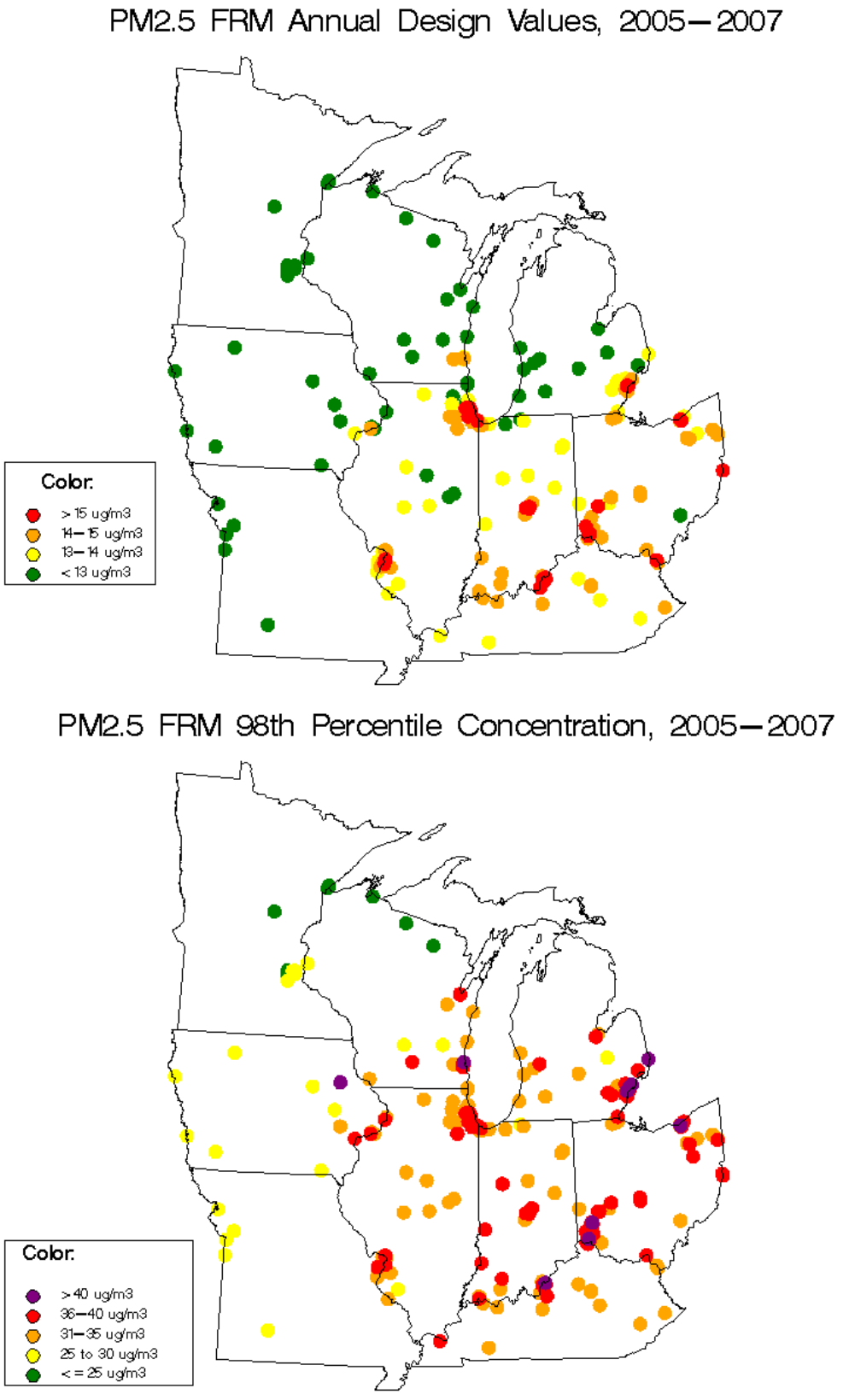


Figure 16. $PM_{2.5}$ design values - annual average (top) and 24-hour average (bottom) (2005-2007)

Table 2. PM2.5 Data for Select Sites in 5-State Region

			Annual Average Conc.					Design Values			2005 BY	2002 BY
Key Site	**County**	**Site ID**	**'03**	**'04**	**'05**	**'06**	**'07**	**'03 - '05**	**'04 - '06**	**'05 - '07**	**Average w/ 2007**	**Average**
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	**15.0**	**15.6**
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**	
Indy - Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**
Indy - W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**	
Indy - Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.0	15.3	17.0	16.2	16.2	**16.5**	**16.7**
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.4	13.6	14.7	15.4	14.9	14.9	**15.1**	**16.0**
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	15.9	**16.2**	**16.3**
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.4	**15.2**	**15.7**
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**

When EPA initially set the 24-hour standard at 65 µg/m^3, it also adopted the following concentration ranges for its Air Quality Index (AQI) scale:

Good	< 15 ug/m^3
Moderate	15-40 µg/m^3
Unhealthy for Sensitive Groups (USG)	40-65 µg/m^3
Unhealthy	65-150 µg/m^3

Figure 17 shows the frequency of these AQI categories for major metropolitan areas in the region. Daily average concentrations are often in the moderate range and occasionally in the USG range. Moderate and USG levels can occur any time of the year.

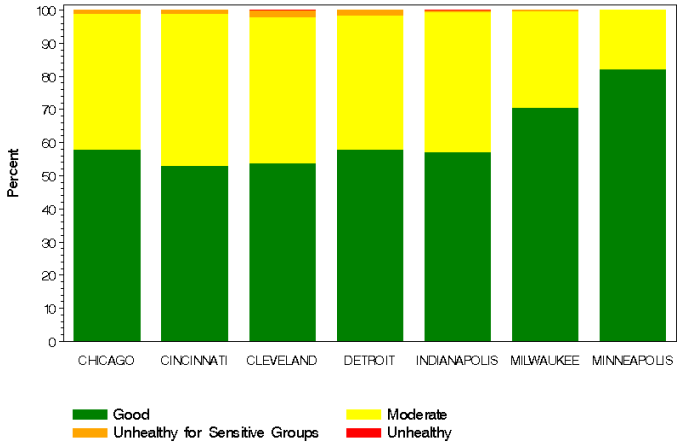


Figure 17. Percent of days in AQI categories for $PM_{2.5}$ (2002-2004)

Data Variability: $PM_{2.5}$ concentrations vary spatially, temporally, and chemically in the region. This variability is discussed further below.

On an annual basis, $PM_{2.5}$ exhibits a distinct and consistent spatial pattern. As seen in Figure 16, across the Midwest, annual concentrations follow a gradient from low values (5-6 µg/m^3) in northern and western areas (Minnesota and northern Wisconsin) to high values (17-18 µg/m^3) in Ohio and along the Ohio River. In addition, concentrations in urban areas are higher than in upwind rural areas, indicating that local urban sources add a significant increment of 2-3 µg/m^3 to the regional background of 12 - 14 µg/m^3 (see Figure 18).

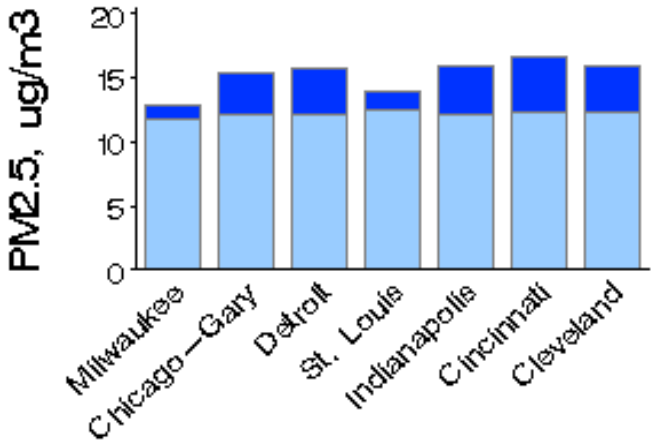


Figure 18. Regional (lighter shading) v. local components (darker shading) of annual average $PM_{2.5}$ concentrations

Because monitoring for $PM_{2.5}$ only began in earnest in 1999, after promulgation of the $PM_{2.5}$ standard, limited data are available to assess trends. Time series based on federal reference method (FRM) $PM_{2.5}$-mass data show a downward trend in each state (see Figure 19)[7].

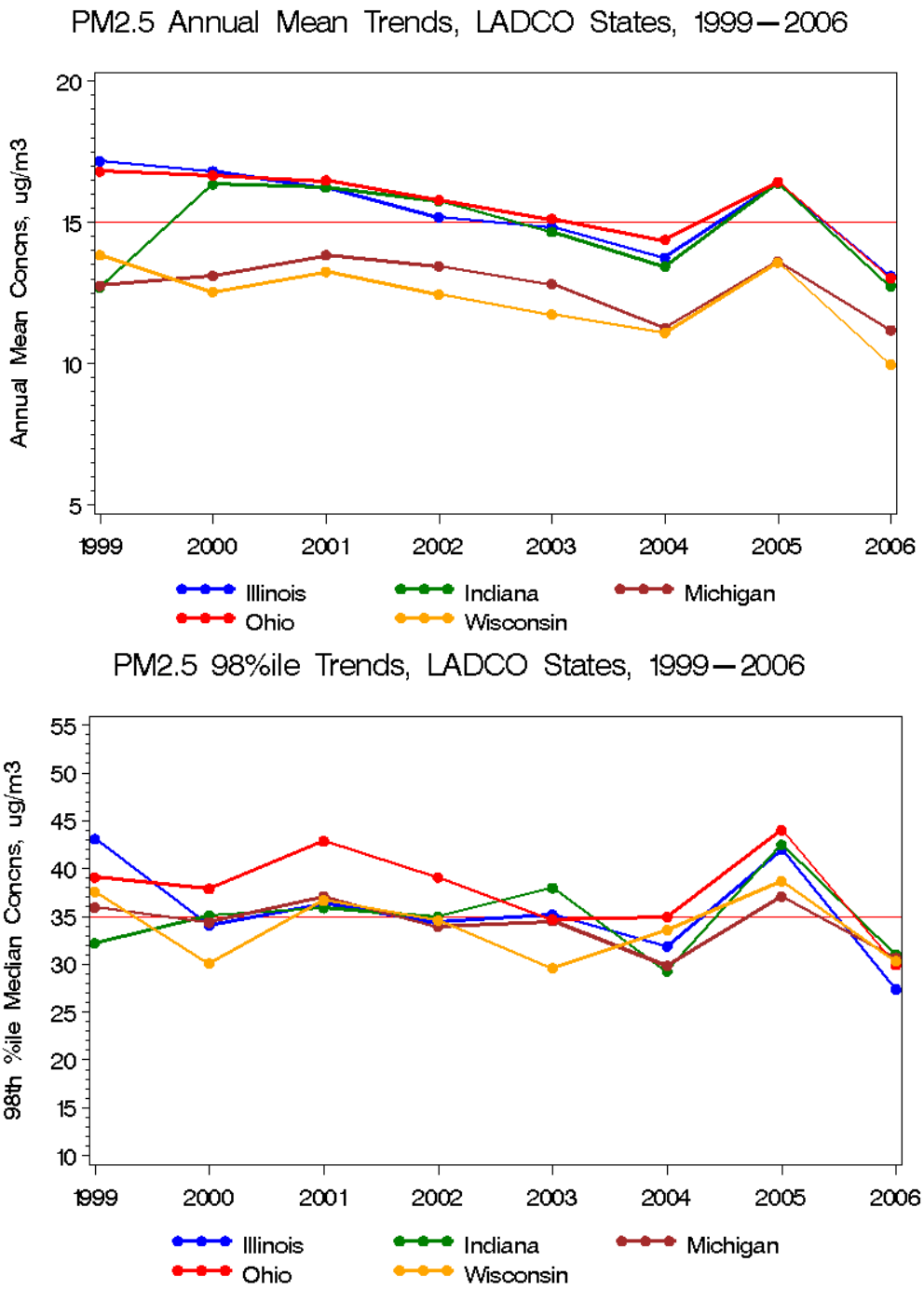


Figure 19. $PM_{2.5}$ trends in annual average (top) and daily concentrations (bottom)

[7] Despite the general downward trend since 1999, all states experienced an increase during 2005. Further analyses are underway to understand this increase (e.g., examination of meteorological and emissions effects).

A statistical analysis of $PM_{2.5}$ trends was performed using the nonparametric Theil test for slope (Hollander and Wolfe, 1973). Trends were generally consistent around the region, for both PM mass and for the individual components of mass. Figure 20 shows trends for $PM_{2.5}$ based on FRM data at sites with six or more years of data since 1999. The size and direction of each arrow shows the size and direction of the trend for each site; solid arrows show statistically significant trends and open arrows show trends that are not significant. Region-wide decreases are widespread and consistent; all sites had decreasing concentration trends (13 of the 38 were statistically significant). The average decrease for this set of sites is -0.24 ug/m^3/year.

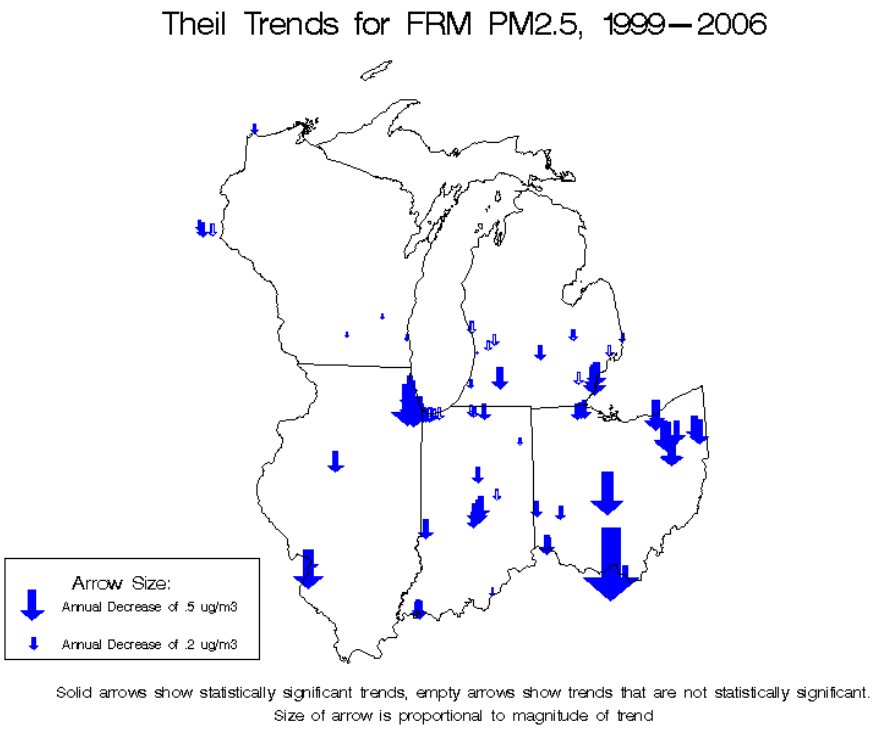


Figure 20. Annual trends in $PM_{2.5}$ mass (1999 – 2006)

Seasonal trends show mostly similar patterns (Figure 21). Trends were downward at most sites and seasons, with overall seasonal averages varying between -0.15 to -0.56 ug/m^3/year. The strongest and most significant decreases took place during the winter quarter (January - March). No statistically significant increasing trends were observed.

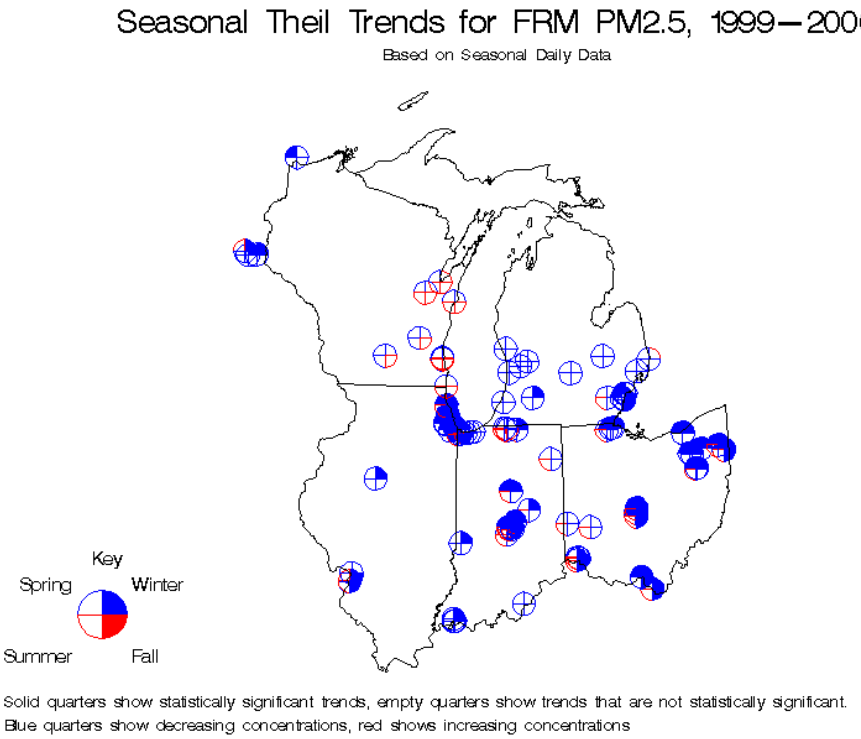


Figure 21. Seasonal trends in $PM_{2.5}$ mass (1999 – 2006)

$PM_{2.5}$ shows a slight variation from weekday to weekend, as seen in Figure 22. Although most cities have slightly lower concentrations on the weekend, the difference is usually less than 1 $\mu g/m^3$. There is a more pronounced weekday/weekend difference at monitoring sites that are strongly source-influenced. Rural monitors tend to show less of a weekday/weekend pattern than urban monitors.

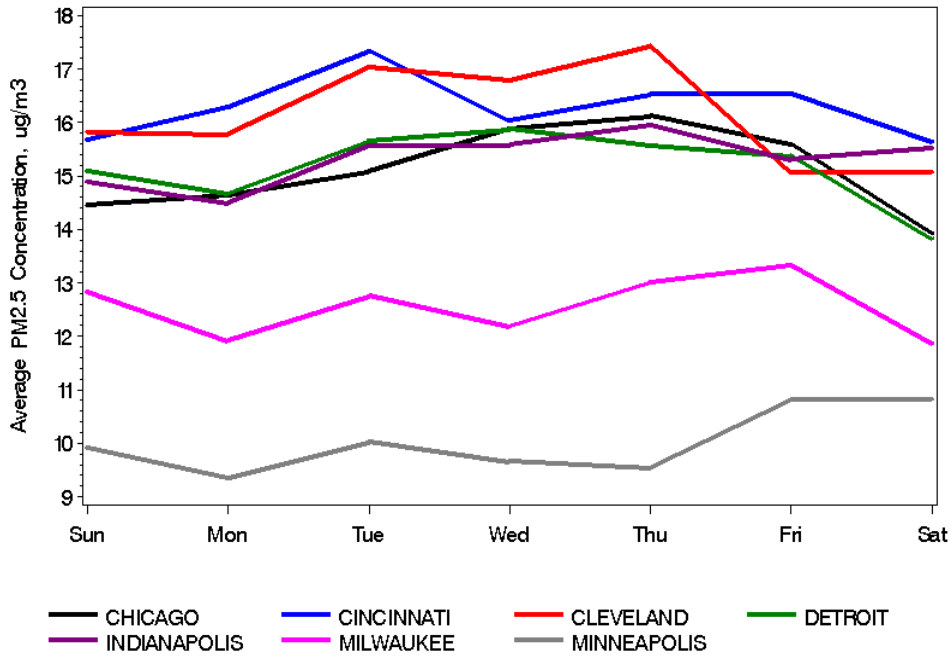


Figure 22 Day-of-week variability in $PM_{2.5}$ (2002-2004)

In the Midwest, $PM_{2.5}$ is made up of mostly ammonium sulfate, ammonium nitrate, and organic carbon in approximately equal proportions on an annual average basis. Elemental carbon and crustal matter (also referred to as soil) contribute less than 5% each.

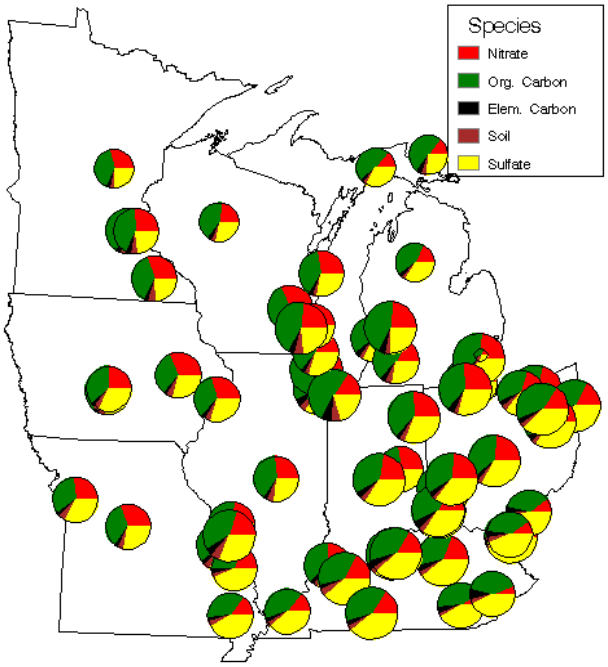


Figure 23. Spatial map of $PM_{2.5}$ chemical composition in the Midwest (2002-2003)

The three major components vary spatially (Figure 23), including notable urban and rural differences (Figure 24). The components also vary seasonally (Figure 25). These patterns account for much of the annual variability in $PM_{2.5}$ mass noted above.

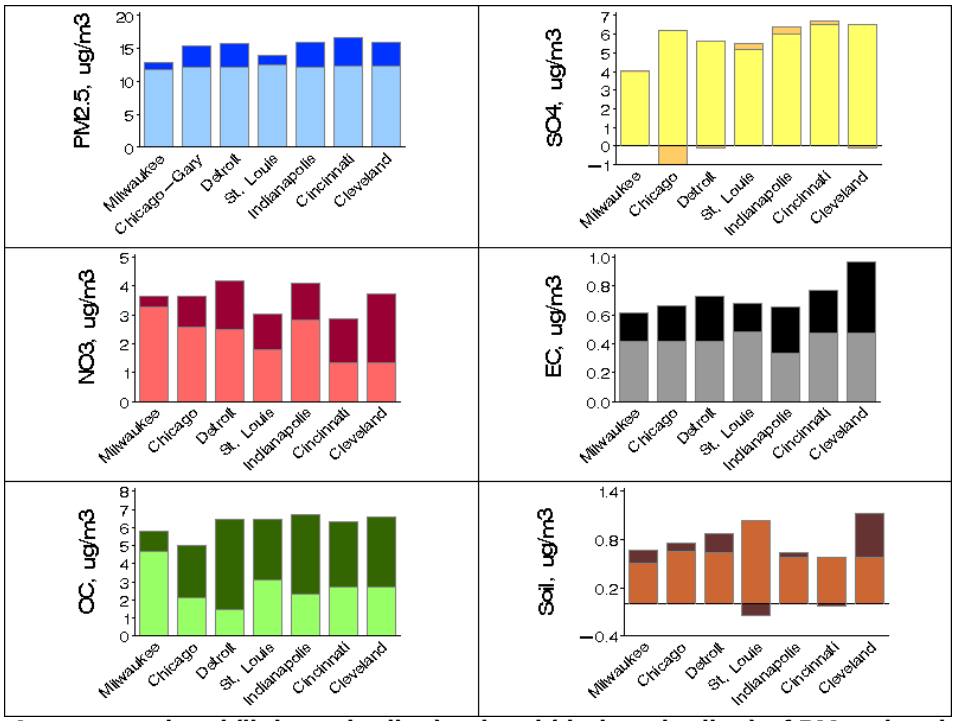


Figure 24. Average regional (lighter shading) v. local (darker shading) of $PM_{2.5}$ chemical species

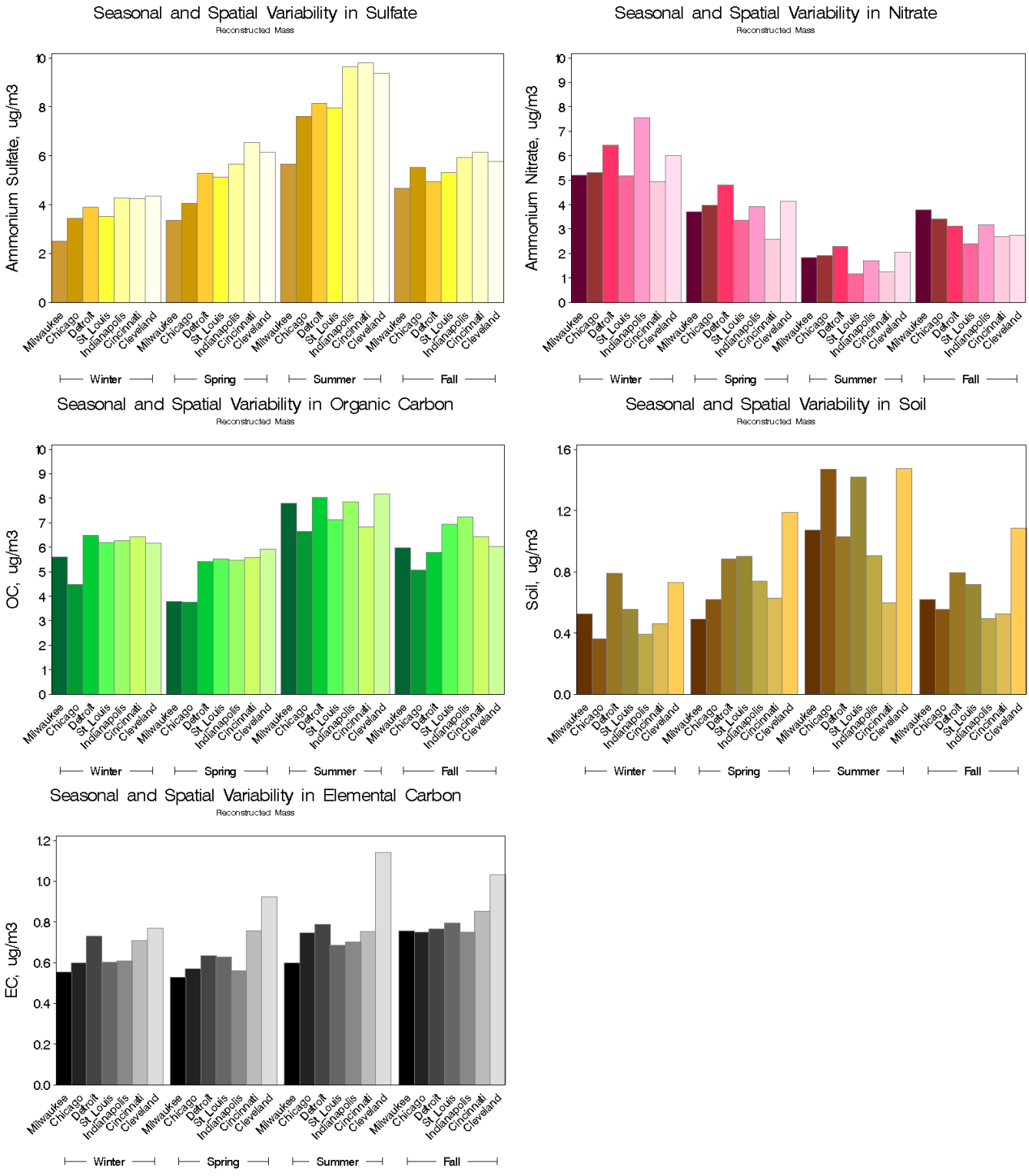


Figure 25 Seasonal and spatial variability in $PM_{2.5}$ components

Ammonium sulfate peaks in the summer and is highest in the southern and eastern parts of the Midwest, closest to the Ohio River Valley. Sulfate is primarily a regional pollutant; concentrations are similar in rural and urban areas and highly correlated over large distances. It is formed when sulfuric acid (an oxidation product of sulfur dioxide) and ammonia react in the atmosphere, especially in cloud droplets. Coal combustion is the primary source of sulfur dioxide; ammonia is emitted primarily from animal husbandry operations and fertilizer use.

Ammonium nitrate has almost the opposite spatial and seasonal pattern, with the highest concentrations occurring in the winter and in the northern parts of the region. Nitrate seems to have both regional and local sources, because urban concentrations are higher than rural upwind concentrations. Ammonium nitrate forms when nitric acid reacts with ammonia, a process that is enhanced when temperatures are low and humidity is high. Nitric acid is a product of the oxidation of nitric oxide, a pollutant that is emitted by combustion processes.

Organic carbon is more consistent from season to season and city to city, although concentrations are generally slightly higher in the summer. Like nitrate, organic carbon has both regional and local components. Particulate organic carbon can be emitted directly from cars and other fuel combustion sources or formed in a secondary process as volatile organic gases react and condense. In rural areas, summer organic carbon has significant contributions from biogenic sources.

Precursor Sensitivity: Data from the Midwest ammonia monitoring network were analyzed with thermodynamic equilibrium models to assess the effect of changes in precursor gas concentrations on $PM_{2.5}$ concentrations (Blanchard, 2005b). These analyses indicate that particle formation responds in varying degrees to reductions in sulfate, nitric acid, and ammonia. Based on Figure 26, which shows $PM_{2.5}$ concentrations as a function of sulfate, nitric acid (HNO3), and ammonia (NH3), several key findings should be noted:

- $PM_{2.5}$ mass is sensitive to reductions in sulfate at all times of the year and all parts of the region. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases.

- $PM_{2.5}$ mass is also sensitive to reductions in nitric acid and ammonia. The greatest $PM_{2.5}$ decrease in response to nitric acid reductions occurs during the winter, when nitrate is a significant fraction of $PM_{2.5}$.

- Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

- Ammonia becomes more limiting as one moves from west to east across the region.

Examination of weekend/weekday difference in PM-nitrate and NOx concentrations in the Midwest demonstrate that reductions in local (urban) NOx lead to reductions, albeit non-proportional reductions, in PM-nitrate (Blanchard, 2004). This result is consistent with analyses of continuous PM-nitrate from several US cities, including St. Louis (Millstein, et al, 2007).

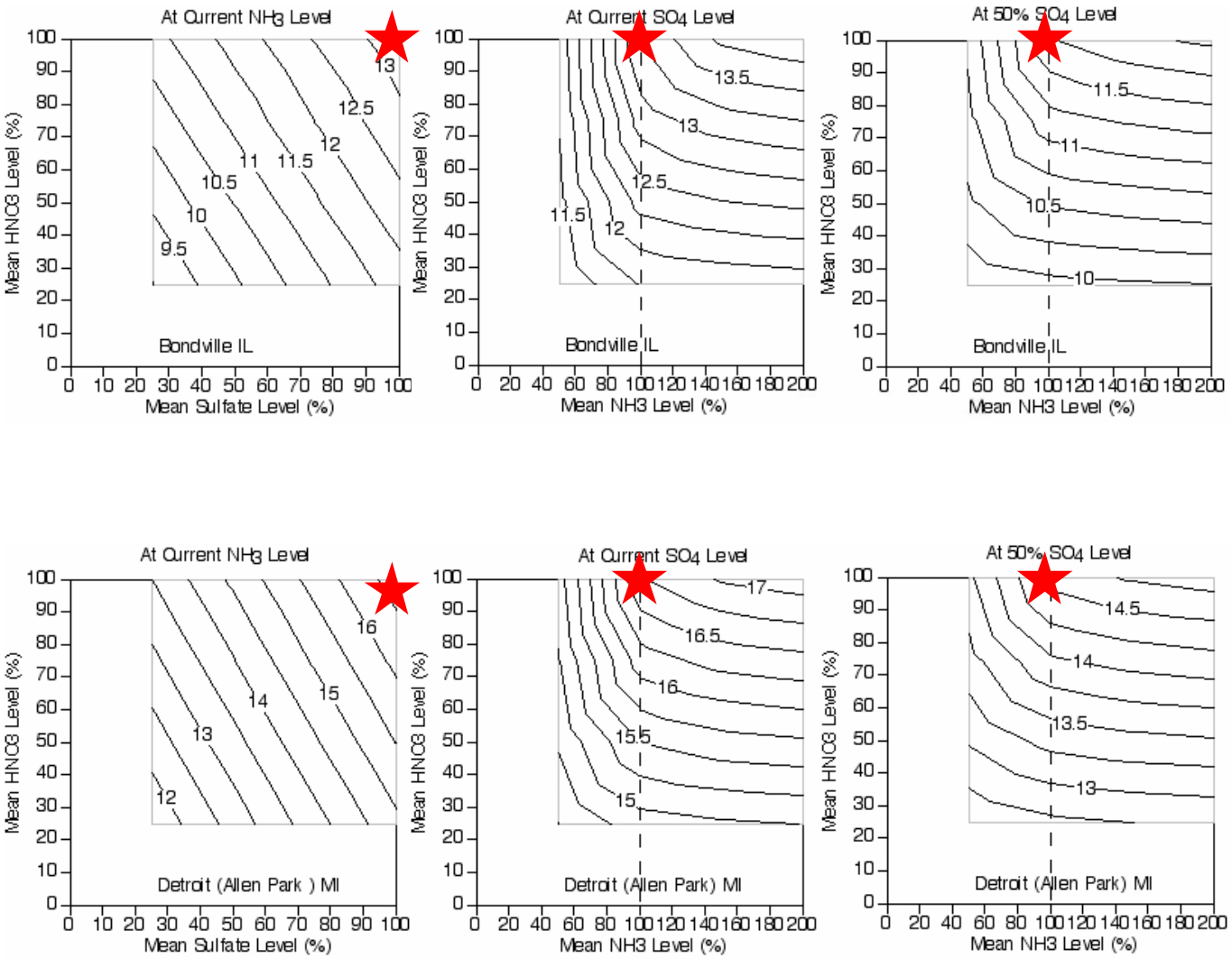


Figure 26. Predicted mean PM fine mass concentrations at Bondville, IL (top) and Detroit (Allen Park), MI (bottom) as functions of changes in sulfate, nitric acid (HNO3), and ammonia (NH3)

Note: starting at the baseline values (represented by the red star), either moving downward (reductions in nitric acid) or moving leftward (reductions in sulfate or ammonia) results in lower $PM_{2.5}$ values

Meteorology: $PM_{2.5}$ concentrations are not as strongly influenced by meteorology as ozone, but the two pollutants share some similar meteorological dependencies. In the summer, conditions that are conducive to ozone (hot temperatures, stagnant air masses, and low wind speeds due to stationary high pressure systems) also frequently give rise to high $PM_{2.5}$. In the case of PM, the reason is two-fold: (1) stagnation and limited mixing under these conditions cause $PM_{2.5}$ to build up, usually over several days, and (2) these conditions generally promote higher conversion of important precursors (SO_2 to SO_4) and higher emissions of some precursors, especially biogenic carbon. Wind direction is another strong determinant of $PM_{2.5}$; air transported from polluted source regions has higher concentrations.

Unlike ozone, $PM_{2.5}$ has occasional winter episodes. Conditions are similar to those for summer episodes, in that stationary high pressure and (seasonally) warm temperatures are usually factors. Winter episodes are also fueled by high humidity and low mixing heights.

$PM_{2.5}$ chemical species show noticeable transport influences. Trajectory analyses have demonstrated that high PM-sulfate is associated with air masses that traveled through the sulfate-rich Ohio River Valley (Poirot, et al, 2002 and Kenski, 2004). Likewise, high PM-nitrate is associated with air masses that traveled through the ammonia-rich Midwest. Figure 27 shows results from an ensemble trajectory analysis of 17 rural eastern IMPROVE sites.

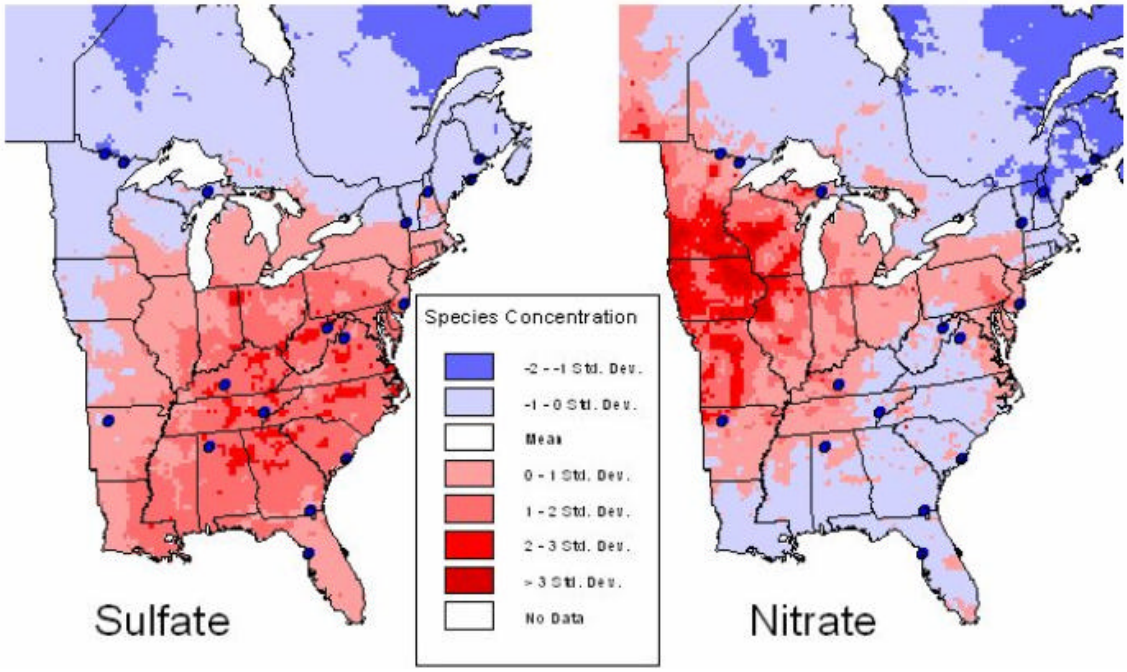


Figure 27. Sulfate and nitrate source regions based on ensemble trajectory analysis

When these results are considered together with analyses of precursor sensitivity (e.g., Figure 26), one possible conclusion is that ammonia control in the Midwest could be effective at reducing nitrate concentrations. The thermodynamic equilibrium modeling shows that ammonia reductions would reduce PM concentrations in the Midwest, but that nitric acid reductions are more effective when the probable reductions in future sulfate levels are considered.

Source Culpability: Three source apportionment studies were performed using speciated $PM_{2.5}$ monitoring data and statistical analysis methods (Hopke, 2005, STI, 2006, and STI, 2008). Figure 28 summarizes the source contributions from these studies. The studies show that a large portion of $PM_{2.5}$ mass consists of secondary, regional impacts, which cannot be attributed to individual facilities or sources (e.g., secondary sulfate, secondary nitrate, and secondary organic aerosols). Nevertheless, wind analyses (e.g., Figure 27) provide information on likely source regions. Regional- or national-scale control programs may be the most effective way to deal with these impacts. EPA's CAIR, for example, will provide for substantial reductions in SO2 emissions over the eastern half of the U.S., which will reduce sulfate (and $PM_{2.5}$) concentrations and improve visibility levels.

The studies also show that a smaller, yet significant portion of $PM_{2.5}$ mass is due to emissions from nearby (local) sources. Local (urban) excesses occur in many urban areas for organic and elemental carbon, crustal matter, and, in some cases, sulfate. The statistical analysis methods help to identify local sources and quantify their impact. This information is valuable to states wishing to develop control programs to address local impacts. A combination of national/regional-scale and local-scale emission reductions may be necessary to provide for attainment.

The carbon sources are not easily identified in complex urban environments. LADCO's Urban Organics Study (STI, 2006) identified four major sources of organic carbon: mobile sources, burning, industrial sources, and secondary organic aerosols. Additional sampling and analysis is underway in Cleveland and Detroit to provide further information on sources of organic carbon.

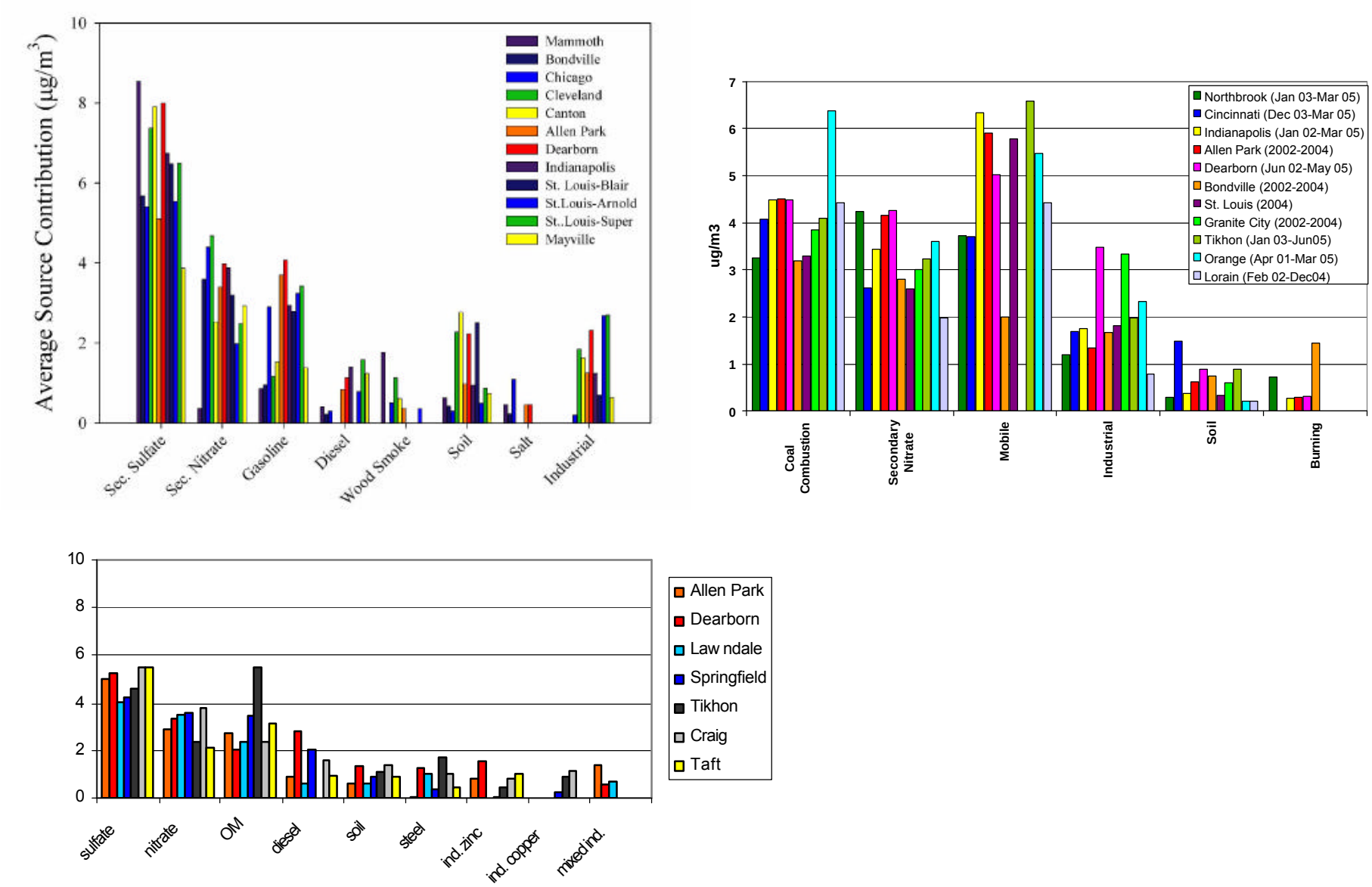


Figure 28. Major Source Contributions in the Midwest based on Hopke, 2005 (upper left), STI, 2006 (upper right), and STI, 2008 (lower left) (Note: the labeling of similar source types varies between studies – e.g., organic carbon/mobile sources are named gasoline and diesel by Hopke, mobile by STI 2006, and OM and diesel by STI 2008)

2.3 Haze

Section 169A of the Clean Air Act sets as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution". To implement this provision, in 1999, EPA adopted regulations to address regional haze visibility impairment (USEPA, 1999). EPA's rule requires states to "make reasonable progress toward meeting the national goal". Specifically, states must establish reasonable progress goals, which provide for improved visibility on the most impaired (20% worst) days sufficient to achieve natural conditions by the year 2064, and for no degradation on the least impaired (20% best) days.

The primary cause of impaired visibility in the Class I areas is pollution by fine particles that scatter light. The degree of impairment, which is expressed in terms of visual range, light extinction (1/Mm), or deciviews (dv), depends not just on the total $PM_{2.5}$ mass concentration, but also on the chemical composition of the particles and meteorological conditions.

Current Conditions: A map of the average light extinction values for the most impaired (20% worst) visibility days for the 5-year baseline period (2000-2004) is shown in Figure 29.

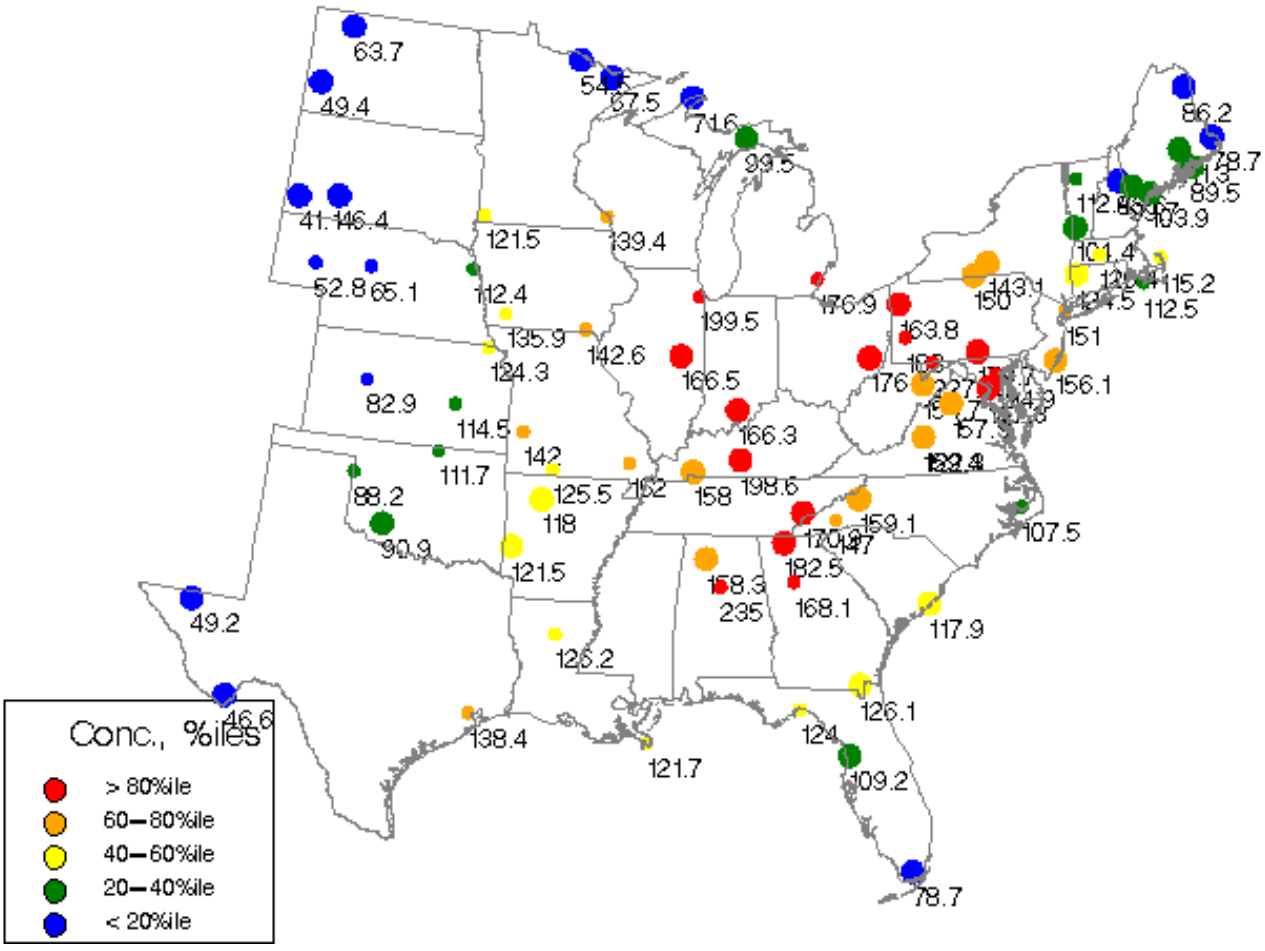


Figure 29. Baseline Visibility Levels for 20% Worst Days (2000 – 2004), units: Mm^{-1}

Initially, the baseline (2000 – 2004) visibility condition values were derived using the average for the 20% worst and 20% best days for each year, as reported on the VIEWS website: http://vista.cira.colostate.edu/views/Web/IMPROVE/SummaryData.aspx . These values were calculated using the original IMPROVE equation for reconstructed light extinction.

Three changes were made to the baseline calculations to produce a new set of values. First, the reconstructed light extinction equation was revised by the IMPROVE Steering Committee in 2005. The new IMPROVE equation was used to calculate updated baseline values.

Second, due to sampler problems, the 2002-2004 data for Boundary Waters were invalid for certain chemical species. (Note, sulfate and nitrate data were valid.) A "substituted" data set was developed by using values from Voyageurs for the invalid species.

Third, LADCO identified a number of days during 2000-2004 where data capture at the Class I monitors was incomplete (Kenski, 2007b). The missing data cause these days to be excluded from the baseline calculations. However, the light extinction due to the remaining measured species is significant (i.e., above the 80th percentile). It makes sense to include these days in the baseline calculations, because they are largely dominated by anthropogenic sources. (Only one of these days is driven by high organic carbon, which might indicate non-anthropogenic aerosol from wildfires.) As seen in Table 3, inclusion of these days in the baseline calculation results in a small, but measurable, effect on the baseline values (i.e., values increase from 0.2 to 0.8 dv).

Table 3. Average of 20% worst days, with and without missing data days

	Average Worst Day DV, per RHR	Average Worst Day DV, with Missing Data Days	Difference
BOWA	19.59	19.86	0.27
ISLE	20.74	21.59	0.85
SENE	24.16	24.38	0.22
VOYA	19.27	19.48	0.21

A summary of the initial and updated baseline values for the Class I areas in northern Michigan and northern Minnesota are presented in Table 4. The updated baseline values reflect the most current, complete understanding of visibility impairing effects and, as such, will be used for SIP planning purposes.

Table 4. Summary of visibility metrics (deciviews) for northern Class I areas

Old IMPROVE Equation (Cite: VIEWS, November 2005)									
		20% Worst Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**	**2018 URI Value**	**Natural Conditions**
Voyageurs		18.50	18.00	19.00	19.20	17.60	18.46	16.74	11.09
BWCA		19.85	19.99	19.68	19.73	17.65	19.38	17.47	11.21
Isle Royale		20.00	22.00	20.80	19.50	19.10	20.28	18.17	11.22
Seney		22.60	24.90	24.00	23.80	22.60	23.58	20.73	11.37
		20% Best Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**		**Natural Conditions**
Voyageurs		6.30	6.20	6.70	7.00	5.40	6.32		3.41
BWCA		5.90	6.52	6.93	6.67	5.61	6.33		3.53
Isle Royale		5.70	6.40	6.40	6.30	5.30	6.02		3.54
Seney		5.80	6.10	7.30	7.50	5.80	6.50		3.69
New IMPROVE Equation (Cite: VIEWS, March 2006)									
		20% Worst Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**	**2018 URI Value**	**Natural Conditions**
Voyageurs		19.55	18.57	20.14	20.25	18.87	19.48	17.74	12.05
BWCA		20.20	20.04	20.76	20.13	18.18	19.86	17.94	11.61
Isle Royale		20.53	23.07	21.97	22.35	20.02	21.59	19.43	12.36
Seney		22.94	25.91	25.38	24.48	23.15	24.37	21.64	12.65
		20% Best Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**		**Natural Conditions**
Voyageurs		7.01	7.12	7.53	7.68	6.37	7.14		4.26
BWCA		6.00	6.92	7.00	6.45	5.77	6.43		3.42
Isle Royale		6.49	7.16	7.07	6.99	6.12	6.77		3.72
Seney		6.50	6.78	7.82	8.01	6.58	7.14		3.73

Notes: (1) BWCA values for 2002 - 2004 reflect "substituted" data.
(2) New IMPROVE equation values include Kenski, 2007 adjustment for missing days

URI = uniform rate of improvement

As noted above, the goal of the visibility program is to achieve natural conditions. Initially, the natural conditions values for each Class I area were taken directly from EPA guidance (EPA, 2003). These values were calculated using the original IMPROVE equation. This equation was revised by the IMPROVE Steering Committee in 2005, and the new IMPROVE equation was used to calculate updated natural conditions values. The updated values are reported on the VIEWS website.

A summary of the initial and updated natural conditions values are presented in Table 4. The updated natural conditions values (based on the new IMPROVE equation) will be used for SIP planning purposes.

Data Variability: For the four northern Class I areas, the most important $PM_{2.5}$ chemical species are ammonium sulfate, ammonium nitrate, and organic carbon. The contribution of these species on the 20% best and 20% worst visibility days (based on 2000 – 2004 data) is provided in Figure 30. For the 20% worst visibility days, the contributions are: sulfate = 35-55%, nitrate = 25-30%, and organic carbon = 12-22%. Although the chemical composition is similar, sulfate increases in importance from west to east and concentrations are highest at Seney (the easternmost site). It should also be noted that sulfate and nitrate contribute more to light extinction than to $PM_{2.5}$ mass because of their hygroscopic properties.

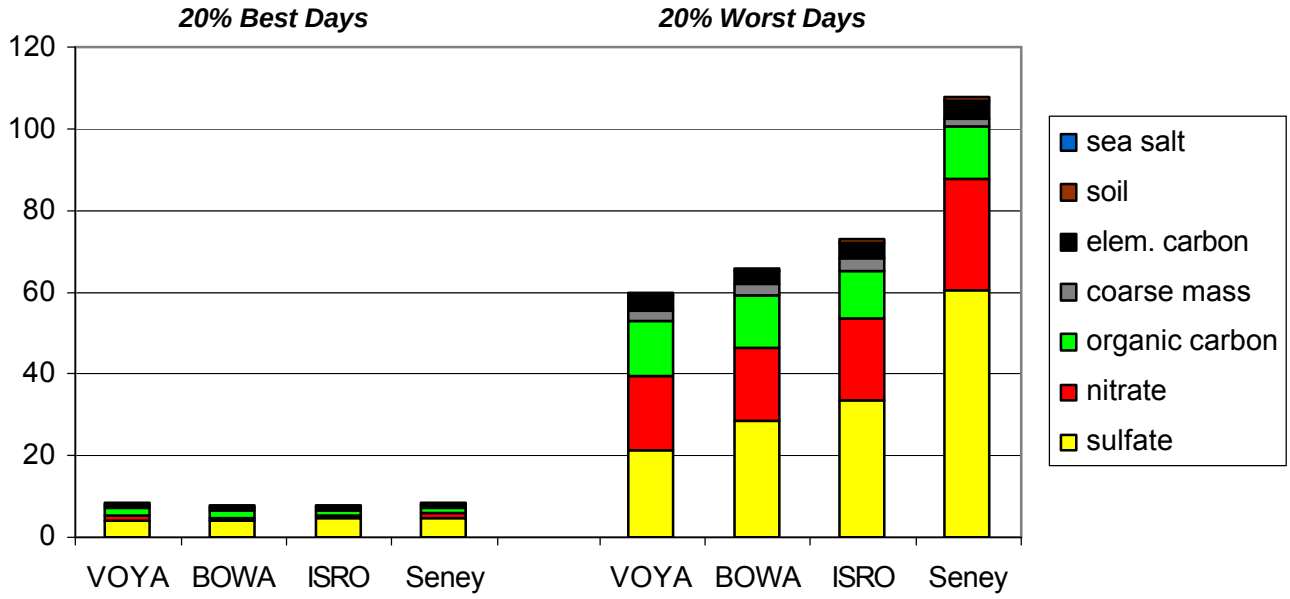


Figure 30. Chemical composition of light extinction for 20% best visibility days (left) and 20% worst visibility days (right) in terms of Mm^{-1}

Analysis of $PM_{2.5}$ mass and chemical species for rural IMPROVE (and IMPROVE-protocol) sites in the eastern U.S. showed a high degree of correlation between $PM_{2.5}$-mass, sulfate, and nitrate levels (see Figure 31). The Class I sites in northern Michigan and northern Minnesota, in particular, are highly correlated for $PM_{2.5}$ mass, sulfates, and organic carbon mass (AER, 2004).

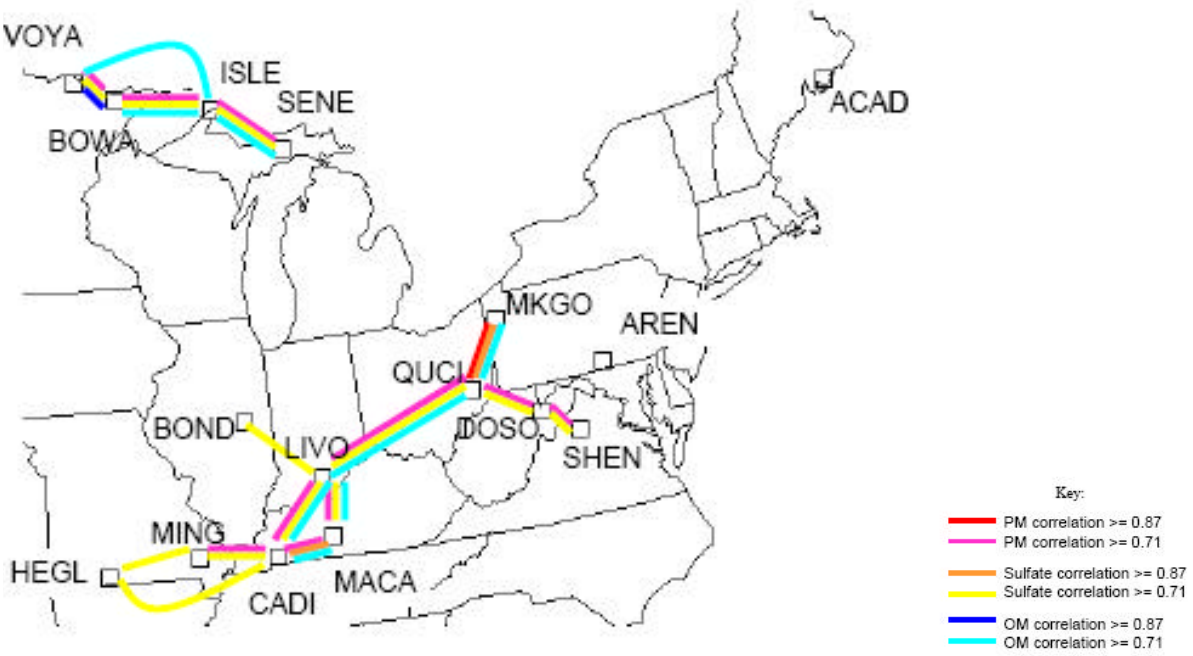


Figure 31. Correlations among IMPROVE (and IMPROVE-protocol) monitoring sites in Eastern U.S.

Long-term trends at Boundary Waters (the only regional site with a sufficient data record) show significant decreases in total $PM_{2.5}$ (-0.005 ug/year) and SO4 (-0.04 ug/year) and an increase in NO3 (+0.01 ug/year). These $PM_{2.5}$ and SO4 trends are generally consistent with long-term trends at other IMPROVE sites in the eastern U.S., which have shown widespread decreases in SO4 and $PM_{2.5}$ (DeBell, et al, 2006). Detecting changes in nitrate has been hampered by uncertainties in the IMPROVE data for particular years and, thus, this estimate should be considered tentative.

Haze in the Midwest Class I areas has no strong seasonal pattern. Poor visibility days occur throughout the year, as indicated in Figure 32. (Note, in contrast, other parts of the country, such as Shenandoah National Park in Virginia, show a strong tendency for the worst air quality days to occur in the summer months.) This figure and Figure 33 (which presents the monthly average light extinction values based on all sampling days) also show that sulfate and organic carbon concentrations are higher in the summer, and nitrate concentrations are higher in the winter, suggesting the importance of different sources and meteorological conditions at different times of the year.

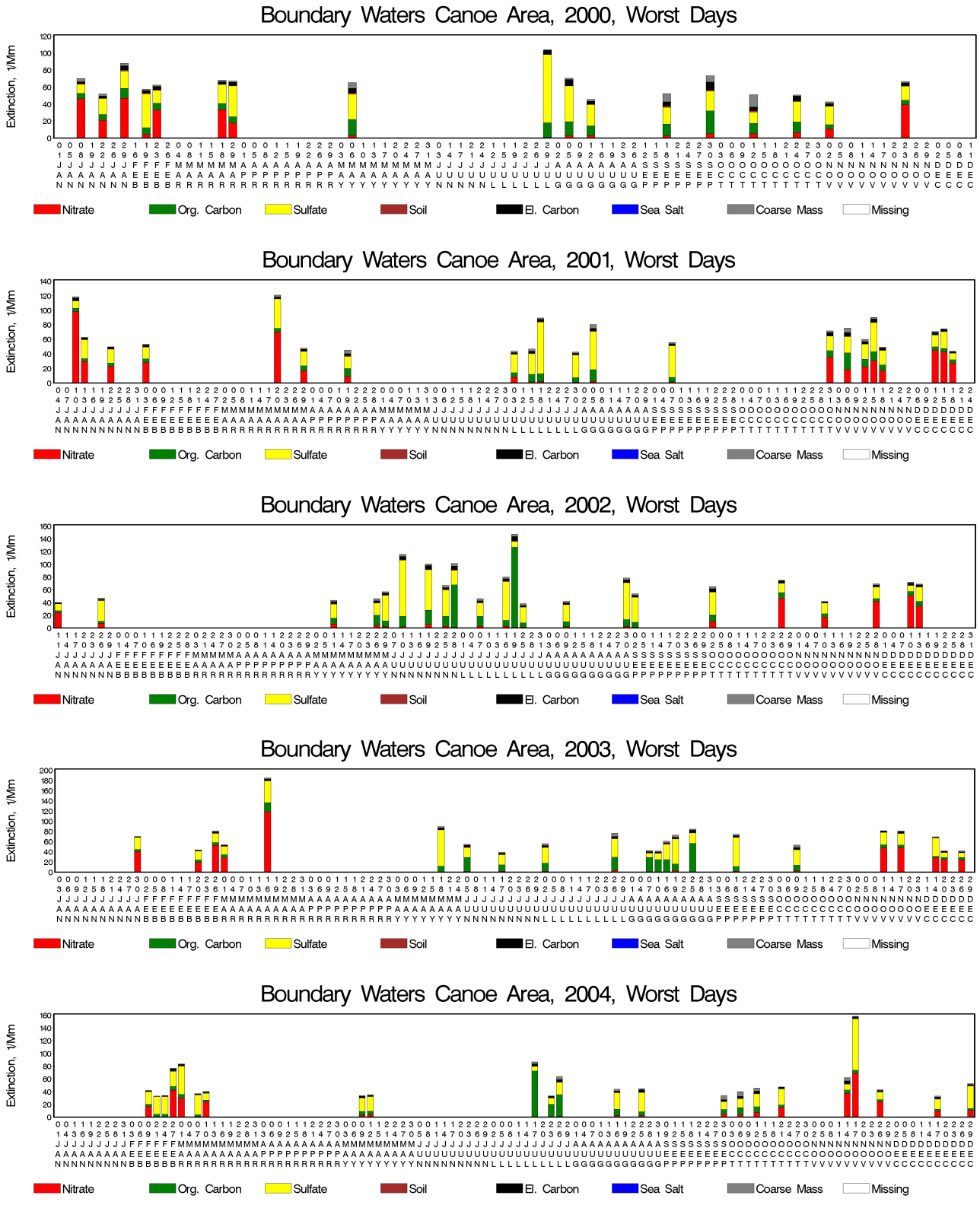


Figure 32. Daily light extinction values for 20% worst days at Boundary Waters (2000 – 2004)

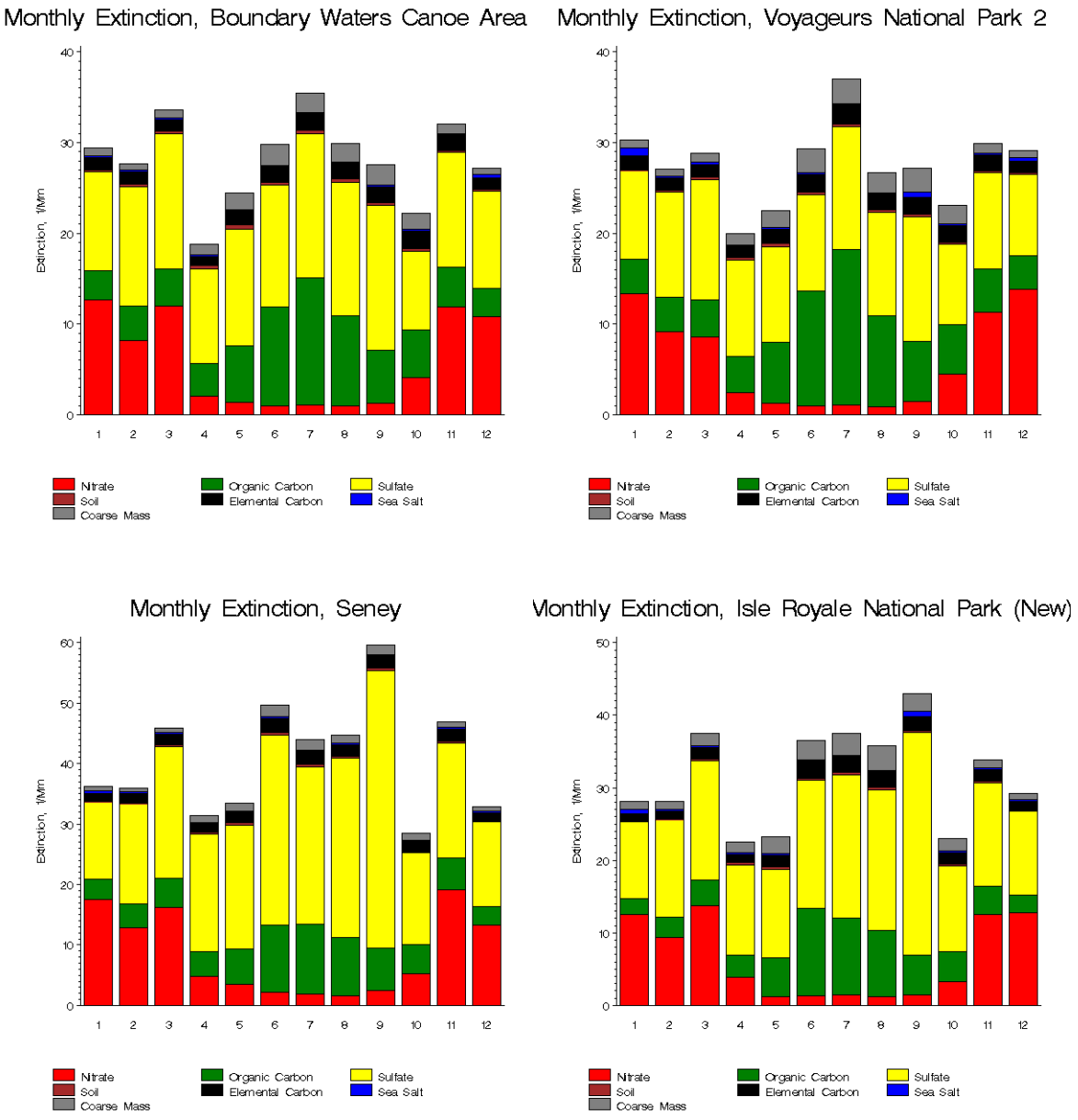


Figure 33. Monthly average light extinction values for northern Class I areas

Precursor Sensitivity: Results from two analyses using thermodynamic equilibrium models provide information on the effect of changes in precursor concentrations on $PM_{2.5}$ concentrations (and, in turn, visibility levels) in the northern Class I areas. First, a preliminary analysis using data collected at Seney indicated that $PM_{2.5}$ there is most sensitive to reductions in sulfate, but is also sensitive to reductions in nitric acid (Blanchard, 2004).

Second, an analysis was performed using data from the Midwest ammonia monitoring network for a site in Minnesota -- Great River Bluffs, which is the closest ammonia monitoring site to the northern Class I areas (Blanchard, 2005b). Figure 34 shows $PM_{2.5}$ concentrations as a function of sulfate, nitric acid (HNO3), and ammonia (NH3). Reductions in sulfate (i.e., movement to the left of baseline value [represented by the red star]), as well as reductions in nitric acid (i.e., movement downward) and NH3 (i.e., movement to the left), result in lower $PM_{2.5}$ concentrations. Thus, reductions in sulfate, nitric acid, and ammonia will lower $PM_{2.5}$ concentrations and improve visibility in the northern Class I areas.

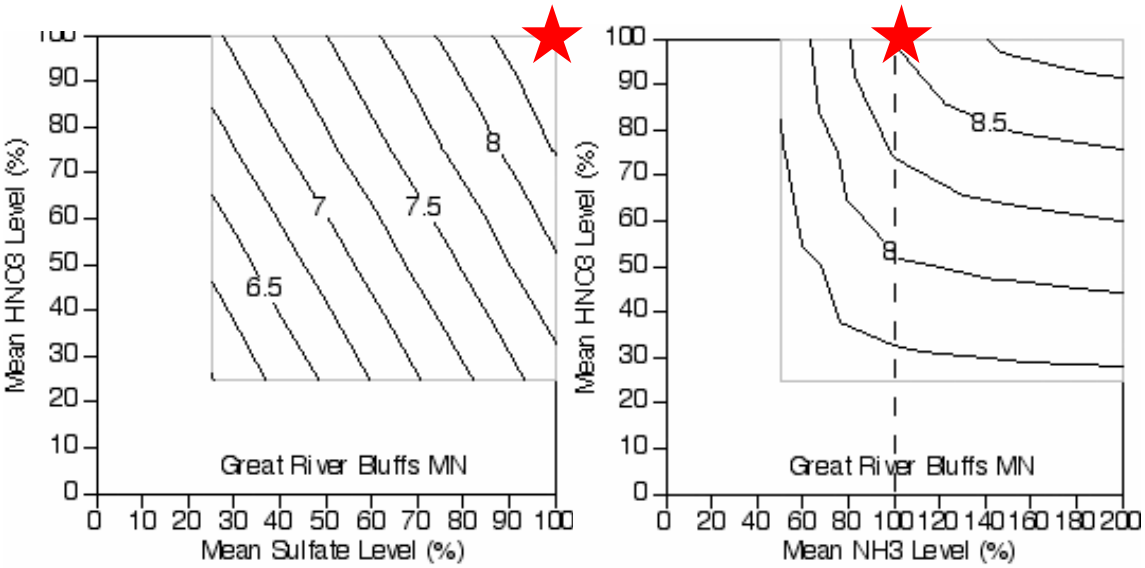


Figure 34. Predicted $PM_{2.5}$ mass concentrations at Great River Bluffs, MN as functions of changes in sulfate, nitric acid, and ammonia

Meteorology and Transport: The role of meteorology in haze is complex. Wind speed and wind direction govern the movement of air masses from polluted areas to the cleaner wilderness areas. As noted above, increasing humidity increases the efficiency with which sulfate and nitrate aerosols scatter light. Temperature and humidity together govern whether ammonium nitrate can form from its precursor gases, nitric acid and ammonia. Temperature and sunlight also play an indirect role in emissions of biogenic organic species that condense to form particulate organic matter; emissions increase in the summer daylight hours.

Trajectory analyses were performed to understand transport patterns for the 20% worst and 20% best visibility days. The composite results for the four northern Class I areas are provided in Figure 35. The orange areas are where the air is most likely to come from, and the green areas are where the air is least likely to come from. As can be seen, bad air days are generally associated with transport from regions located to the south, and good air days with transport from Canada.

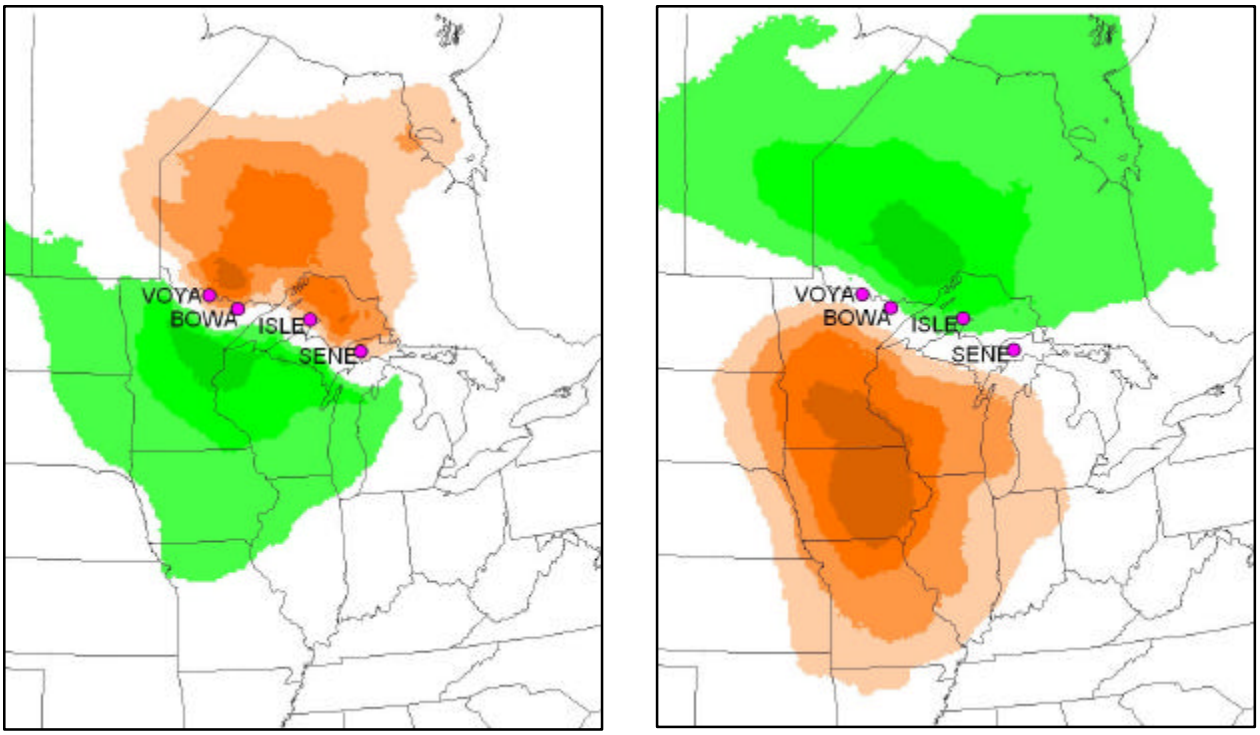


Figure 35. Composite back trajectories for light extinction- 20% best visibility days (left) and 20% worst visibility days (right) (2000 – 2005)

Source Culpability: Air quality data analyses (including the trajectory analyses above) and dispersion modeling were used to provide information on source region and source sector contributions to regional haze in the northern Class I areas (see MRPO, 2008). Based on this information, the most important contributing states are Michigan, Minnesota, and Wisconsin, as well as Missouri, North Dakota, Iowa, Indiana and Illinois (see, for example, Figure 35 above). The most important contributing pollutants and source sectors are SO2 emissions from electrical generating units (EGUs) and certain non-EGUs, which lead to sulfate formation, and NOx emissions from a variety of source types (e.g., motor vehicles), which lead to nitrate formation. Ammonia emissions from livestock waste and fertilizer applications are also important, especially for nitrate formation.

A source apportionment study was performed using monitoring data from Boundary Waters and statistical analysis methods (DRI, 2005). The study shows that a large portion of $PM_{2.5}$ mass consists of secondary, regional impacts, which cannot be attributed to individual facilities or sources (e.g., secondary sulfate, secondary nitrate, and secondary organic aerosols). Industrial sources contribute about 3-4% and mobile sources about 4-7% to $PM_{2.5}$ mass.

A special study was performed in Seney to identify sources of organic carbon (Sheesley, et al, 2004). As seen in Figure 36, the highest $PM_{2.5}$ concentrations occurred during the summer, with organic carbon being the dominant species. The higher summer organic carbon concentrations were attributed mostly to secondary organic aerosols of biogenic origin because of the lack of primary emission markers, and concentrations of know biogenic-related species (e.g., pinonic acid – see Figure 36) were also high during the summer.

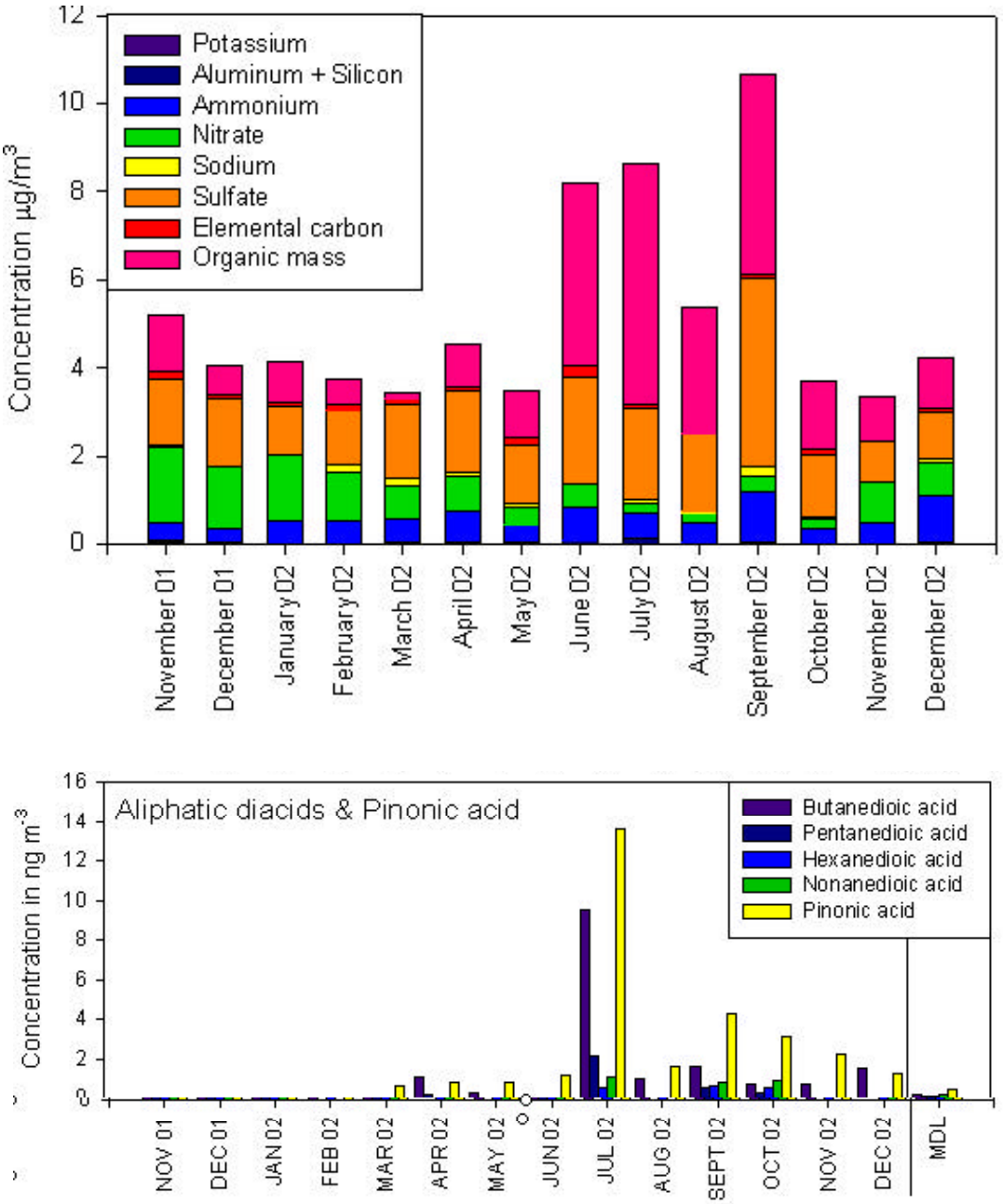


Figure 36. Monthly concentrations of $PM_{2.5}$ species (top), and secondary and biogenic-related organic carbon species in Seney (bottom)

Although the Seney study showed that biomass burning was a relatively small contributor to organic carbon on an annual average basis, episodic impacts are apparent (see, for example, high organic carbon days in Figure 32). To assess further whether burning is a significant contributor to visibility impairment in the northern Class I areas, the $PM_{2.5}$ chemical speciation data were examined for days with high organic carbon and elemental carbon concentrations, which are indicative of biomass burning impacts. Only a handful of such days were identified:

Table 5. Days with high OC and EC concentrations in northern Class I areas

Site	2000	2001	2002	2003	2004
Voyageurs	---	---	Jun 1	Aug 25	Jul 17
			Jun 28		
			Jul 19		
Boundary Waters	---	---	Jun 28	Aug 25	Jul 17
			Jul 19		
Isle Royale	---	---	Jun 1	Aug 25	---
			Jun 28		
Seney	---	---	Jun 28	---	---

Back trajectories on these days point mostly to wildfires in Canada. Elimination of these high organic carbon concentration days has a small effect in lowering the baseline visibility levels in the northern Class I areas (i.e., Minnesota Class I areas change by about 0.3 deciviews and Michigan Class I areas change by less than 0.2 deciviews). This suggests that fire activity, although significant on a few days, is on average a relatively small contributor to visibility impairment in the northern Class I areas.

In summary, these analyses show that organic carbon in the northern Class I is largely uncontrollable.

Section 3.0 Air Quality Modeling

Air quality models are relied on by federal and state regulatory agencies to support their planning efforts. Used properly, models can assist policy makers in deciding which control programs are most effective in improving air quality, and meeting specific goals and objectives. For example, models can be used to conduct "what if" analyses, which provide information for policy makers on the effectiveness of candidate control programs.

The modeling analyses were conducted in accordance with EPA's modeling guidelines (EPA, 2007a). Further details of the modeling are provided in two protocol documents: LADCO, 2007a and LADCO, 2007b.

This section reviews the development and evaluation of the modeling system used for the multi-pollutant analyses. Application of the modeling system (i.e., attainment demonstration for ozone and $PM_{2.5}$, and reasonable progress assessment for haze) is covered in the following sections.

3.1 Selection of Base Year

Two base years were used in the modeling analyses: 2002 and 2005. EPA's modeling guidance recommends using 2002 as the baseline inventory year, but also allows for use of an alternative baseline inventory year, especially a more recent year. Initially, LADCO conducted modeling with a 2002 base year (i.e., Base K/Round 4 modeling, which was completed in 2006). A decision was subsequently made to conduct modeling with a 2005 base year (i.e., Base M/Round 5, which was completed in 2007). As discussed in the previous section, 2002 and 2005 both had above normal ozone conducive conditions, although 2002 was more severe compared to 2005. Examination of multiple base years provides for a more complete technical assessment. Both sets of model runs are discussed in this document.

3.2 Future Years of Interest

To address the multiple attainment requirements for ozone and $PM_{2.5}$, and reasonable progress goals for regional haze, several future years are of interest:

- 2008 Planning year for ozone basic nonattainment areas (attainment date 2009)[8]
- 2009 Planning year for ozone moderate nonattainment areas and $PM_{2.5}$ nonattainment areas (attainment date 2010)
- 2012 Planning year for ozone moderate nonattainment areas and $PM_{2.5}$ nonattainment areas, with 3-year extension (attainment date 2013)
- 2018 First milestone year for regional haze planning

[8] According to USEPA's ozone implementation rule (USEPA, 2005), emission reductions needed for attainment must be implemented by the beginning of the ozone season immediately preceding the area's attainment date. The PM2.5 implementation rule contains similar provisions – i.e., emission reductions should be in place by the beginning of the year preceding the attainment date (USEPA, 2007c). The logic for requiring emissions reductions by the year (or season) immediately preceding the attainment year follows from language in the Clean Air Act, and the ability for an area to receive up to two 1-year extensions. Therefore, emissions in the year preceding the attainment year should be at a level that is consistent with attainment. It also follows that the year preceding the attainment year should be modeled for attainment planning purposes.

Detailed emissions inventories were developed for 2009 and 2018. To support modeling for other future years, less rigorous emissions processing was conducted (e.g., 2012 emissions were estimated for several source sectors by interpolating between 2009 and 2018 emissions).

3.3 Modeling System

The air quality analyses were conducted with the CAMx model, with emissions and meteorology generated using EMS (and CONCEPT) and MM5, respectively. The selection of CAMx as the primary model is based on several factors: performance, operator considerations (e.g., ease of application and resource requirements), technical support and documentation, model extensions (e.g., 2-way nested grids, process analysis, source apportionment, and plume-in-grid), and model science. CAMx model set-up for Base M and Base K is summarized below:

Base M (2005)	Base K (2002)
• CAMx v4.50	* CAMx 4.30
• CB05 gas phase chemistry	* CB-IV with updated gas-phase chemistry
• SOA chemistry updates	* No SOA chemistry updates
• AERMOD dry deposition scheme	* Wesley-based dry deposition
• ISORROPIA inorganic chemistry	• ISORROPIA inorganic chemistry
• SOAP organic chemistry	• SOAP organic chemistry
• RADM aqueous phase chemistry	• RADM aqueous phase chemistry
• PPM horizontal transport	• PPM horizontal transport

3.4 Domain/Grid Resolution

The National RPO grid projection was used for this modeling. A subset of the RPO domain was used for the LADCO modeling. For $PM_{2.5}$ and haze, the large eastern U.S. grid at 36 km (see box on right side of Figure 36) was used. A $PM_{2.5}$ sensitivity run was also performed for this domain at 12 km. For ozone, the smaller grid at 12 km (see shaded portion of the box on the right side of Figure 37) was used for most model runs. An ozone sensitivity run was also performed with a 4km sub-grid over the Lake Michigan area and Detroit/Cleveland.

The vertical resolution in the air quality model consists of 16 layers extending up to 15 km, with higher resolution in the boundary layer.

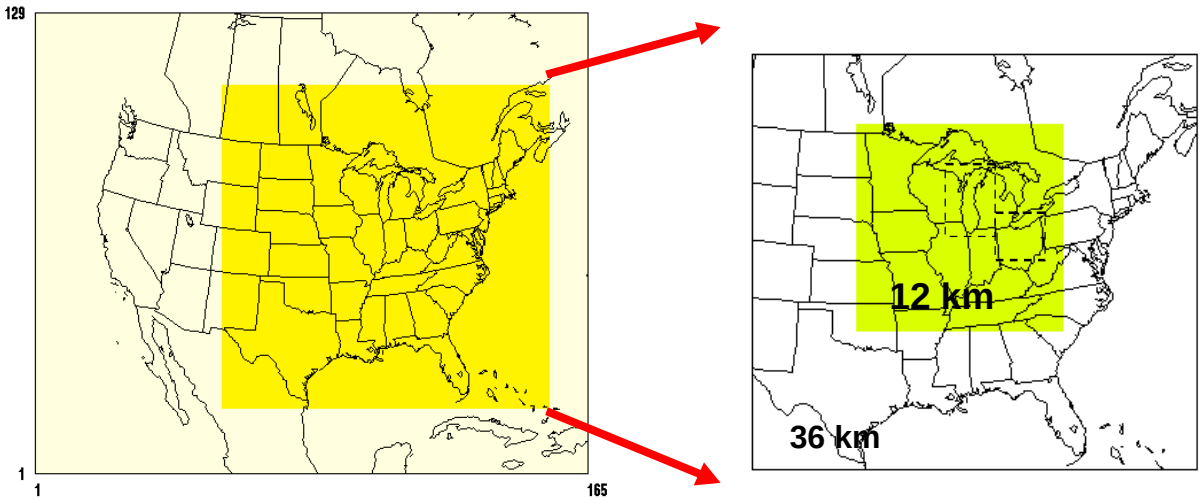


Figure 37. Modeling grids – RPO domain (left) and LADCO modeling domain (right)

3.5 Model Inputs: Meteorology

Meteorological inputs were derived using the Fifth-Generation NCAR/Penn State Meteorological Model (MM5) – version 3.6.3 for the years 2001–2003, and version 3.7 for the year 2005. The MM5 modeling domains are consistent with the National RPO grid projections (see Figure 38).

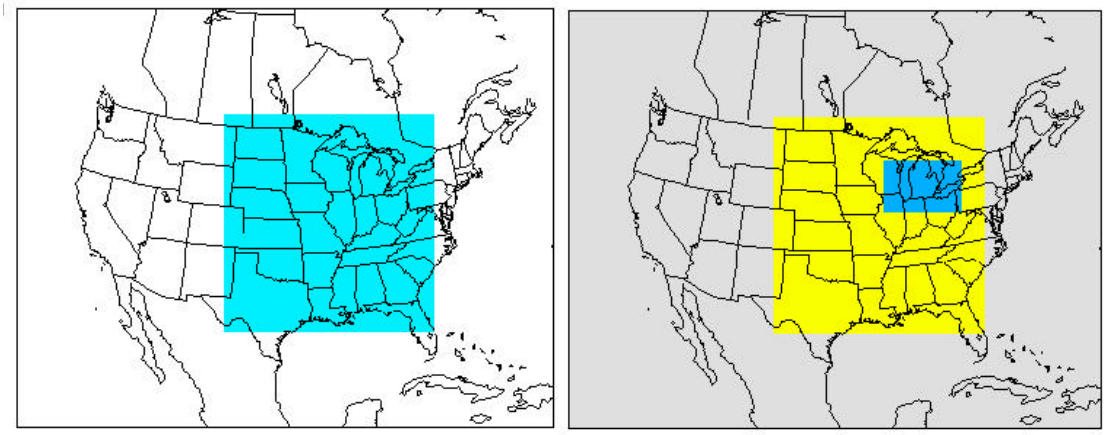


Figure 38. MM5 modeling domain for 2001-2003 (left) and 2005 (right)

The annual 2002 36 km MM5 simulation was completed by Iowa DNR. The 36/12 km 2-way nested simulation for the summers of 2001, 2002, and 2003 were conducted jointly by Illinois EPA and LADCO. The 36 km non-summer portion of the annual 2003 simulation was conducted by Wisconsin DNR. The annual 2005 36/12 km (and summer season 4 km) MM5 modeling was completed by Alpine Geophysics. Wisconsin DNR also completed 36/12 km MM5 runs for the summer season of 2005.

Model performance was assessed quantitatively with the METSTAT tool from Environ. The metrics used to quantify model performance include mean observation, mean prediction, bias, gross error, root mean square error, and index of agreement. Model performance metrics were calculated for several sub-regions of the modeling domain (Figure 39) and represent hourly spatial averages of multiple monitor locations. Additional analysis of rainfall is done on a monthly basis.

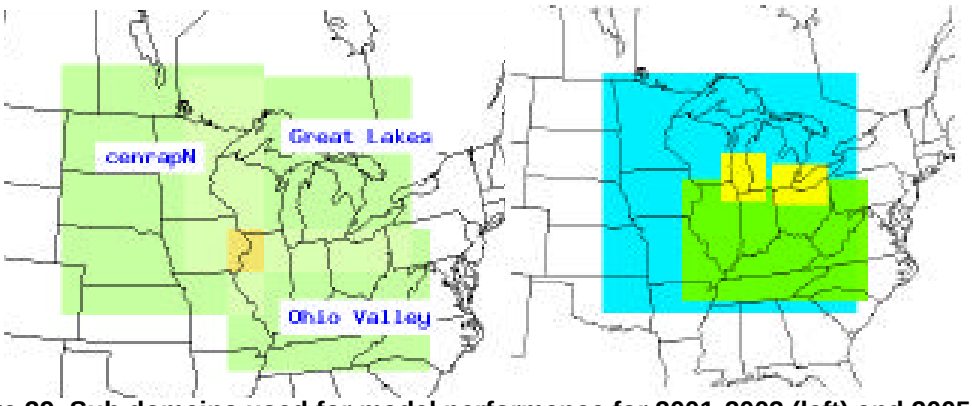


Figure 39. Sub-domains used for model performance for 2001-2003 (left) and 2005 (right)

A summary of the performance evaluation results for the meteorological modeling is provided below. Further details are provided in two summary reports (LADCO, 2005 and LADCO, 2007c).

Temperature: The biggest issue with the performance in the upper Midwest is the existence of a cool diurnal temperature bias in the winter and warm temperature bias over night during the summer (see Figure 40). These features are common to other annual MM5 simulations for the central United States and do not appear to adversely affect model performance.

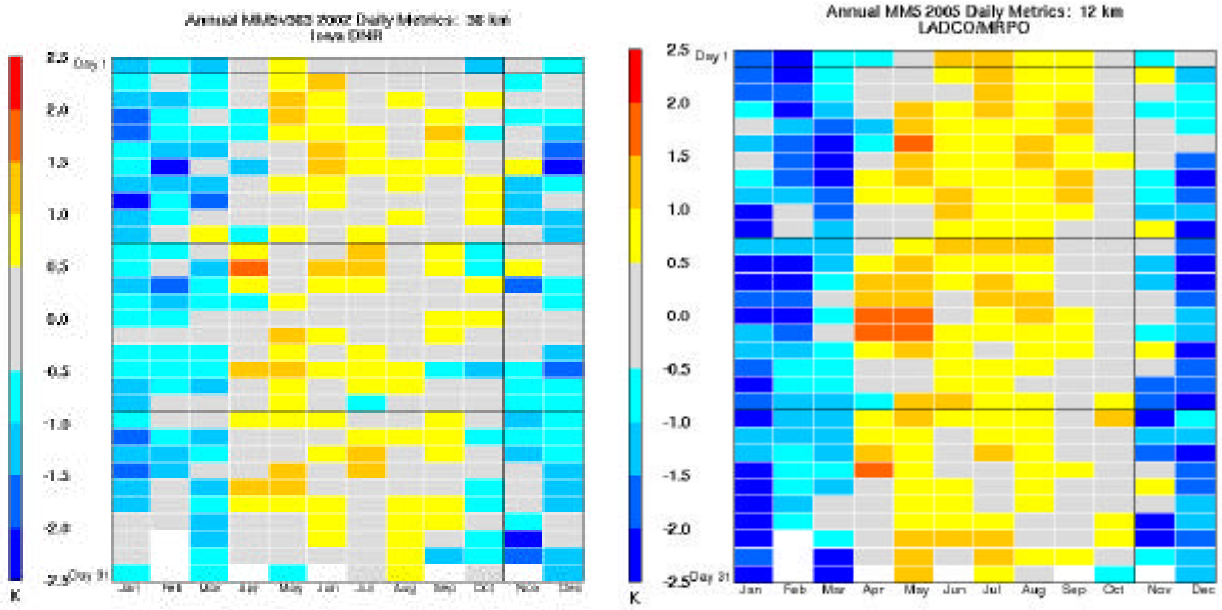


Figure 40. Daily temperature bias for 2002 (left) and 2005 (right) with hotter colors (yellow/orange/red) representing overestimates and cooler colors (blues) representing underestimates

Note: months are represented from left to right (January to December) and days are represented from top to bottom (1 to 30(31) – i.e., upper left hand corner is January 1 and lower right hand corner is December 31

Wind Fields: The wind fields are generally good. Wind speed bias is less than 0.5 m/sec and wind speed error is consistently between 1.0 and 1.5 m/sec. Wind direction error is generally within 15-30 degrees.

Mixing Ratio: The mixing ratio (a measure of humidity) is over-predicted in the late spring and summer months, and mixing ratio error is highest during this period. There is little bias and error during the cooler months when there is less moisture in the air.

Rainfall: The modeled and observed rainfall totals show good agreement spatially and in terms of magnitude in the winter, fall, and early spring months. There are, however, large over-predictions of rainfall in the late spring and summer months (see Figure 41). These over-predictions are seen spatially and in magnitude over the entire domain, particularly in the Southeast United States, and are likely due to excessive convective rainfall being predicted in MM5. This over-prediction of rainfall in MM5 does not necessarily translate into over-prediction of wet deposition in the photochemical model. CAMx does not explicitly use the convective and non-convective rainfall output by MM5, but estimates wet scavenging by hydrometeors using cloud, ice, snow, and rain water mixing ratios output by MM5. Nevertheless, this could have an effect on model performance for $PM_{2.5}$, as discussed in Section 3.7, and may warrant further attention.

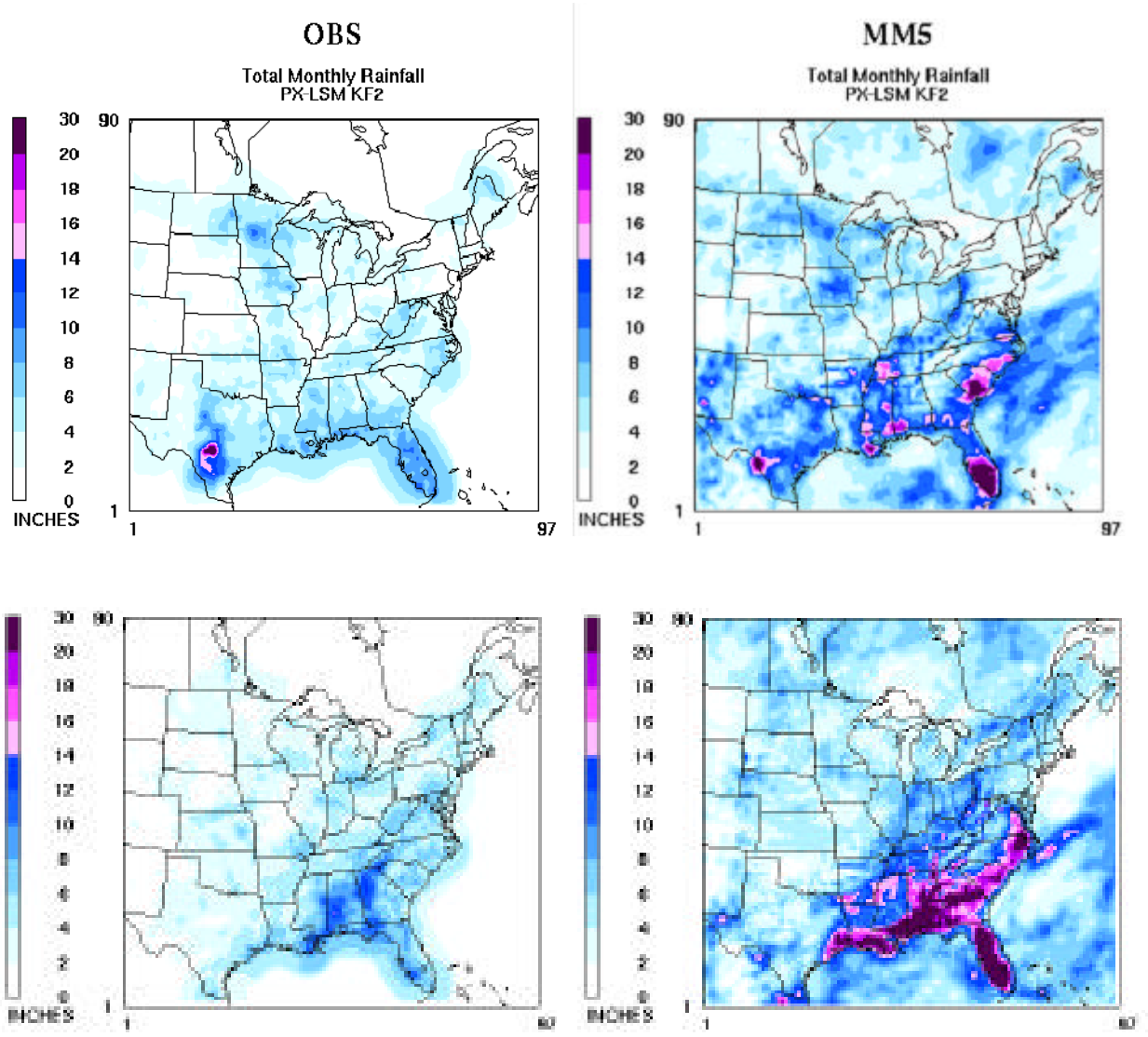


Figure 41. Comparison of observed (left column) and modeled (right column) monthly rainfall for July 2002 (top) and July 2005 (bottom)

3.6 Model Inputs: Emissions

Emission inventories were prepared for two base years: 2002 (Base K) and 2005 (Base M), and several future years: 2008, 2009, 2012, and 2018. Further details of the emission inventories are provided in two summary reports (LADCO, 2006a and LADCO, 2008a) and the following pages of the LADCO web site:

http://www.ladco.org/tech/emis/basek/BaseK_Reports.htm
http://www.ladco.org/tech/emis/r5/round5_reports.htm

For on-road, nonroad, ammonia, and biogenic sources, emissions were estimated by models. For the other sectors (point sources, area sources, and MAR [commercial marine, aircraft, and railroads]), emissions were prepared using data supplied by the LADCO States and other RPOs.

Base Year Emissions: State and source sector emission summaries for 2002 (Base K) and 2005 (Base M) are compared in Figure 42. Additional detail is provided in Tables 6a (all sectors – tons per day) and 6b (EGUs – tons per year).

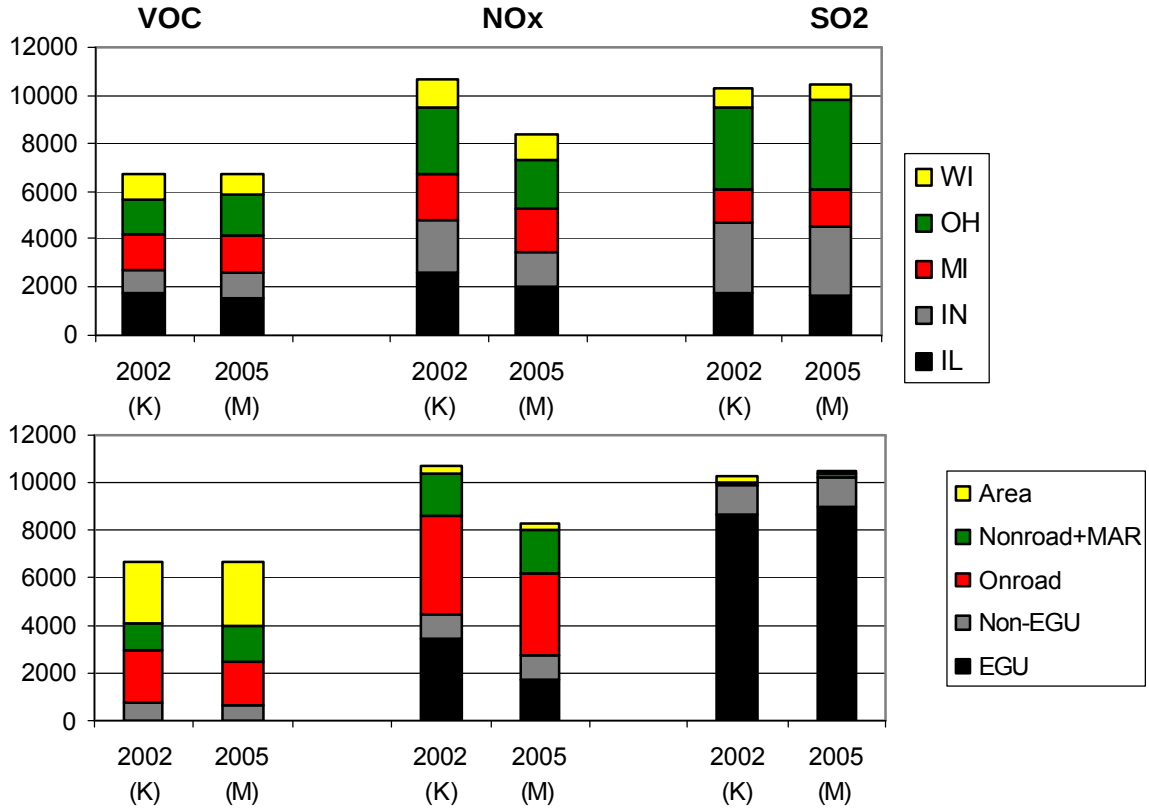


Figure 42. Base K and Base M emissions for 5-state LADCO region by state (top) and source sector (bottom), units: tons per summer weekday

A summary of the base year emissions by sector for the LADCO States is provided below.

	VOC	Base M	BaseK	Base M	BaseK	BaseK	Base M		NOx	Base M	BaseK	Base M	BaseK	BaseK	Base M		SOX	Base M	BaseK	Base M	BaseK	BaseK	Base M		PM2.5	Base M	BaseK	Base M	BaseK	BaseK	Base M
July	2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018
Nonroad																															
IL	224	321	164	257	149	130	213		324	333	263	275	224	154	155		31	33	5	5	0.6	0.4	0.4			30		24			14
IN	125	195	94	160	95	95	128		178	191	142	158	141	141	89		17	19	3	3	3	0.3	0.2			17		13			7
MI	348	414	307	350	276	222	271		205	239	159	197	133	93	112		19	22	3	3	0.5	0.3	0.3			22		18			11
OH	222	356	161	294	145	126	238		253	304	195	246	162	109	135		23	29	4	5	0.5	0.3	0.4			27		22			13
WI	214	238	194	203	175	140	157		145	157	114	129	97	69	77		13	15	2	2	0.3	0.2	0.2			14		12			7
5-State Total	1133	1524	920	1264	840	713	1007		1105	1224	873	1005	757	566	568		103	118	17	18	4.9	1.5	1.5			110		89			52
U.S. Total	8463	9815	5442	8448		5244	6581		6041	9060	6057	8120		5832	5100		505	654	117	153		104	13			573		750			475
MAR																															
IL	10	11	10	10	10	10	6		277	246	201	228	195	186	165		0	22	0	19	0	0	17			7		6			4
IN	5	5	5	5	5	5	3		123	93	89	87	87	84	65		0.2	8	0.2	7	0.2	0.2	6			2		2			2
MI	7	7	7	7	7	8	7		114	87	112	82	111	110	65		0.6	21	0.7	14	0.7	0.8	8			3		3			2
OH	8	7	8	7	8	8	5		177	134	128	126	126	122	94		0.4	14	0.3	12	0.3	0.3	10			4		4			2
WI	4	4	4	4	4	4	3		79	58	59	54	59	57	41		12.7	8	9.5	6	9.5	8.7	5			2		2			1
5-State Total	34	34	34	33	34	35	24		770	618	589	577	578	559	430		13.9	73	10.7	58	10.7	10	46			18		17			11
U.S. Total	307	317	321	157	329	346	334		4968	4515	4002	1813	3964	3919	3812		620	512	509	122	509	503	290			147		57			165
OtherArea																															
IL	679	675	688	594	700	738	582		62	48	68	48	70	73	49		11	11	12	16	12	13	16			40		64			69
IN	354	391	365	358	373	398	384		62	56	65	58	67	69	59		158	32	150	32	151	153	32			2		2			2
MI	518	652	516	562	520	541	549		49	49	52	50	53	54	51		71	29	68	29	68	68	28			111		114			120
OH	546	604	550	506	558	593	487		50	93	59	108	60	62	108		22	6	34	15	35	35	14			19		35			34
WI	458	315	467	290	474	506	293		32	37	34	37	34	35	37		9	17	9	13	10	10	13			11		12			12
5-State Total	2555	2637	2586	2310	2625	2776	2295		255	283	278	301	284	293	304		271	95	273	105	276	279	103			183		227			237
U.S. Total	17876	21093	18638	18683		20512	24300		3856	4899	4100	4220		4418	5357		2075	2947	2062	2559		2189	2709			2735		2621			2570
On-Road																															
IL	446	341	314	268	260	197	151		890	748	578	528	474	300	201			9		4			3			13		10			6
IN	405	282	237	235	193	150	138		703	541	425	402	313	187	173			11		3			2			9		7			2
MI	522	351	335	269	303	217	163		926	722	680	501	619	385	204			14		4			3			12		9			3
OH	574	680	365	424	340	238	242		1035	934	609	693	512	270	274			18		4			4			16		12			4
WI	238	175	144	119	117	88	68		481	457	303	322	226	118	138			9		2			2			8		6			2
5-State Total	2185	1829	1395	1315	1213	890	762		4035	3402	2595	2446	2144	1260	990			61		17			14			58		44			17
U.S. Total	14263				7825				23499				13170																		
EGU																															
IL	9	7	8	6	8	9	7		712	305	227	275	244	231	224		1310	1158	944	958	789	810	869			13		34			77
IN	6	6	6	6	7	6	6		830	393	406	370	424	283	255		2499	2614	1267	1033	1263	1048	1036			16		73			74
MI	12	6	11	4	11	12	4		448	393	218	242	219	247	243		1103	1251	1022	667	1031	1058	725			15		25			29
OH	5	4	6	5	7	7	6		1139	408	330	280	322	271	285		3131	3405	1463	1326	994	701	983			28		94			80
WI	3	5	3	2	4	4	3		293	213	146	165	139	147	177		602	545	512	460	492	500	435			0		22			25
5-State Total	35	28	34	23	37	38	26		3422	1712	1327	1332	1348	1179	1184		8645	8973	5208	4444	4569	4117	4048			72		248			285
U.S. Total	214	140	195	124	197	215	138		14371	10316	7746	7274	7721	7007	6095		31839	34545	20163	16903	17629	14727	14133			685		1131			1571
Non-EGU																															
IL	313	221	286	218	305	350	258		356	330	334	218	338	343	235		373	423	251	335	257	249	346			16		17			19
IN	150	130	160	137	170	199	167		238	179	212	175	216	225	178		292	218	270	216	274	290	180			35		36			44
MI	123	116	115	119	122	139	140		216	240	208	242	214	229	271		162	158	166	148	171	185	163			20		21			25
OH	77	84	75	87	79	90	104		177	175	157	166	160	167	178		240	289	231	288	210	216	293			27		28			33
WI	88	84	97	87	104	120	106		98	97	91	93	92	94	81		163	156	154	152	155	156	85			0		0.1			0.1
5-State Total	751	635	733	648	780	898	775		1085	1021	1002	894	1020	1058	943		1230	1244	1072	1139	1067	1096	1067			98		102			121
U.S. Total	4087	3877	4409		4700	5378			6446	6730	6129		6435	6952			5759	5630	6093		6340	6970						1444			1777
IL	1681	1576	1470	1353	1432	1434	1217		2621	2010	1671	1572	1545	1287	1029		1725	1656	1212	1337	1059	1072	1251			119		155			189
IN	1045	1009	867	901	843	853	826		2134	1453	1339	1250	1248	989	819		2966	2902	1690	1294	1691	1492	1256			81		133			131
MI	1530	1546	1291	1311	1239	1139	1134		1958	1730	1429	1314	1349	1118	946		1356	1495	1260	865	1271	1312	927			183		190			190
OH	1432	1735	1165	1323	1137	1062	1082		2831	2048	1478	1619	1342	1001	1074		3416	3761	1732	1650	1240	953	1304			121		195			166
WI	1005	821	909	705	878	862	630		1128	1019	747	800	647	520	551		800	750	687	635	667	675	540			35		54			47
5-State Total	6693	6687	5702	5593	5529	5350	4889		10672	8260	6664	6555	6131	4915	4419		10263	10564	6581	5781	5928	5504	5280			539		727			723

Table 6b. EGU Emissions for Midwest States (2018)						
	Heat Input (MMBTU/year)	**Scenario**	**SO2 (tons/year)**	**SO2 (lb/MMBTU)**	**NOx (tons/year)**	**NOx (lb/MMBTU)**
IL	**980,197,198**	**2001 - 2003 (average)**	**362,417**	**0.74**	**173,296**	**0.35**
		IPM 2.1.9	241,000		73,000	
	1,310,188,544	IPM3.0 (base)	277,337	0.423	70,378	0.107
		IPM3.0 - will do	140,296	0.214	62,990	0.096
		IPM3.0 - may do	140,296	0.214	62,990	0.096
IN	**1,266,957,401**	**2001 - 2003 (average)**	**793,067**	**1.25**	**285,848**	**0.45**
		IPM 2.1.9	377,000		95,000	
	1,509,616,931	IPM3.0 (base)	361,835	0.479	90,913	0.120
		IPM3.0 - will do	417,000	0.552	94,000	0.125
		IPM3.0 - may do	417,000	0.552	94,000	0.125
MI	**756,148,700**	**2001 - 2003 (average)**	**346,959**	**0.92**	**132,995**	**0.35**
		IPM 2.1.9	399,000		100,000	
	1,009,140,047	IPM3.0 (base)	244,151	0.484	79,962	0.158
		IPM3.0 - will do	244,151	0.484	79,962	0.158
		IPM3.0 - may do	244,151	0.484	79,962	0.158
OH	**1,306,296,589**	**2001 - 2003 (average)**	**1,144,484**	**1.75**	**353,255**	**0.54**
		IPM 2.1.9	216,000		84,000	
	1,628,081,545	IPM3.0 (base)	316,883	0.389	96,103	0.118
		IPM3.0 - will do	348,000		101,000	
		IPM3.0 - may do	348,000		101,000	
WI	**495,475,007**	**2001 - 2003 (average)**	**191,137**	**0.77**	**90,703**	**0.36**
		IPM 2.1.9	155,000		46,000	
	675,863,447	IPM3.0 (base)	127,930	0.379	56,526	0.167
		IPM3.0 - will do	150,340	0.445	55,019	0.163
		IPM3.0 - may do	62,439	0.185	46,154	0.137
IA	**390,791,671**	**2001 - 2003 (average)**	**131,080**	**0.67**	**77,935**	**0.40**
		IPM 2.1.9	147,000		51,000	
	534,824,314	IPM3.0 (base)	115,938	0.434	59,994	0.224
		IPM3.0 - will do	115,938	0.434	59,994	0.224
		IPM3.0 - may do	100,762	0.377	58,748	0.220
MN	**401,344,495**	**2001 - 2003 (average)**	**101,605**	**0.50**	**85,955**	**0.42**
		IPM 2.1.9	86,000		42,000	
	447,645,758	IPM3.0 (base)	61,739	0.276	41,550	0.186
		IPM3.0 - will do	54,315	0.243	49,488	0.221
		IPM3.0 - may do	51,290	0.229	39,085	0.175
MO	**759,902,542**	**2001 - 2003 (average)**	**241,375**	**0.63**	**143,116**	**0.37**
		IPM 2.1.9	281,000		78,000	
	893,454,905	IPM3.0 (base)	243,684	0.545	72,950	0.163
		IPM3.0 - will do	237,600	0.532	72,950	0.163
		IPM3.0 - may do	237,600	0.532	72,950	0.163
ND	**339,952,821**	**2001 - 2003 (average)**	**145,096**	**0.85**	**76,788**	**0.45**
		IPM 2.1.9	109,000		72,000	
	342,685,501	IPM3.0 (base)	41,149	0.240	44,164	0.258
		IPM3.0 - will do	56,175	0.328	58,850	0.343
		IPM3.0 - may do	56,175	0.328	58,850	0.343
SD	**39,768,357**	**2001 - 2003 (average)**	**12,545**	**0.63**	**15,852**	**0.80**
		IPM 2.1.9	12,000		15,000	
	44,856,223	IPM3.0 (base)	4,464	0.199	2,548	0.114
		IPM3.0 - will do	4,464	0.199	2,548	0.114
		IPM3.0 - may do	4,464	0.199	2,548	0.114

On-road Sources: For 2002, EMS was run by LADCO using VMT and MOBILE6 inputs supplied by the LADCO States. EMS was run to generate 36 days (weekday, Saturday, Sunday for each month) at 36 km, and 9 days (weekday, Saturday, Sunday for June – August) at 12 km. For 2005, CONCEPT was run by a contractor (Environ) using transportation data (e.g., VMT and vehicle speeds) supplied by the state and local planning agencies in the LADCO States and Minnesota for 24 networks. These data were first processed with T3 (Travel Demand Modeling [TDM] Transformation Tool) to provide input files for CONCEPT to calculate link-specific, hourly emission estimates (Environ, 2008). CONCEPT was run with meteorological data for a July and January weekday, Saturday, and Sunday (July 15 – 17 and January 16 – 18). A spatial plot of emissions is provided in Figure 43.

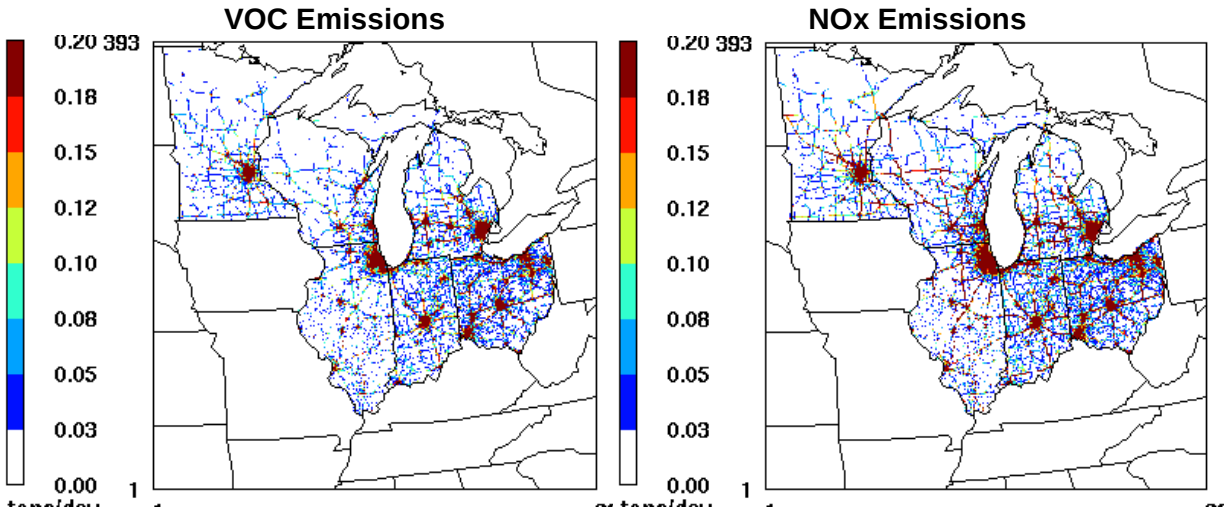


Figure 43. Motor vehicle emissions for VOC (left) and NOx (right) for a July weekday (2005)

Off-road Sources: For 2002 and 2005, NMIM and NMIM2005, respectively, were run by Wisconsin DNR. Additional off-road sectors (i.e., commercial marine, aircraft, and railroads [MAR]) were handled separately. Local data for agricultural equipment, construction equipment, commercial marine, recreational marine, and railroads were prepared by contractors (Environ, 2004, and E.H. Pechan, 2004). For Base M, updated local data for railroads and commercial marine were prepared by a contractor (Environ, 2007b, 2007c). Table 7 compares the Base M 2005 and Base K 2002 emissions. Compared to 2002, the new 2005 emissions reflect substantially lower commercial marine emissions and lower locomotive NOx emissions.

Table 7. Locomotive and commercial marine emissions for the five LADCO States (2002 v. 2005)

	Railroads (TPY)			Commercial Marine (TPY)	
	2002	**2005**		**2002**	**2005**
VOC	7,890	7,625		1,562	828
CO	20,121	20,017		8,823	6,727
NOx	182,226	145,132		64,441	42,336
PM	5,049	4,845		3,113	1,413
SO2	12,274	12,173		25,929	8,637
NH3	86	85		----	----

Area Sources: For 2002 and 2005, EMS was run by LADCO using data supplied by the LADCO States to produce weekday, Saturday, and Sunday emissions for each month. For 2005, special attention was given to two source categories: industrial adhesive and sealant solvents (which were dropped from the inventory to avoid double-counting) and outdoor wood boilers (which were added to the inventory).

Point Sources: For 2002 and 2005, EMS was run by LADCO using data supplied by the LADCO States to produce weekday, Saturday, and Sunday emissions for each month. For EGUs, the annual and summer season emissions were temporalized for modeling purposes using profiles prepared by Scott Edick (Michigan DEQ) based on CEM data.

Biogenics: For Base M, a contractor (Alpine) provided an updated version of the CONCEPT/MEGAN biogenics model. Compared to the previous (EMS/BIOME) emissions, there is more regional isoprene using MEGAN compared to the BIOME estimates used for Base K (see Figure 44). Also, with the secondary organic aerosol updates to the CAMx air quality model, Base M includes emissions for monoterpenes and sesquiterpenes, which are pre-cursors of secondary $PM_{2.5}$ organic carbon mass.

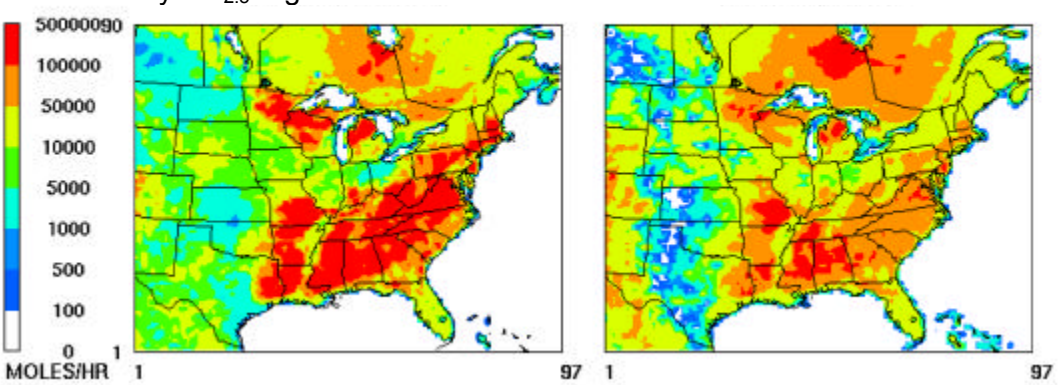


Figure 44. Isoprene emissions for Base M (left) v. Base K (right)

Ammonia: For Base M, the CMU-based 2002 (Base K) ammonia emissions were projected to 2005 using growth factors from the Round 4 emissions modeling. These emissions were then adjusted by applying temporal factors by month based on the process-based ammonia emissions model (Zhang, et al, 2005, and Mansell, et al, 2005). A plot of average daily emissions by state and month is provided in Figure 45. A spatial plot of emissions is provided in Figure 46, which shows high emissions densities in the central U.S.

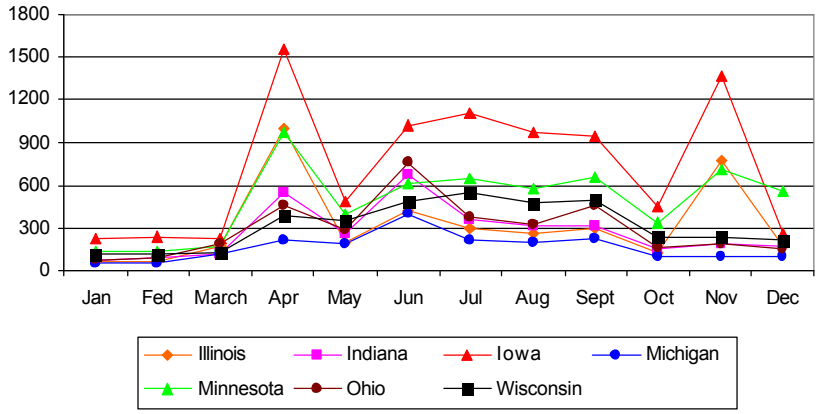


Figure 45. Average daily ammonia emissions for Midwest States by month (2005) - (units: average daily emissions – tons per day)

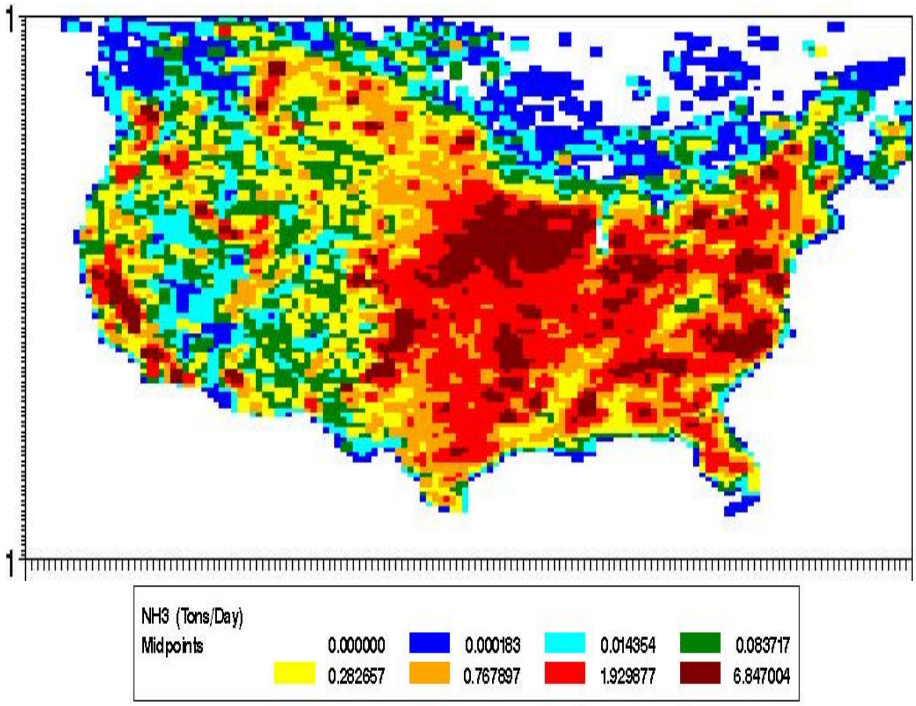


Figure 46. Ammonia emissions for a July weekday (2005) – 12 km modeling domain

Canadian Emissions: For Base M, Scott Edick (Michigan DEQ) processed the 2005 Canadian National Pollutant Release Inventory, Version 1.0 (NPRI). Specifically, a subset of the NPRI data (emissions and stack parameters) relevant to the air quality modeling were reformatted. The resulting emissions represent a significant improvement in the base year emissions.

A spatial plot of point source SO2 and NOx emissions is provided in Figure 47. Additional plots and emission reports are available on the LADCO website (http://www.ladco.org/tech/emis/basem/canada/index.htm).

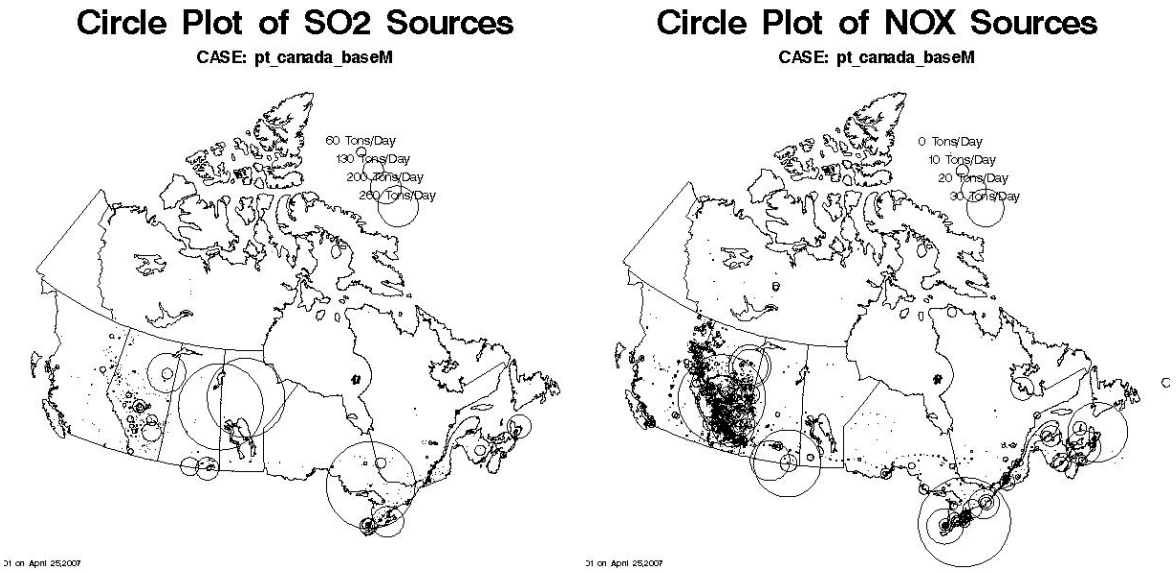


Figure 47. Canadian point source emissions for SO2 (left) and NOx (right)

Fires: For Base K, a contractor (EC/R, 2004) developed a 2001, 2002, and 2003 fire emissions inventory for eight Midwest States (five LADCO states plus Iowa, Minnesota, and Missouri), including emissions from wild fires, prescribed fires, and agricultural burns. Projected emissions were also developed for 2010 and 2018 assuming "no smoke management" and "optimal smoke management" scenarios. An early model sensitivity run showed very little difference in modeled $PM_{2.5}$ concentrations. Consequently, the fire emissions were not included in subsequent modeling runs (i.e., they were not in the Base K or Base M modeling inventories).

Future Year Emissions: Complete emission inventories were developed for several future years: Base K – 2009, 2012, and 2018, and Base M – 2009 and 2018. In addition, 2008 (Base K and Base M) and 2012 (Base M) proxy inventories were estimated based on the 2009 and 2018 data. (Note, the EGU emissions for the Base M 2012 inventory were based on EPA's IPM3.0 modeling.)

Source sector emission summaries for the base years and future years are shown in Figure 48. Additional detail is provided in Tables 6a and 6b.

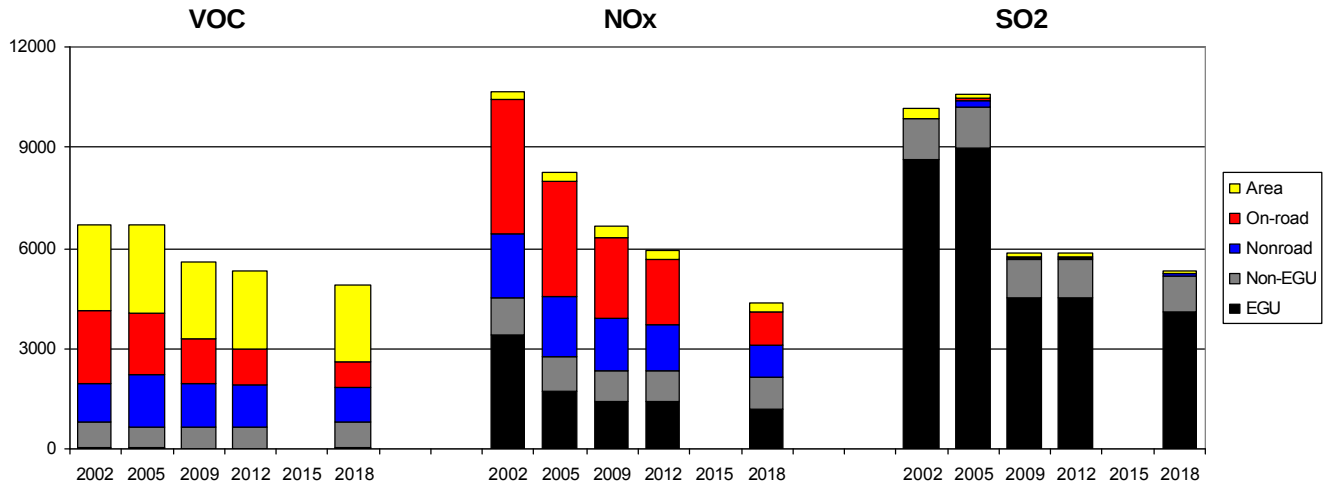


Figure 48. Base year and future year emissions for 5-State LADCO Region (TPD, July weekday)

For on-road, and nonroad, the future year emissions were estimated by models (i.e., EMS/CONCEPT and NMIM, respectively). One adjustment was made to the 2009 and 2018 motor vehicle emission files prepared by Environ with CONCEPT. To reflect newer transportation modeling conducted by CATS for the Chicago area, emissions were increased by 9% in 2009 and 2018. The 2005 base year and adjusted 2009 and 2018 motor vehicle emissions are provided in Table 8.

Table 8. Motor Vehicle Emissions Produced by CONCEPT Modeling (July weekday – tons per day)

Year	State	Sum of CO	Sum of TOG	Sum of NOx	Sum of PM2.5	Sum of SO2	Sum of NH3	Sum of VMT
2005	IL	3,684.3	341.5	748.2	12.9	9.6	35.9	344,087,819.6
	IN	3,384.9	282.0	541.1	8.9	11.1	25.7	245,537,231.9
	MI	4,210.3	351.9	722.0	12.4	13.9	35.3	340,834,025.9
	MN	2,569.1	218.7	380.5	6.3	7.6	17.7	170,024,599.7
	OH	6,113.4	679.8	933.6	16.2	18.8	36.5	360,521,068.6
	WI	2,206.0	175.1	457.5	7.8	9.2	19.7	189,123,964.3
Total		22,168.0	2,049.0	3,782.9	64.5	70.2	170.8	1,650,128,709.9
2009	IL	2,824.4	268.0	527.8	10.1	4.2	38.9	372,132,591.1
	IN	2,839.5	234.9	401.9	6.7	2.8	26.1	249,817,026.3
	MI	3,172.0	269.2	500.9	9.2	4.0	37.1	356,347,010.5
	MN	2,256.8	206.3	307.5	5.1	2.3	21.5	204,443,017.8
	OH	4,619.2	423.7	693.5	11.8	4.7	39.5	387,428,127.2
	WI	1,673.4	119.4	322.1	5.7	2.3	20.6	197,729,964.9
Total		17,385.3	1,521.5	2,753.6	48.7	20.3	183.6	1,767,897,737.8
2018	IL	2,084.7	151.5	200.7	6.3	3.7	43.1	413,887,887.3
	IN	2,217.3	138.4	173.0	4.4	2.6	30.2	288,042,232.1
	MI	2,434.3	163.5	204.1	5.9	3.6	40.5	388,128,431.8
	MN	1,799.6	123.1	137.1	3.6	2.2	24.9	237,022,213.7
	OH	3,361.5	242.5	274.1	6.8	4.0	43.1	421,694,093.4
	WI	1,255.5	68.4	138.5	3.9	2.0	22.2	218,277,167.5
Total		13,152.9	887.5	1,127.5	30.8	18.1	203.9	1,967,052,025.8

For EGUs, future year emissions were based on IPM2.1.9 modeling completed by the RPOs in July 2005 Base K and IPM3.0 completed by EPA in February 2007 for Base M. Several CAIR scenarios were assumed:

Base K
1a: IPM2.1.9, with full trading and banking
1b: IPM2.1.9, with restricted trading (compliance with state-specific emission budgets) and full trading
1d: IPM2.1.9, with restricted trading (compliance with state-specific emission budgets)

Base M
5a: EPA's IPM3.0 was assumed as the future year base for EGUs.
5b: EPA's IPM3.0, with several "will do" adjustments identified by the States. These adjustments should reflect a legally binding commitment (e.g., signed contract, consent decree, or operating permit).
5c: EPA's IPM3.0, with several "may do" adjustments identified by the States. These adjustments reflect less rigorous criteria, but should still be some type of public reality (e.g., BART determination or press announcement).

For other sectors (area, MAR, and non-EGU point sources), the future year emissions for the LADCO States were derived by applying growth and control factors to the base year inventory. These factors were developed by a contractor (E.H. Pechan, 2005 and E.H. Pechan, 2007). For the non-LADCO States, future year emission files were based on data from other RPOs.

Growth factors were based initially on EGAS (version 5.0), and were subsequently modified (for select, priority categories) by examining emissions activity data. Due to a lack of information on future year conditions, the biogenic VOC and NOx emissions, and all Canadian emissions were assumed to remain the constant between the base year and future years.

A "base" control scenario was prepared for each future year based on the following "on the books" controls:

On-Highway Mobile Sources
- Federal Motor Vehicle Emission Control Program, low-sulfur gasoline and ultra-low sulfur diesel fuel
- Inspection - maintenance programs, including IL's vehicle emissions tests (NE IL), IN's vehicle emissions testing program (NW IN), OH's E-check program (NE OH), and WI's vehicle inspection program (SE WI) – note: a special emissions modeling run was done for the Cincinnati/Dayton area to reflect the removal of the state's E-check program and inclusion of low RVP gasoline
- Reformulated gasoline, including in Chicago-Gary,-Lake County, IL,IN; and Milwaukee, Racine, WI

Off-Highway Mobile Sources
- Federal control programs incorporated into NONROAD model (e.g., nonroad diesel rule), plus the evaporative Large Spark Ignition and Recreational Vehicle standards
- Heavy-duty diesel (2007) engine standard/Low sulfur fuel
- Federal railroad/locomotive standards
- Federal commercial marine vessel engine standards

Area Sources (Base M only)
- Consumer solvents
- AIM coatings
- Aerosol coatings
- Portable fuel containers

Power Plants
- Title IV (Phases I and II)
- NOx SIP Call
- Clean Air Interstate Rule

Other Point Sources

- VOC 2-, 4-, 7-, and 10-year MACT standards
- Combustion turbine MACT

Other controls included in the modeling include: consent decrees (refineries, ethanol plants, and ALCOA)[9], NOx RACT in Illinois and Ohio[10], and BART for a few non-EGU sources in Indiana and Wisconsin.

For Base K, several additional control scenarios were considered:

Scenario 2 – "base" controls plus additional controls recommended in LADCO White Papers for stationary and mobile sources

Scenario 3 – Scenario 2 plus additional White Papers for stationary and mobile sources

Scenario 4 – "base" controls plus additional candidate control measures under discussion by State Commissioners

Scenario 5 – "base" controls plus additional candidate control measures identified by the LADCO Project Team

3.7 Basecase Modeling Results

The purpose of the basecase modeling is to evaluate model performance (i.e., assess the model's ability to reproduce the observed concentrations). The model performance evaluation focused on the magnitude, spatial pattern, and temporal of modeled and measured concentrations. This exercise was intended to assess whether, and to what degree, confidence in the model is warranted (and to assess whether model improvements are necessary).

Model performance was assessed by comparing modeled and monitored concentrations. Graphical (e.g., side-by-side spatial plots, time series plots, and scatter plots) and statistical analyses were conducted. No rigid acceptance/rejection criteria were used for this study. Instead, the statistical guidelines recommended by EPA and other modeling studies (e.g., modeling by the other RPOs) were used to assess the reasonableness of the results. The model performance results presented here describe how well the model replicates observed ozone and $PM_{2.5}$ concentrations after a series of iterative improvements to model inputs.

Ozone: Spatial plots are provided for high ozone periods in June 2002 and June 2005 (see Figures 49a and 49b). The plots show that the model is doing a reasonable job of reproducing the magnitude, day-to-day variation, and spatial pattern of ozone concentrations. There is a tendency, however, to underestimate the magnitude of regional ozone levels. This is more apparent with the 2002 modeling; the regional concentrations in the 2005 modeling agree better with observations due to model and inventory improvements.

[9] E.H. Pechan's original control file included control factors for three sources in Wayne County, MI. These control factors were not applied in the regional-scale modeling to avoid double-counting with the State's local-scale analysis for PM2.5

[10] NOx RACT in Wisconsin is included in the 2005 basecase (and EGU "will do" scenario). NOx RACT in Indiana was not included in the modeling inventory.

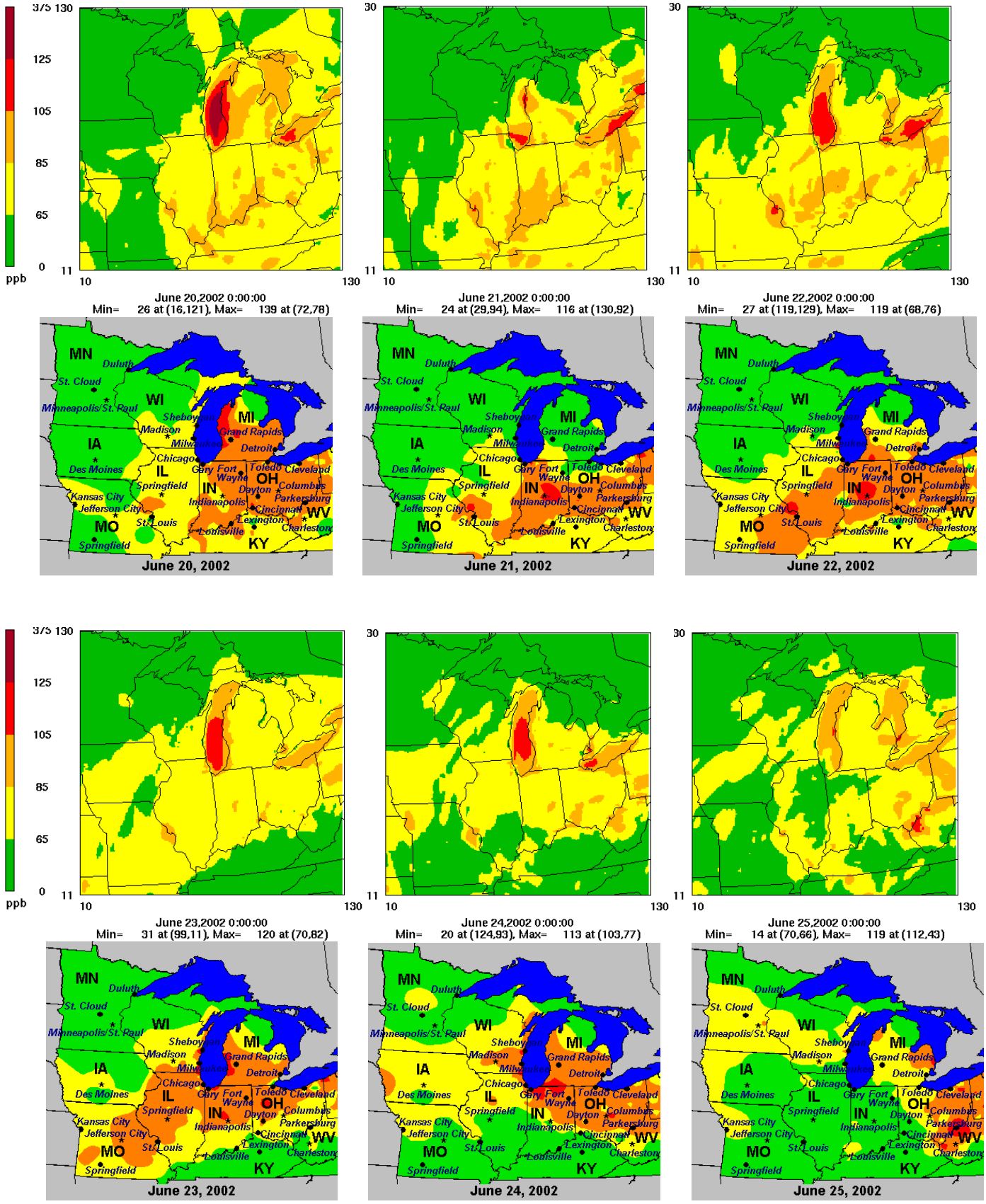


Figure 49a. Modeled (top) v. monitored (bottom) 8-hour ozone concentrations: June 20 – 25, 2002

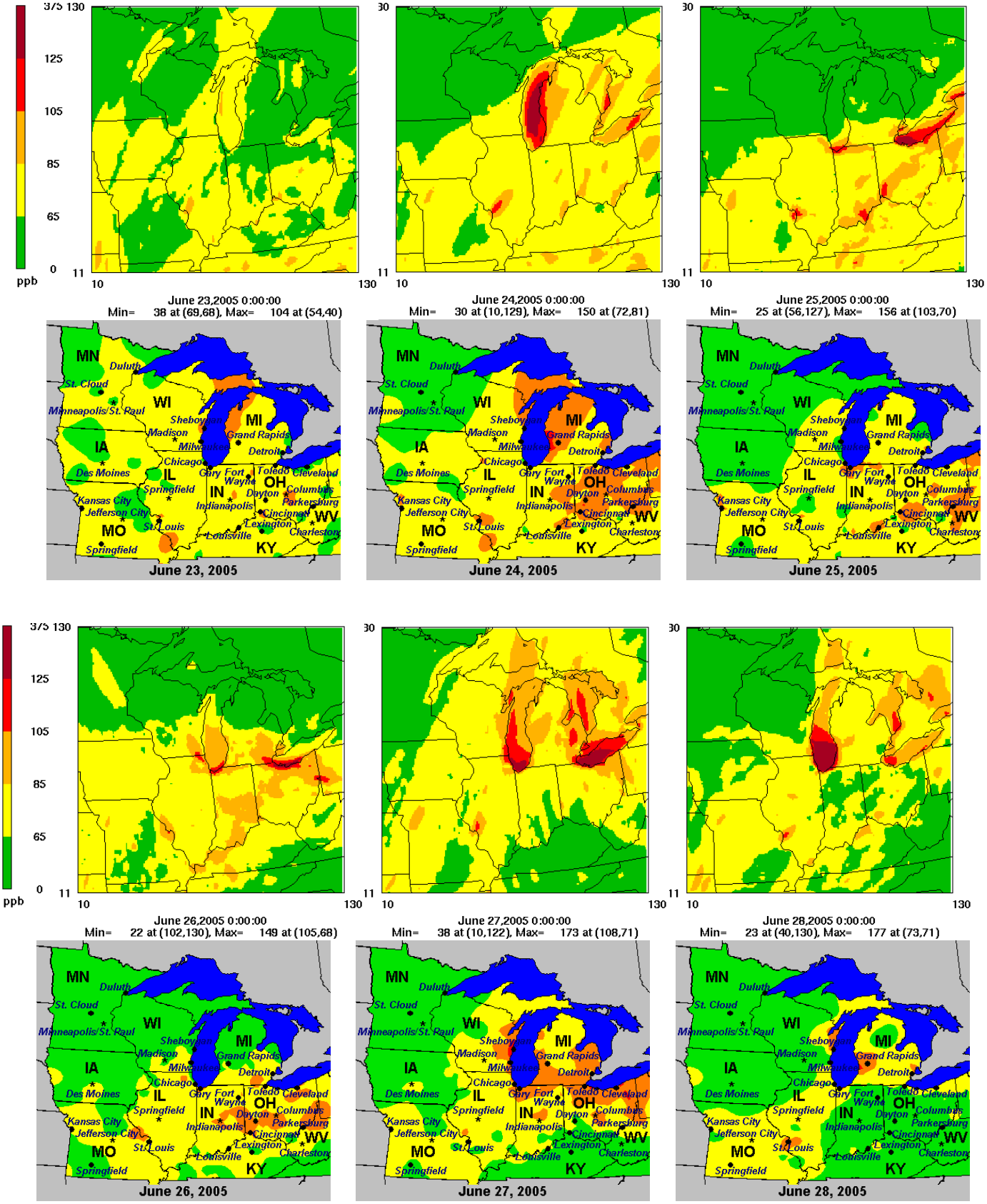


Figure 49b Modeled (top) v. monitored (bottom) 8-hour ozone concentrations: June 23– 28 2005

Standard model performance statistics were generated for the entire 12 km domain, and by day and by monitoring site. The domain-wide mean normalized bias for the 2005 base year is similar to that for the 2002 base year and is generally within 30% (see Figure 50).

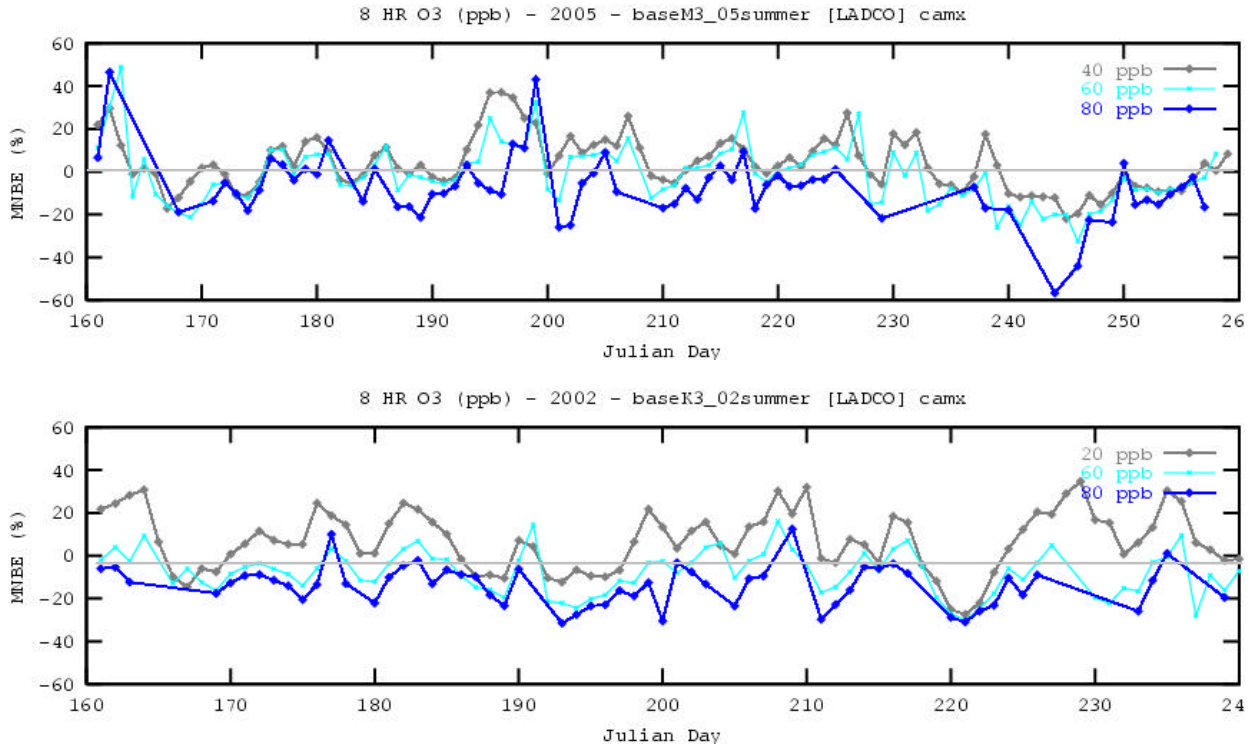


Figure 50. Mean bias for summer 2005 (Base M) and summer 2002 (Base K)

Station-average metrics (over the entire summer) are shown in Figure 51. The bias results further demonstrate the model's tendency to underestimate absolute ozone concentrations.

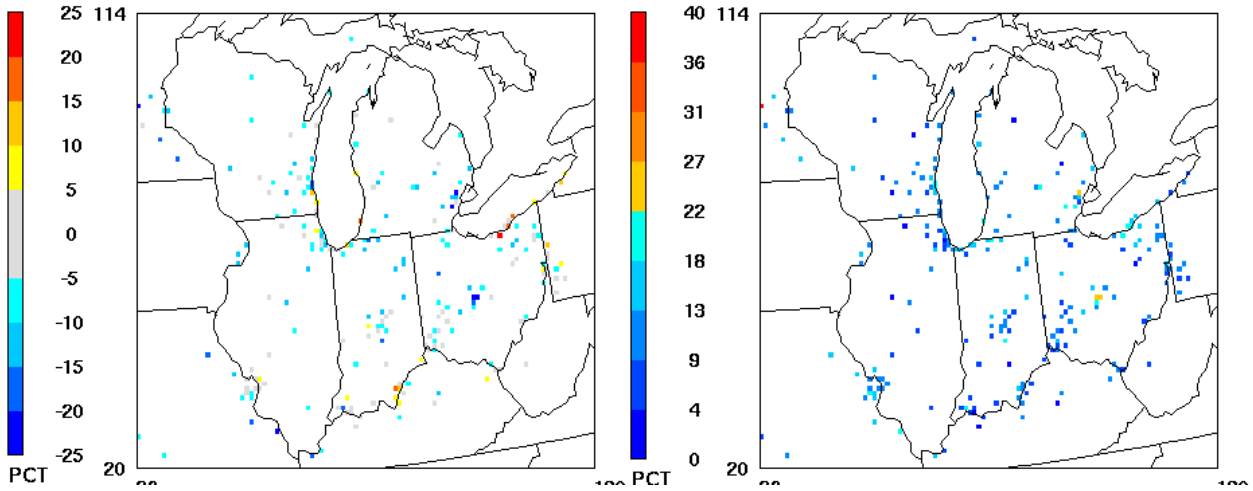


Figure 51. Mean bias (left) and gross error (right) for summer 2005

A limited 4 km ozone analysis was performed by LADCO to address the effect of grid spacing. For this modeling, 4 km grids were placed over Lake Michigan and the Detroit-Cleveland area (see Figure 52). Model inputs included 4 km emissions developed by LADCO (consistent with Base K/Round 4) and the 4 km meteorology developed by Alpine Geophysics.

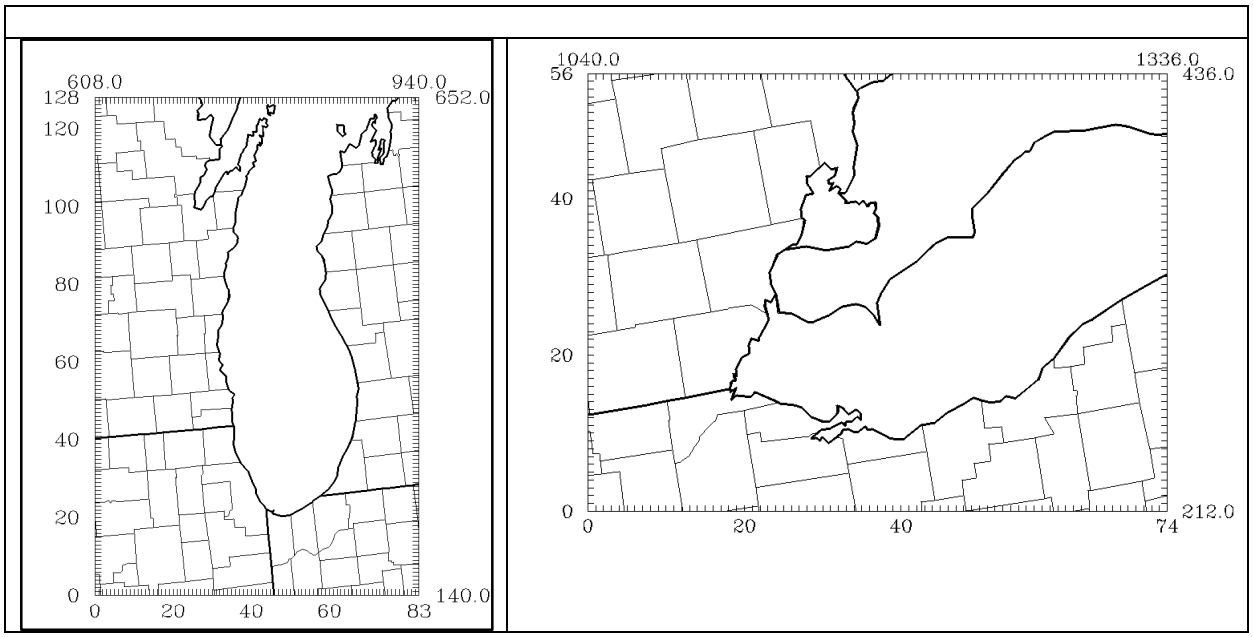


Figure 52. 4 km grids for Lake Michigan region and Detroit-Cleveland region

Hourly time series plots were prepared for several monitors (see Figure 53). The results are similar at 12 km and 4 km, with some site-by-site and day-by-day differences.

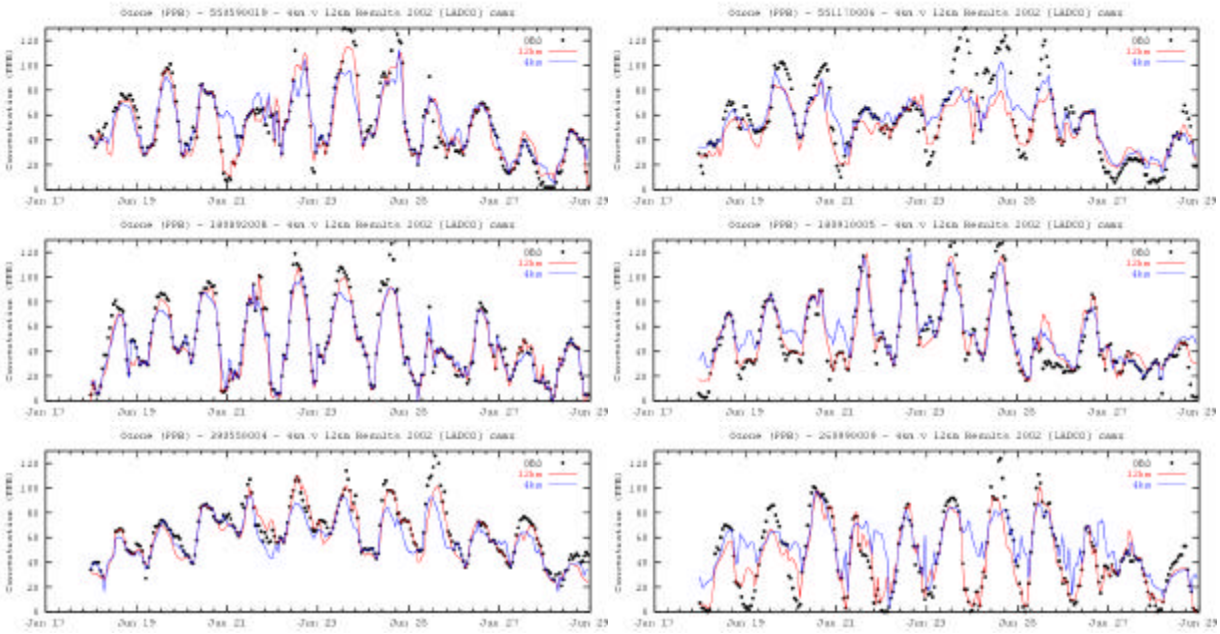
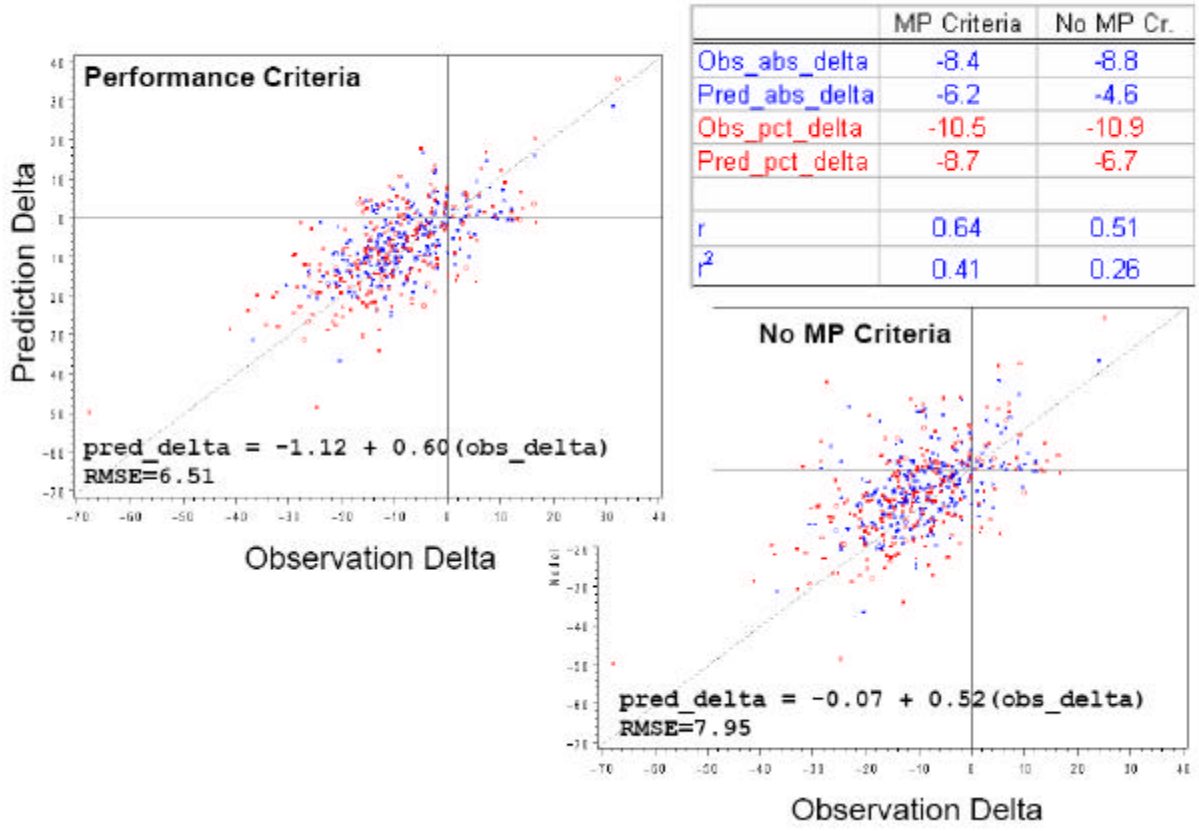


Figure 53. Ozone time series plots for 12 km and 4 km modeling (June 17-29, 2002)

An additional diagnostic analysis was performed to assess the response of the modeling system to changes in emissions (Baker and Kenski, 2007). Specifically, the 2002-to-2005 change in observed ozone concentrations was compared to the change in modeled ozone concentrations based on the 95th percentile(and above) concentration values for each monitor. This analysis was also done with the inclusion of model performance criteria which eliminated poorly performing days (i.e., error > 35%). The results show good agreement in the modeled and monitored ozone concentration changes (e.g., ozone improves by about 9-10 ppb between 2002 and 2005 according to the model and the measurements) – see Figure 54. This provides further support for using the model to develop ozone control strategies.



	MP Criteria	No MP Cr.
Obs_abs_delta	-8.4	-8.8
Pred_abs_delta	-6.2	-4.6
Obs_pct_delta	-10.5	-10.9
Pred_pct_delta	-8.7	-6.7
r	0.64	0.51
r^2	0.41	0.26

Figure 54. Comparison of change in predicted and observed ozone concentrations (2002 v. 2005)

$PM_{2.5}$: Time series plots of the monthly average mean bias and annual fractional bias for Base M and Base K are shown in Figure 55. As can be seen, Base M model performance for most species is fair (i.e., close to "no bias" throughout most of the year), with two main exceptions. First, the Base M and Base K results for organic carbon are poor, suggesting the need for more work on primary organic carbon emissions. Second, the Base M results for sulfate, while acceptable (i.e., bias values are within 35%), are not as good as the Base K results (e.g., noticeable underprediction during the summer months).

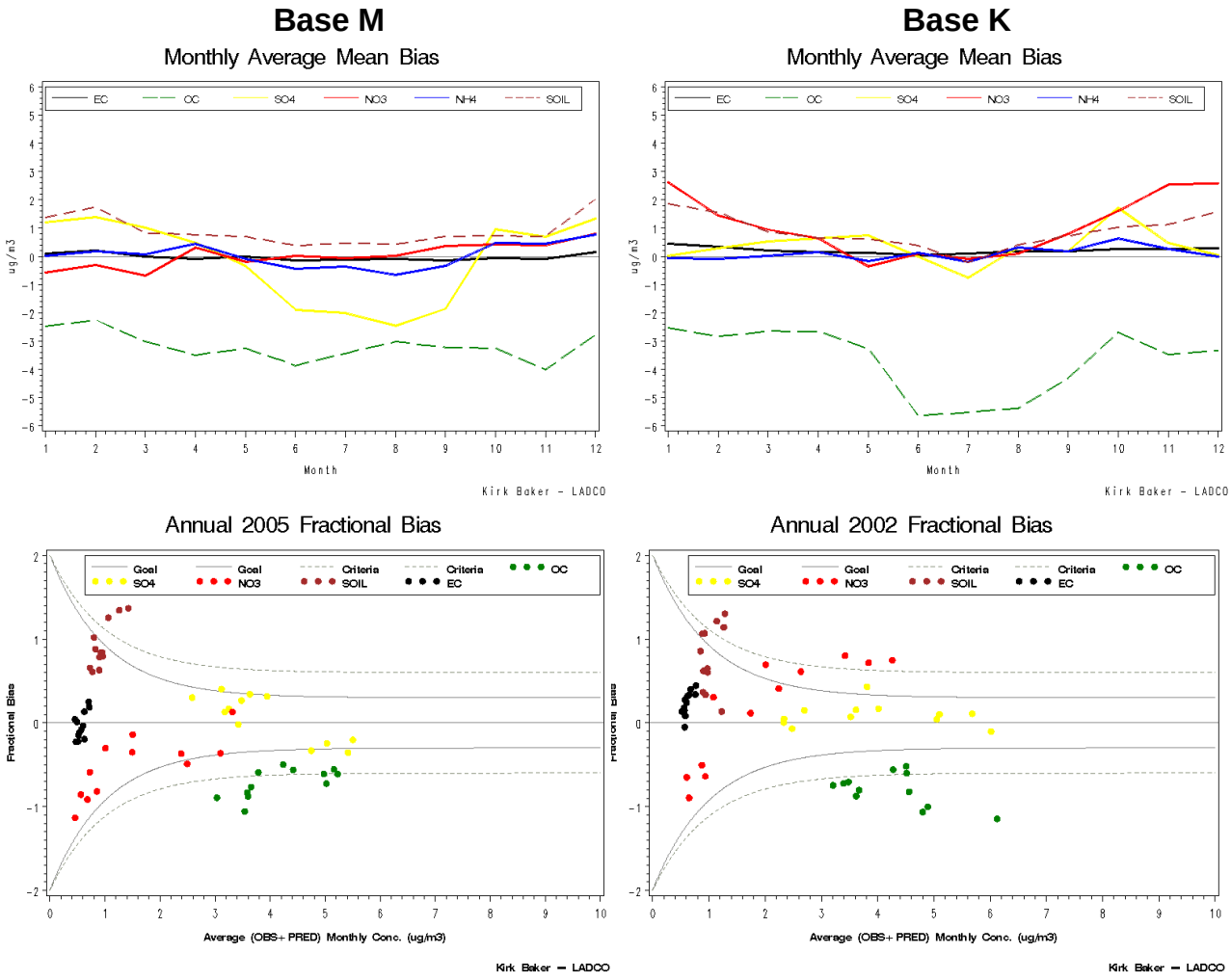


Figure 55. $PM_{2.5}$ Model performance - monthly average mean bias and annual fractional bias for Base M (left column) and Base K (right column)

Two analyses were undertaken to understand sulfate model performance for 2005:

- Assess Meteorological Influences: The MM5 model performance evaluation showed that rainfall is over-predicted by MM5 over most of the domain during the summer months (LADCO, 2007c). Because CAMx does not explicitly use the rainfall output by MM5, this may or may not result in over-prediction sulfate wet deposition (and under-prediction of sulfate concentrations). A sensitivity run was performed with no wet deposition for July, August, and September. The resulting model performance (see green line in Figure 56) showed a noticeable difference from the basecase (i.e., higher sulfate concentrations), and suggests that further evaluation of MM5 precipitation fields may be warranted.

- Assess Emissions Influences: The major contributor to sulfate concentrations in the region is SO2 emitted from EGUs. The basecase modeling inventory for EGUs is based on annual emissions, which were allocated to a typical weekday, Saturday, and Sunday by month using CEM-based temporal profiles. A sensitivity run was performed using day-specific emissions. The resulting model performance (see purple line in Figure 56) showed little difference from the basecase.

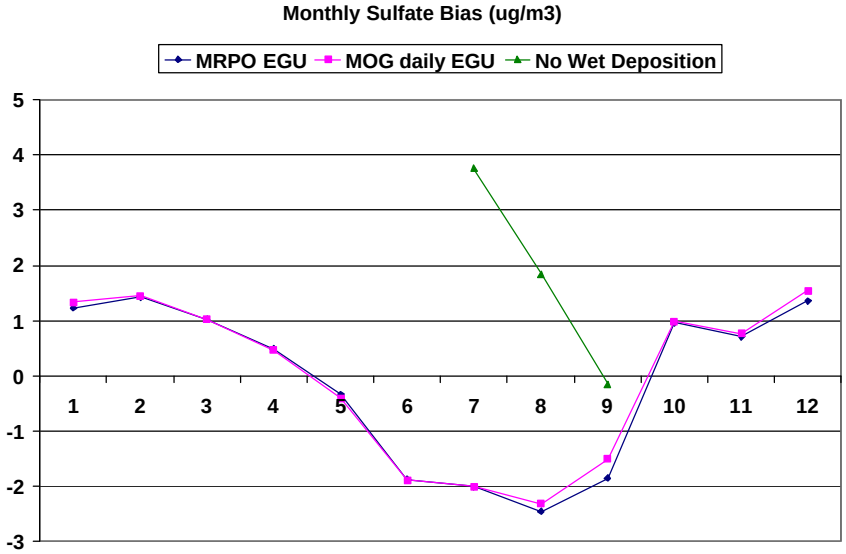


Figure 56. Monthly sulfate bias for Base M (MRPO EGU) v. two sensitivity analyses (Note: positive values indicate over-prediction, negative values indicate under-prediction)

To assess the effect of the wet deposition issue on future year modeled values, another sensitivity run was conducted with no wet deposition in Quarters 2-3 for the base year (2005) and 2018. The resulting future year values were only slightly different from the current base strategy run. In general, the future year values (without wet deposition) were a little higher (+0.15 ug/m^3 or less) in the Ohio Valley and a little lower (-.10 ug/m^3 of less) in the Great Lakes region. This sensitivity run provides a bound for sulfate wet deposition issue in terms of the attainment test, given that having no wet deposition is unrealistic. The results suggest that even with an improved wet deposition treatment, the Base M strategy results are not expected to change very much.

Time series plots of daily sulfate, nitrate, elemental carbon, and organic carbon concentrations for three Midwestern locations are presented in Figures 57 (2002) and 58 (2005). These results are consistent with the model performance statistics (i.e., good agreement for sulfates and nitrates and poor agreement [large underprediction] for organic carbon).

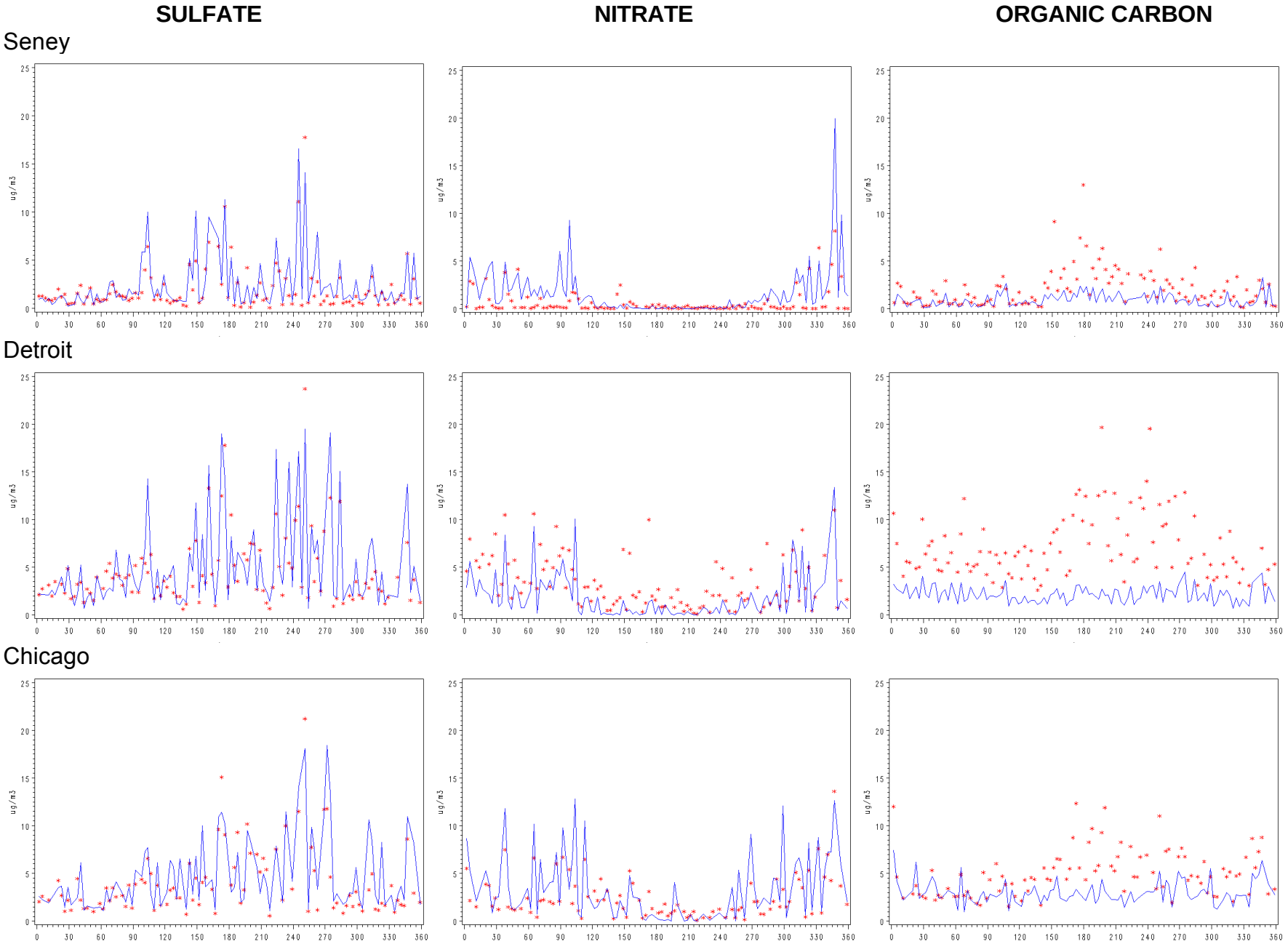
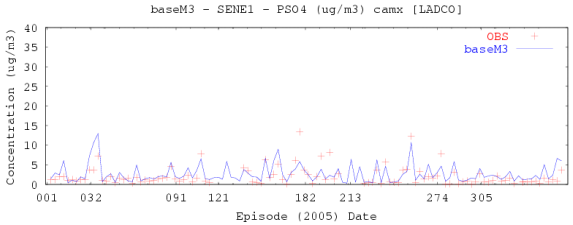
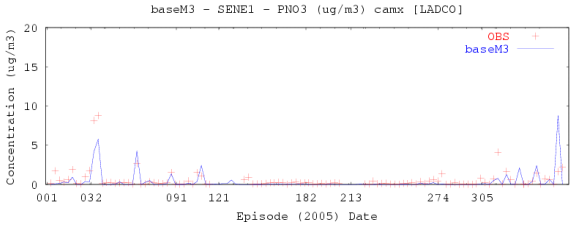


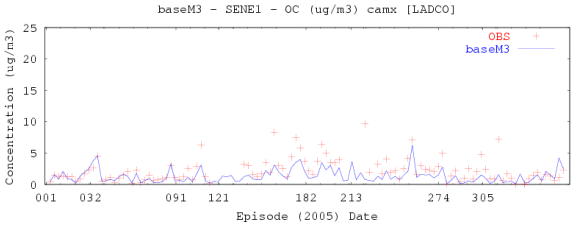
Figure 57. Time series of sulfate, nitrate, and organic carbon at three Midwest sites for 2005

SULFATE	NITRATE	ORGANIC CARBON

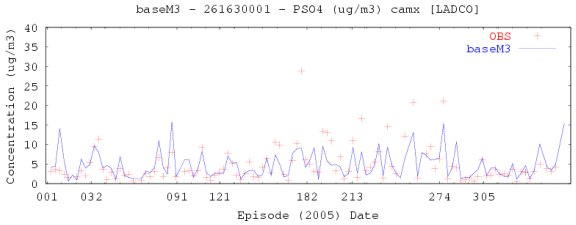
Seney

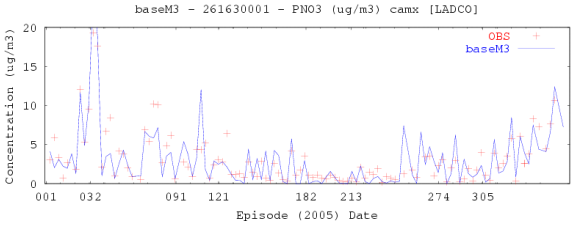


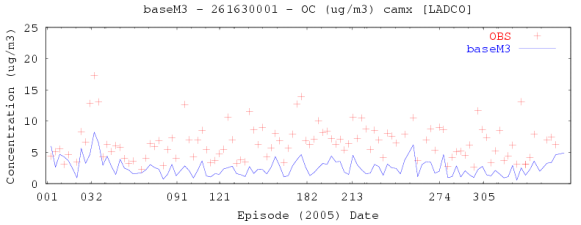




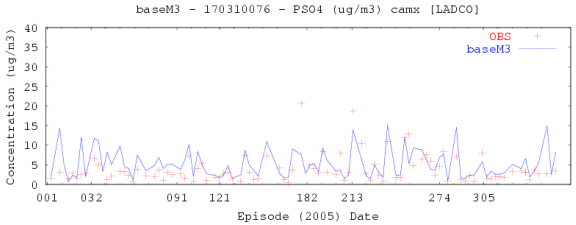
Detroit

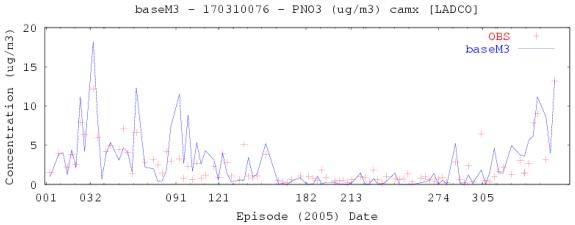






Chicago





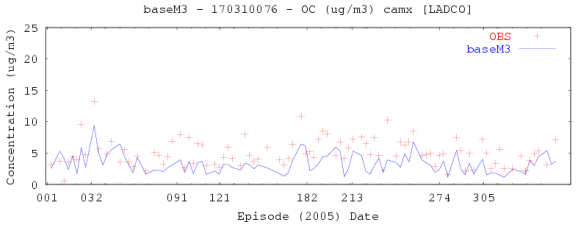


Figure 58. Time series of sulfate, nitrate, and organic carbon at three Midwest sites for 2005

In summary, model performance for ozone and $PM_{2.5}$ is generally acceptable and can be characterized as follows:

Ozone

- Good agreement between modeled and monitored concentration for higher concentration levels (> 60 ppb) – i.e., bias within 30%

- Regional modeled concentrations appear to be underestimated in the 2002 base year, but show better agreement (with monitored data) in the 2005 base year due to model and inventory improvements.

- Day-to-day and hour-to-hour variation in and spatial patterns of modeled concentrations are consistent with monitored data

- Model accurately simulates the change in monitored ozone concentrations due to reductions in precursor emissions.

$PM_{2.5}$

- Good agreement in the magnitude of fine particle mass, but some species are overestimated and some are underestimated (during periods of the year when it is important)
    - Sulfates: good agreement in the 2002 base year, but underestimated in the summer in the 2005 base year due probably to meteorological factors
    - Nitrates: slightly overestimated in the winter in the 2002 base year, but good agreement in the 2005 base year as a result of model and inventory improvements
    - Organic Carbon: grossly underestimated in the 2002 and 2005 base years due likely to missing primary organic carbon emissions and, possibly, other factors (e.g., grid resolution and model chemistry).

- Temporal variation and spatial patterns of modeled concentrations are consistent with monitored data

Several observations should be noted on the implications of these model performance findings on the attainment modeling presented in the following section. First, it has been demonstrated that model performance overall is acceptable and, thus, the model can be used for air quality planning purposes. Second, consistent with EPA guidance, the model is used in a relative sense to project future year values. EPA suggests that this approach "should reduce some of the uncertainty attendant with using absolute model predictions alone" (EPA, 2007a). Furthermore, the attainment modeling is supplemented by additional information to provide a weight of evidence determination.

Section 4.0 Attainment Demonstration for Ozone and $PM_{2./5}$

Air quality modeling and other information were used to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the NAAQS for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Traditionally, attainment demonstrations involved a "bright line" test in which a single modeled value was compared to the ambient standard. To provide a more robust assessment of expected future year air quality, EPA's modeling guidelines call for consideration of supplemental information. This section summarizes the results of the primary (guideline) modeling analysis and a weight of evidence determination based on the modeling results and other supplemental analyses.

4.1 Future Year Modeling Results

The purpose of the future year modeling is to assess the effectiveness of existing and possible additional control programs. The model was used in a relative sense to project future year values, which are then compared to the standard to determine attainment/nonattainment. Specifically, the modeling test consists of the following steps:

(1) Calculate base year design values: For ozone and $PM_{2.5}$, the base year design values were derived by averaging the three 3-year periods centered on the emissions base year:

2002 base year: 2000-2002, 2001-2003, and 2002-2004
2005 base year: 2003-2005, 2004-2006, and 2005-2007[11]

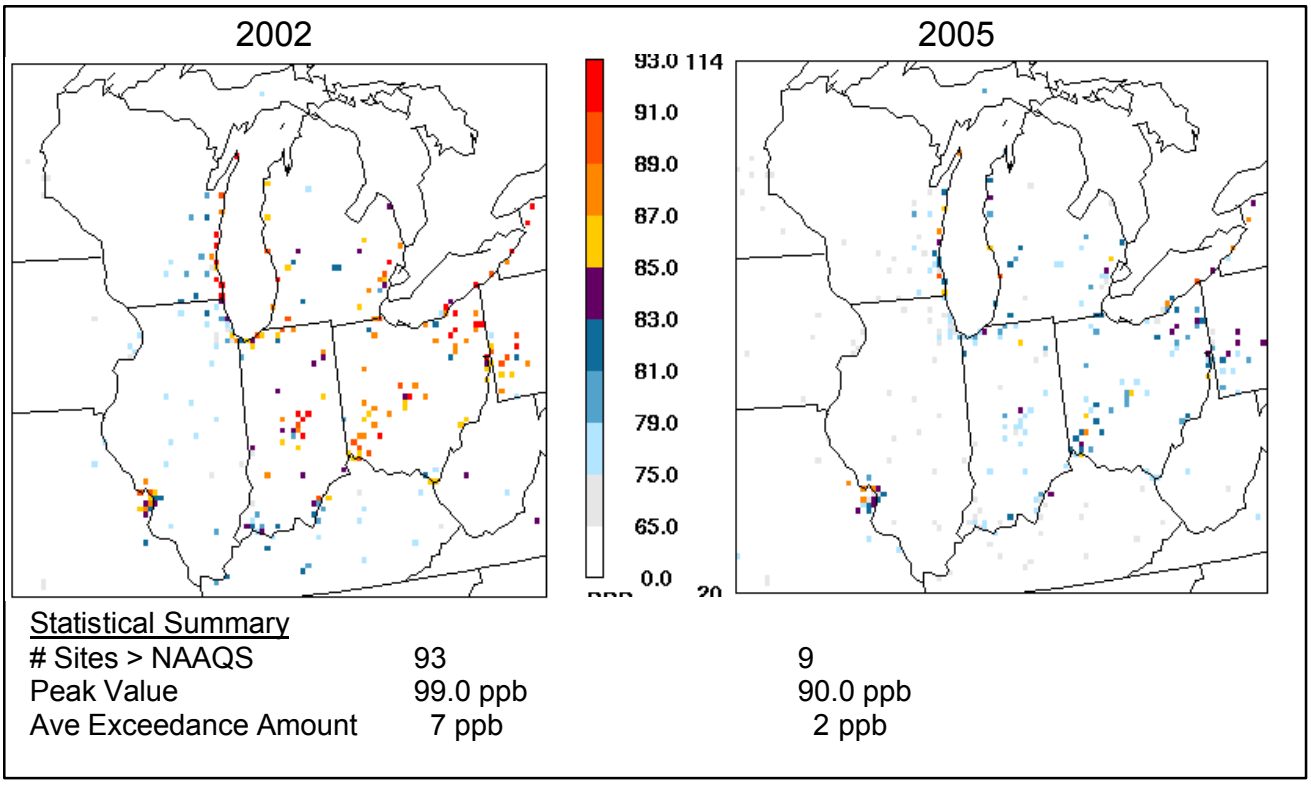
(2) Estimate the expected change in air quality: For each grid cell, a relative reduction factor (RRF) is calculated by taking the ratio of the future year and baseline modeling results.

(3) Calculate future year values: For each grid cell (with a monitor), the RRFs are multiplied by the base year design values to project the future year values

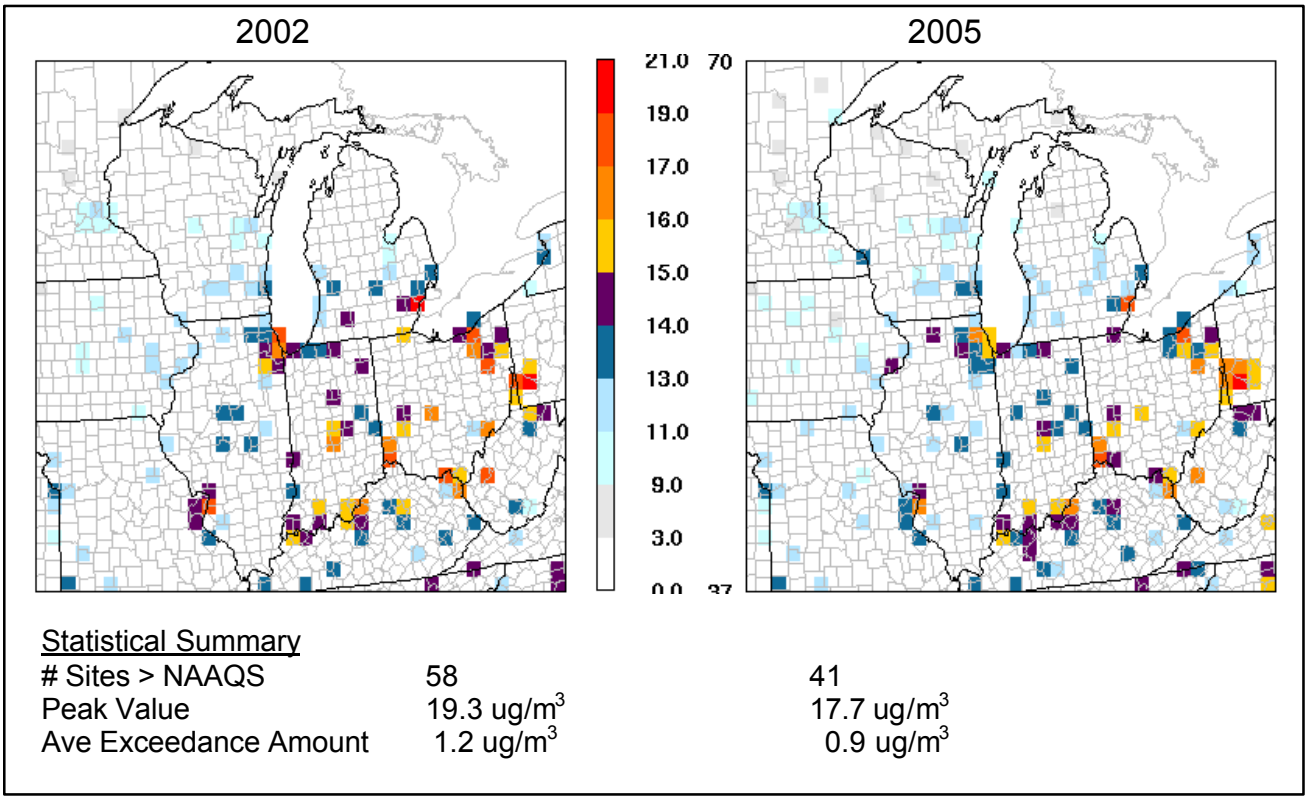
(4) Assess attainment: Future year values are compared to the NAAQS to assess attainment or nonattainment.

A comparison of the 2002 and 2005 base year design values for ozone and $PM_{2.5}$ is provided in Figure 59. In general, the figure shows that the 2005 base year design values are much lower than the 2002 base year design values, especially for ozone.

[11] A handful of source-oriented PM2.5 monitors in Illinois and Indiana were excluded from the annual attainment test, because these monitors are not to be used to judging attainment of the annual standard.



Statistical Summary		
# Sites > NAAQS	93	9
Peak Value	99.0 ppb	90.0 ppb
Ave Exceedance Amount	7 ppb	2 ppb



Statistical Summary		
# Sites > NAAQS	58	41
Peak Value	19.3 ug/m^3	17.7 ug/m^3
Ave Exceedance Amount	1.2 ug/m^3	0.9 ug/m^3

Figure 59. 2002 v. 2005 base year design values for ozone (top) and $PM_{2.5}$ (bottom)

Ozone results are provided for those grid cells with ozone monitors. The RRF calculation considers all nearby grid cells (i.e., 3x3 for 12 km modeling) and a threshold of 85 ppb. (If there were less than 10 days above this value, then the threshold was lowered until either there were 10 days or the threshold reached 70 ppb.) $PM_{2.5}$ results are provided for those grid cells with FRM ($PM_{2.5}$-mass) monitors. Spatial mapping was performed to extrapolate $PM_{2.5}$-speciation data from STN and IMPROVE sites to FRM sites. RRF values for $PM_{2.5}$ were derived as a function of quarter and chemical species.

Additional, hot-spot modeling will be performed by the states for certain $PM_{2.5}$ nonattainment areas (e.g., Detroit, Cleveland, and Granite City) to address primary emissions from local point sources which may not be adequately accounted for by the regional grid modeling. This modeling will consist of Gaussian dispersion modeling (e.g., AERMOD) performed in accordance with EPA's modeling guidance (see Section 5.3 of the April 2007 guidance document). Further analyses will need to be undertaken to determine how to best combine the regional modeling and the hot-spot modeling. This could mean some adjustment to the model results presented in this document to reflect better the regional component.

The ozone and $PM_{2.5}$ modeling results are provided in Appendix I for select monitors (high concentration sites) in the 5-state region for the following future years of interest: 2008 (ozone only), 2009, 2012, and 2018. (Note, RRF values for ozone, and for $PM_{2.5}$ by season and chemical species are also included in Appendix I for key monitoring sites.) A summary of the modeling results is provided in Table 9 (ozone) and Table 10 ($PM_{2.5}$), and spatial maps of the Base M future year concentrations are provided in Figures 60-62.

Table 9. Summary of Ozone Modeling Results									
Key Sites		**2008**		**2009**		**2012**		**2018**
		Round 5	Round 4	Round 5	Round 4	Round 5	Round 4	Round 5
Lake Michigan Area								
Chiwaukee	550590019	82.0	**93.0**	82.3	**92.0**	80.9	**90.3**	76.2
Racine	551010017	77.6	**85.9**	77.5	84.9	76.1	82.9	71.2
Milwaukee-Bayside	550190085	79.6	**85.4**	79.8	84.9	78.0	82.3	72.7
Harrington Beach	550890009	80.0	**86.7**	80.1	**85.4**	78.3	82.9	72.5
Manitowoc	550710007	81.3	80.3	80.8	78.9	78.6	76.3	72.5
Sheboygan	551170006	84.4	**90.0**	84.0	**88.9**	81.8	**86.4**	75.4
Kewaunee	550610002	78.9	82.5	78.1	81.0	75.9	79.1	69.9
Door County	550290004	84.8	83.6	83.9	81.8	81.5	79.3	74.7
Hammond	180892008	75.4	**86.9**	75.4	**86.6**	74.6	**86.3**	71.6
Whiting	180890030	77.0		77.0		76.2		73.1
Michigan City	180910005	74.2	**87.4**	73.9	**86.5**	72.5	**85.4**	68.1
Ogden Dunes	181270020	75.7	82.3	75.6	82.8	74.5	82.0	70.8
Holland	260050003	**85.6**	84.9	**85.3**	83.4	82.8	81.0	76.1
Jenison	261390005	77.9	78.7	77.1	77.6	74.5	75.5	68.7
Muskegon	261210039	80.8	82.7	80.5	81.5	78.0	79.4	71.9
Indianapolis Area								
Noblesville	189571001	78.0	**85.2**	78.1	83.7	75.6	82.0	68.7
Fortville	180590003	73.9	**85.1**	73.9	83.8	71.4	82.1	65.1
Fort B. Harrison	180970050	74.8	84.8	75.1	83.7	73.2	82.4	69.1
Detroit Area								
New Haven	260990009	82.7	**86.3**	81.4	**85.3**	80.2	83.5	76.1
Warren	260991003	82.5	84.3	81.3	83.3	80.7	81.9	77.6
Port Huron	261470005	79.0	80.5	77.5	79.1	75.5	77.0	70.9
Cleveland Area								
Ashtabula	390071001	84.9	84.7	83.4	82.7	81.0	80.2	75.1
Geauga	390550004	75.7	**90.3**	74.7	**88.8**	72.7	**86.2**	67.3
Eastlake	390850003	82.8	84.2	81.9	82.8	80.5	80.6	76.2
Akron	391530020	79.3	83.0	78.1	81.4	75.6	78.5	68.7
Cincinnati Area								
Wilmington	390271002	77.8	84.8	77.5	83.5	74.9	81.1	68.3
Sycamore	390610006	81.7	**85.4**	81.9	84.7	80.3	82.9	74.6
Lebanon	391650007	83.6	80.1	83.0	79.0	80.7	77.0	74.2
Columbus Area								
London	390970007	75.4	79.9	75.0	78.4	72.6	76.5	66.3
New Albany	390490029	82.4	84.1	81.8	82.6	79.6	80.2	73.0
Franklin	290490028	77.0	77.7	75.9	76.5	74.1	74.7	69.0
St. Louis Area								
W. Alton (MO)	291831002	82.4	**86.1**	81.0	**85.2**	78.6	84.0	74.9
Orchard (MO)	291831004	83.3	83.3	82.0	82.2	80.0	80.4	76.2
Sunset Hills (MO)	291890004	79.5	82.8	78.7	81.9	77.1	80.6	73.9
Arnold (MO)	290990012	78.7	78.4	77.2	77.4	75.6	75.8	72.0
Margaretta (MO)	295100086	79.8	84.0	79.3	83.4	77.9	82.5	74.4
Maryland Heights (MO)	291890014	84.5		83.4		81.7		78.1

Table 10. Summary of PM2.5 Modeling Results								
			2009		2012		2018	
County	**Site ID**	**Site**	**Round 5**	**Round4**	**Round 5**	**Round4**	**Round 5**	**Round4**
Cook	170310022	Chicago - Washington HS	14.1	14.8	14.0	14.6	13.9	14.4
Cook	170310052	Chicago - Mayfair	14.4	**15.8**	14.2	**15.5**	13.9	**15.0**
Cook	170310057	Chicago - Springfield	13.9	14.5	13.8	14.3	13.7	14.1
Cook	170310076	Chicago - Lawndale	13.8	14.5	13.7	14.3	13.6	14.1
Cook	170312001	Blue Island	13.7	14.5	13.6	14.3	13.4	14.1
Cook	170313301	Summit	14.2	14.8	14.0	14.6	13.9	14.4
Cook	170316005	Cicero	14.4	**15.3**	14.3	**15.1**	14.2	14.9
Madison	171191007	Granite City	**15.1**	**16.0**	14.9	**15.8**	14.3	**15.5**
St. Clair	171630010	E. St. Louis	14.1	14.9	13.9	14.7	13.4	14.5
Clark	180190005	Jeffersonville	13.8	**15.5**	13.7	**15.0**	13.4	14.4
Dubois	180372001	Jasper	12.4	13.8	12.2	13.5	11.8	13.0
Lake	180890031	Gary	13.0		12.8		12.4	
Marion	180970078	Indy-Washington Park	12.8	14.5	12.6	14.2	12.0	13.7
Marion	180970083	Indy- Michigan Street	13.4	14.8	13.1	14.9	12.6	14.0
Wayne	261630001	Allen Park	13.0	14.5	12.8	14.1	12.4	13.3
Wayne	261630015	Southwest HS	14.2	**15.8**	13.9	**15.3**	13.5	14.4
Wayne	261630016	Linwood	13.1	14.1	12.8	13.7	12.5	13.0
Wayne	261630033	Dearborn	**15.8**	**17.7**	**15.5**	**17.1**	**15.1**	**16.1**
Wayne	261630036	Wyandotte	13.1	**15.1**	12.8	14.7	12.5	13.9
Butler	390170003	Middleton	13.5	14.2	13.2	13.7	12.8	13.1
Butler	390170016	Fairfield	13.1	13.5	12.9	12.9	12.5	12.2
Cuyahoga	390350027	Cleveland-28th Street	13.5	14.4	13.2	13.8	12.7	12.9
Cuyahoga	390350038	Cleveland-St. Tikhon	**15.2**	**16.1**	14.8	**15.4**	14.3	14.4
Cuyahoga	390350045	Cleveland-Broadway	14.4	14.6	14.0	14.0	13.5	13.1
Cuyahoga	390350060	Cleveland-GT Craig	15.0	**15.3**	14.6	14.7	14.1	13.7
Cuyahoga	390350065	Newburg Hts - Harvard Ave	14.0	14.1	13.6	13.5	13.1	12.6
Franklin	390490024	Columbus - Fairgrounds	12.9	14.6	12.6	14.0	12.0	13.0
Franklin	390490025	Columbus - Ann Street	12.7	14.1	12.4	13.5	11.9	12.5
Franklin	390490081	Columbus - Maple Canyon	11.7	14.0	11.4	13.4	10.9	12.5
Hamilton	390610014	Cincinnati - Seymour	14.5	**15.5**	14.3	14.8	13.8	14.0
Hamilton	390610040	Cincinnati - Taft Ave	12.8	13.6	12.6	13.0	12.2	12.3
Hamilton	390610042	Cincinnati - 8th Ave	14.0	14.6	13.8	14.0	13.4	13.2
Hamilton	390610043	Sharonville	12.9	13.6	12.7	13.0	12.3	12.2
Hamilton	390617001	Norwood	13.4	14.2	13.2	13.6	12.8	12.8
Hamilton	390618001	St. Bernard	14.7	**15.2**	14.4	14.6	14.0	13.8
Jefferson	390810016	Steubenville	12.8	**16.3**	12.5	**15.9**	12.7	**16.2**
Jefferson	390811001	Mingo Junction	13.5	**15.5**	13.2	**15.0**	13.4	**15.3**
Lawrence	390870010	Ironton	12.8	14.2	12.5	13.7	12.3	13.2
Montgomery	391130032	Dayton	13.2	13.7	12.9	13.2	12.4	12.3
Scioto	391450013	New Boston	12.1	**15.4**	11.9	14.8	11.6	14.2
Stark	391510017	Canton - Dueber	14.0	**15.0**	13.6	14.3	13.3	13.6
Stark	391510020	Canton - Market	12.6	13.6	12.3	13.0	11.9	12.2
Summit	391530017	Akron - Brittain	13.0	14.4	12.7	13.6	12.3	12.9
Summit	391530023	Akron - W. Exchange	12.3	13.6	12.0	13.0	11.5	12.2

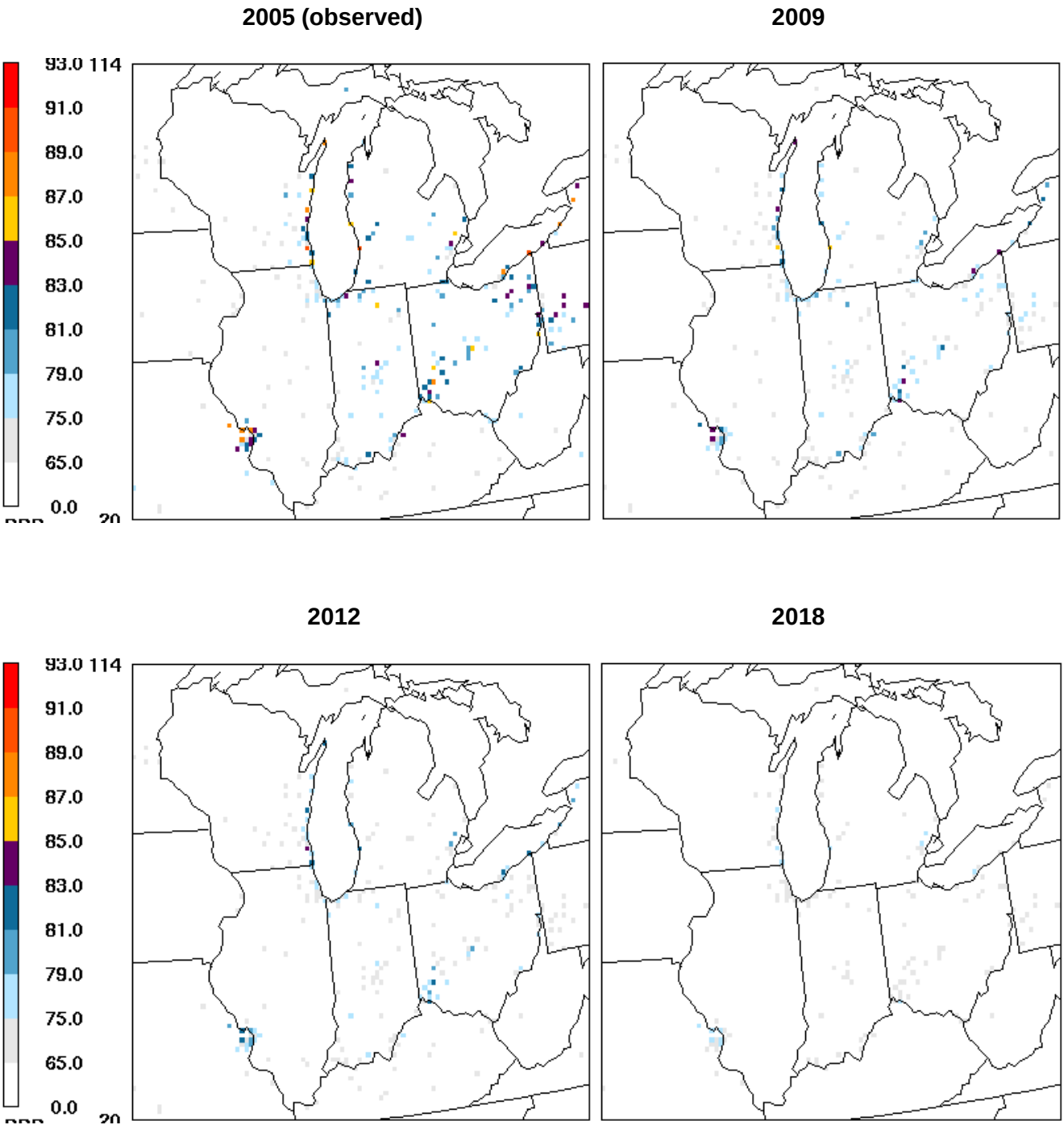


Figure 60. Observed base year and projected future year design values for ozone – Base M

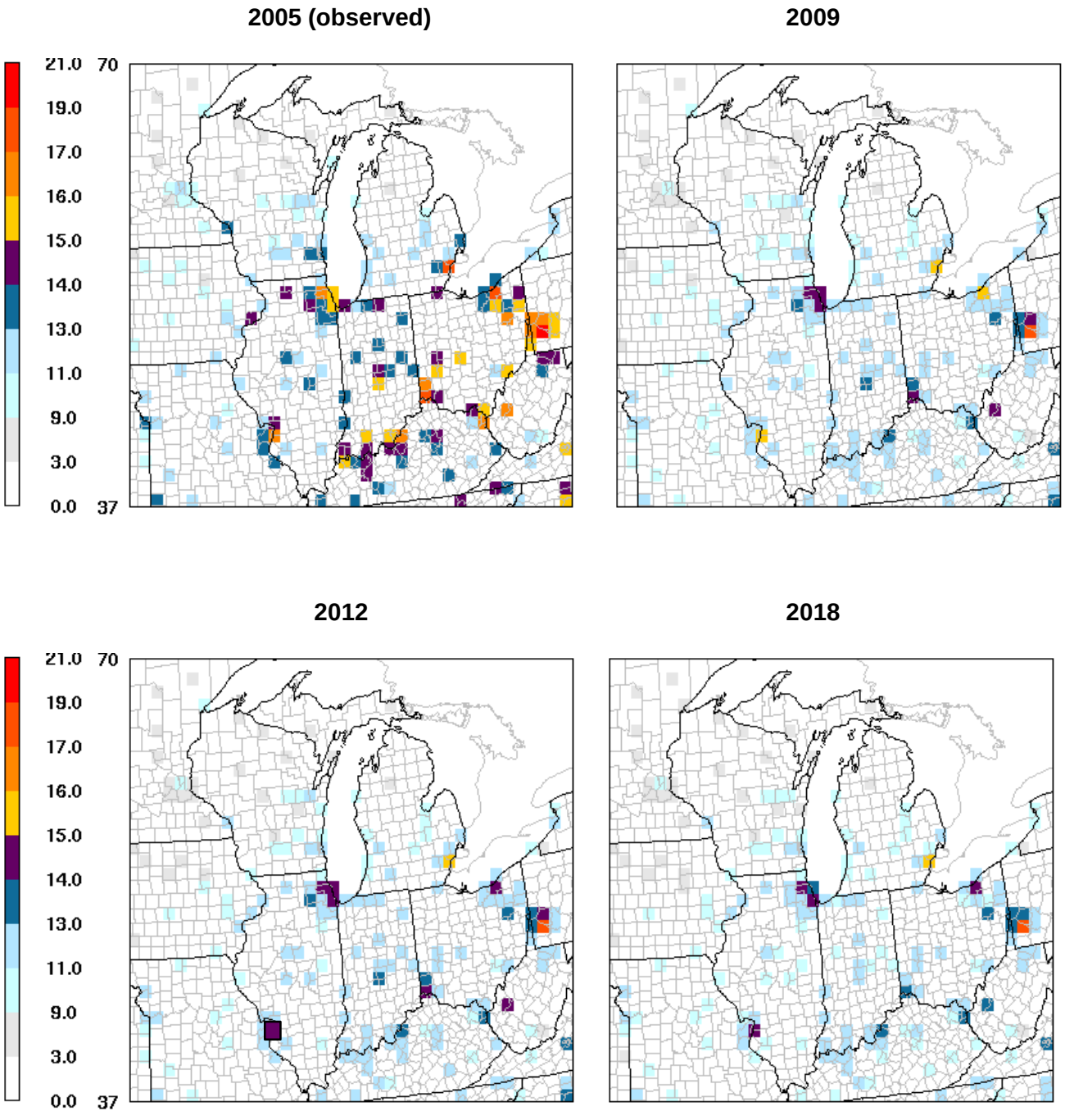


Figure 61. Observed base year and projected future year design values for $PM_{2.5}$ (annual average)–Base M

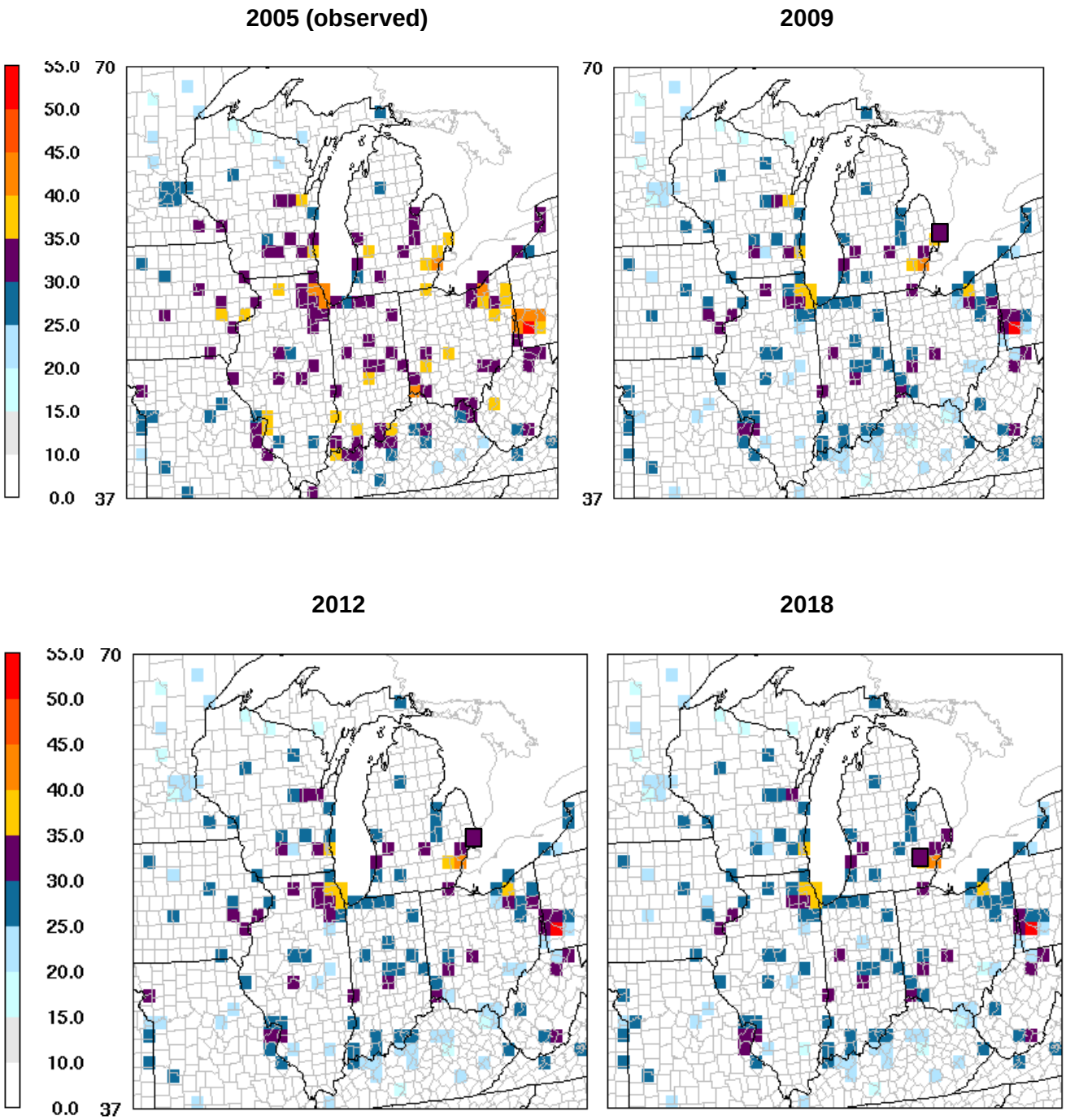


Figure 62. Observed base year and projected future year design values for $PM_{2.5}$ (24-hr average)-Base M

The number of monitors with design values above the standard are as follows:

Table 11. Number of sites above standard

Ozone (8 hour: 85 ppb)										
State	2002	2005		2009			2012			2018	
	BaseK	Base M		BaseK	Base M		BaseK	Base M		BaseK	Base M
IL	3	0		0	0		0	0		0	0
IN	22	0		0	0		0	0		0	0
MI	15	3		1	1		0	0		0	0
OH	40	4		1	0		1	0		0	0
WI	13	2		4	0		3	0		1	0
Total	93	9		6	1		4	0		1	0
PM2.5 (Annual: 15 ug/m^3)										
State	2002	2005		2009			2012			2018	
	BaseK	Base M		BaseK	Base M		BaseK	Base M		BaseK	Base M
IL	11	7		3	1		3	0		2	0
IN	10	6		1	0		1	0		0	0
MI	6	2		3	1		2	1		0	0
OH	31	26		7	1		4	0		1	1
WI	0	0		0	0		0	0		2	0
Total	58	41		14	3		10	1		5	1

The modeling results above reflect the "base" controls identified in Section 3.6, with EGU emissions based on IPM modeling (i.e., Round 4 – IPM2.1.9, and Round 5 – IPM3.0). In addition, two sets of alternative future year EGU emissions were examined in Round 5. First, alternative control assumptions were provided for several facilities by the states (i.e., "will do" and "may do" scenarios). In general, these scenarios produced a small change in future year ozone and $PM_{2.5}$ concentrations (i.e., about 0.1 ug/m^3 for $PM_{2.5}$ and 0.1-0.2 ppb for ozone). Second, EPA suggested adjustments to the 2010 IPM emissions to reflect 2009 conditions. The revised (2009) SO2 emissions represent a 5-6% increase in domainwide SO2 emissions. The increased SO2 emissions result in slightly greater annual average $PM_{2.5}$ concentrations (on the order of 0.1 – 0.2 ug/m^3), but do not produce any new residual nonattainment areas.

The limited 4 km ozone modeling (based on Base K) performed by LADCO included a future year analysis for 2009. The figure below shows the 2009 values with 12 km and 4 km grid spacing for the LADCO modeling and similar modeling conducted by a stakeholder group (Midwest Ozone Group).

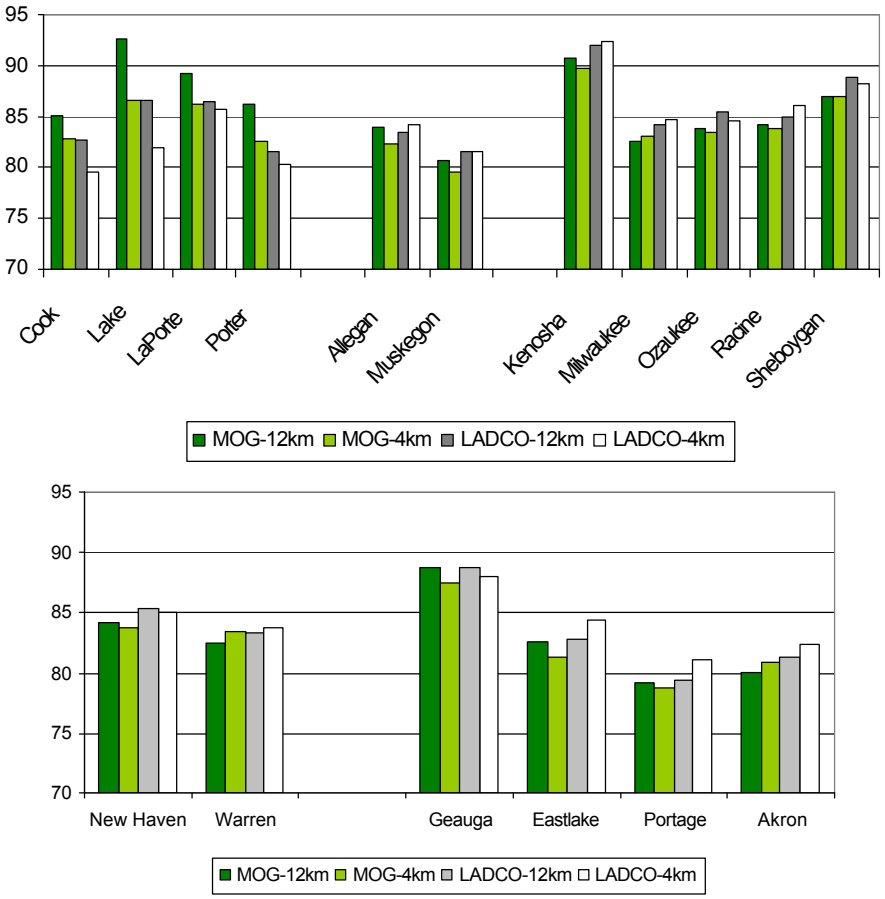


Figure 63. Future year (2009) values for Lake Michigan area (top) and Detroit-Cleveland region (bottom)

These results show that the 12 km and 4 km values are similar, with the most notable changes in northwestern Indiana and northeastern Illinois (e.g., 4 km values are as much as 4 ppb lower than 12 km values). The differences in the southern part of the Lake Michigan area are plausible, given the tight emissions gradient there (i.e., finer grid resolution appears to provide more appropriate representation).

In light of these findings, 12 km grid spacing can continue to be used for ozone modeling, but the Base K/Round 4 results for northwestern Indiana/northeastern Illinois should be viewed with caution (i.e., probably 1 – 4 ppb too high).

In summary, the ozone modeling provides the following information for the nonattainment areas in the region (see Table 12):

Table 12. Ozone Nonattainment Areas in the LADCO Region (as of December 31, 2007)

Area Name	Category	Number of Counties	Attainment Deadline
Detroit-Ann Arbor, MI	Marginal	8	2007
Chicago-Gary-Lake County, IL-IN	Moderate	10	2010
Cleveland-Akron-Lorain, OH	Moderate	8	2010
Milwaukee-Racine, WI	Moderate	6	2010
Sheboygan, WI	Moderate	1	2010
St Louis, MO-IL	Moderate	4	2010
Allegan Co, MI	Subpart 1	1	2009
Cincinnati-Hamilton, OH-KY-IN	Subpart 1	6	2009
Columbus, OH	Subpart 1	6	2009
Door Co, WI	Subpart 1	1	2009
Kewaunee Co, WI	Subpart 1	1	2009
Manitowoc Co, WI	Subpart 1	1	2009
		53	

Marginal Areas (2007 attainment date): No modeling was conducted for the 2006 SIP planning year. Rather, 2005 – 2007 air quality data are available to determine attainment.

Basic (Subpart 1) Areas (2009 attainment date): The modeling results for the 2008 SIP planning year show:

- Base K: all areas in attainment, except Cincinnati and Indianapolis
- Base M: all areas in attainment, except Holland (Allegan County)

Moderate Areas (2010 attainment date): The modeling results for the 2009 SIP planning year show:

- Base K: all areas still in nonattainment
- Base M: all areas in attainment

The $PM_{2.5}$ modeling results show:

- Base K: all areas in attainment, except for Chicago, Cincinnati, Cleveland, Detroit, Granite City (IL), Louisville, Portsmouth (OH), and Steubenville
- Base M: all areas in attainment, except for Cleveland, Detroit, and Granite City (IL)

With respect to the new lower 8-hour ozone standard, the modeling about 30 sites in 2012 and 5 sites in 2018 with design values greater than 75 ppb. With respect to the new lower 24-hour $PM_{2.5}$ standard, the modeling shows 13 sites in 2012 and 10 in 2018 with design values greater than 35 ug/m^3.

4.2 Supplemental Analyses

EPA's modeling guidelines recommend that attainment demonstrations consist of a primary (guideline) modeling analysis and supplemental analyses. Three basic types of supplemental analyses are recommended:

- additional modeling
- analyses of trends in ambient air quality and emissions, and
- observational models and diagnostic analyses

Furthermore, according to EPA's guidelines, if the future year modeled values are "close" to the standard (i.e., 82 – 87 ppb for ozone and 14.5 – 15.5 ug/m^3 for $PM_{2.5}$), then the results of the primary modeling should be reviewed along with the supplemental information in a "weight of evidence" assessment of whether each area is likely to achieve timely attainment.

A WOE determination for ozone and $PM_{2.5}$ is provided in the following sections. Special attention is given to the following areas with future year modeled values that exceed or are "close" to the ambient standard (see Appendix I):

Ozone	**PM2.5**
Lake Michigan area	Chicago, IL
Cleveland, OH	Cleveland, OH
Cincinnati, OH	Cincinnati, OH
	Granite City, IL
	Detroit, MI

4.3 Weight-of-Evidence Determination for Ozone

The WOE determination for ozone consists of the primary modeling and other supplemental analyses (some of which were discussed in Section 2). A summary of this information is provided below.

Primary (Guideline) Modeling: The guideline modeling is presented in Section 4.1. Key findings from this modeling include:

- Base M regional modeling shows attainment by 2008 and 2009 at all sites, except Holland (MI), and attainment at all sites by 2012.

- Base K modeling results reflect generally higher future year values, and show more sites in nonattainment compared to the Base M modeling. The difference in the two modeling analyses is due mostly to lower base year design values in Base M.

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for ozone should reflect a weight-of-evidence approach, with consideration of monitoring based information.

- Base M modeling also shows that the proposed lower 8-hour standard will not be met at many sites, even by 2018, with existing controls.

Additional Modeling: Four additional modeling analyses were considered: (1) re-examination of the primary modeling to estimate attainment probabilities, (2) remodeling with different assumptions, (3) an unmonitored area analysis, and (4) EPA's latest regional ozone modeling. Each of these analyses is described below.

First, the primary modeling results (which were initially processed using EPA's attainment test) were re-examined to estimate the probability of attaining the ozone standard (Lopez, 2007, and LADCO, 2008b). Seven estimates of future year ozone concentrations were calculated based on model-based RRFs and appropriate monitor-based concentrations for each year between 2001 and 2007. RRF values for 2001, 2003, 2004, 2006, and 2007 were derived based on the 2002 and 2005 modeling results. Monitor-based concentrations reflect 4th high values, design values, or average of three design values centered on the year in question. The probability of attainment was determined as the percentage of these seven estimates below the standard. The results indicate that sites in the Lake Michigan area (Chiwaukee, Sheboygan, Holland, Muskegon), Cleveland (Ashtabula), and St. Louis (W Alton) have a fairly low probability of attainment by 2009 (i.e., about 50% or less).

Second, the primary modeling analysis was redone with different types of assumptions for calculating base year design values (i.e., using the 3-year period centered on base year, and using the highest 3-year period that includes the base year), and for calculating RRFs (i.e., using all days with base year modeled value > 70 ppb, and using all days with base year modeled value > 85 ppb, with at least 10 days and "acceptable" model performance). The results for several high concentration sites are presented in Tables 13a and 13b for 2009. The different modeling assumptions produce eight estimates of future year ozone concentrations. The highest estimates are associated with base year design values representing the 3-year average for 2001-2003, and the lowest estimates are associated with base year design values representing the 3-year average 2004-2006. The different RRF approaches produce little change in future year ozone concentrations. This suggests that future year concentration estimates are most sensitive to the choice of the base year and the methodology used to derive the base year design values.

Third, EPA's modeling guidelines recommend that an "unmonitored area analysis" be included as a supplemental analysis, particularly in nonattainment areas where the monitoring network just meets or minimally exceeds the size of the network required to report data to EPA's Air Quality System. The purpose of this analysis is to identify areas where future year values are predicted to be greater than the NAAQS.

Based on examination of the spatial plots in Figures 49a and 49b, the most notable areas of high modeled ozone concentrations are over the Great Lakes. Over-water monitoring, however, is not required by EPA[12]. A cursory analysis of unmonitored areas for ozone was performed by LADCO using an earlier version of the 2002 base year modeling (i.e, Base I) (Baker, 2005). Base year and future year "observed" values were derived for unmonitored grid cells using the absolute modeled concentrations (in all grid cells) and the observed values (in monitored grid cells). A spatial map of the estimated 2009 values is provided in Figure 64. As can be seen, there are very few (over land) grid cells where additional monitors may be desirable. This indicates that the current modeling analysis, which focuses on monitored locations, is addressing areas of high ozone throughout the region.

[12] Air quality measurements over Lake Michigan were collected by LADCO previously to understand ozone transport in the area (see, for example, Figure 5). Due to cut-backs in USEPA funding, however, these measurements were discontinued in 2003.

Table 13a. Primary and Additional Ozone Modeling Results – Lake Michigan and Cleveland Areas (2009)

2009 Modeling Results		Lake Michigan Area								Cleveland Area		
		Chiwaukee	Harr.Beach	Sheboygan	DoorCounty	Holland	Hammond	MichiganCity		Ashtabula	Geauga	Eastlake
		550590019	550890009	551170006	550290004	260050003	180892008	180910005		390071001	390550004	390850003
Attainment Test (based on EPA guidance-2002 baseyear)												
Base Year Design Value (average of three 3-year periods)		*98.3*	*93.0*	*97.0*	*91.0*	*94.0*	*88.3*	*90.3*		*95.7*	*99.0*	*92.7*
RRF (all days > 85 ppb, or at least 10 days)		0.935	0.918	0.916	0.899	0.888	0.980	0.958		0.865	0.897	0.894
Future Year Design Value		**91.9**	**85.4**	**88.9**	**81.8**	83.5	**86.5**	**86.5**		82.8	**88.8**	82.9
Attainment Test (based on EPA guidance-2005 baseyear)												
Base Year Design Value (average of three 3-year periods)		*84.7*	*83.3*	*88.0*	*88.7*	*90.0*	*77.7*	*77.0*		*89.0*	*79.3*	*86.3*
RRF (all days > 85 ppb, or at least 10 days)		0.972	0.961	0.955	0.946	0.948	0.971	0.960		0.937	0.942	0.949
Future Year Design Value		82.3	80.1	84.0	83.9	**85.3**	75.4	73.9		83.4	74.7	81.9
Weight of Evidence (alternative approaches-2002baseyear)												
Alt 1 - Base Year Des. Value (3-year period centered on 2002)		*101.0*	*98.0*	*100.0*	*94.0*	*97.0*	*90.0*	*93.0*		*99.0*	*103.0*	*95.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2002)		*101.0*	*98.0*	*100.0*	*94.0*	*97.0*	*92.0*	*93.0*		*99.0*	*103*	*95.0*
RRF (all days > 85 ppb, or at least 10 days)		0.935	0.918	0.916	0.899	0.888	0.980	0.958		0.865	0.897	0.894
Alt 1 - Future Year Projected Value		**94.4**	**90.0**	**91.6**	84.5	**86.1**	**88.2**	**89.1**		**85.6**	**92.4**	84.9
Alt 2 - Future Year Projected Value		**94.4**	**90.0**	**91.6**	84.5	**86.1**	**90.2**	**89.1**		**85.6**	**92.4**	84.9
Alt 1 - RRF (all days > 70 ppb)		0.933	0.918	0.912	0.907	0.893	0.969	0.947		0.876	0.907	0.900
Alt 1 - Future Year Projected Value		**94.2**	**90.0**	**91.2**	**85.3**	**86.6**	**87.2**	**88.1**		**86.7**	**93.4**	**85.5**
Alt 2 - Future Year Projected Value		**94.2**	**90.0**	**91.2**	**85.3**	**86.6**	**89.1**	**88.1**		**86.7**	**93.4**	**85.5**
Alt 2 - RRF (all days > 85 ppb, or at least 10 days; with acceptable model performance)		0.945	0.904	0.910	0.904	0.887	0.976	0.964		0.866	0.896	0.894
Alt 1 - Future Year Projected Value		**95.4**	**88.6**	**91.0**	**85.0**	**86.0**	**87.8**	**89.7**		**85.7**	**92.3**	84.9
Alt 2 - Future Year Projected Value		**95.4**	**88.6**	**91.0**	**85.0**	**86.0**	**89.8**	**89.7**		**85.7**	**92.3**	84.9
Weight of Evidence (alternative approaches-2005baseyear)												
Alt 1 - Base Year Des. Value (3-year period centered on 2005)		*83.0*	*79.0*	*86.0*	*86.0*	*88.0*	*76.0*	*76.0*		*86.0*	*77.0*	*86.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2005)		*86.0*	*88.0*	*89.0*	*90.0*	*93.0*	*79.0*	*78.0*		*91.0*	*86.0*	*89.0*
Alt 1 - Future Year Projected Value		80.7	75.9	82.1	81.4	83.4	73.8	73.0		80.6	72.5	81.6
Alt 2 - Future Year Projected Value		83.6	84.6	**85.0**	**85.1**	**88.2**	76.7	74.9		**85.3**	81.0	84.5

Table 13b. Primary and Additional Ozone Modeling Results – Cincinnati, Columbus, St. Louis, Indianapolis, and Detroit (2009)

2009 Modeling Results	Cincinnati Area			Columbus	St. Louis Area		Indianapolis Area		Detroit Area
	Wilmington	Lebanon	Sycamore	NewAlbany	W. Alton	OrchardFarm	Noblesville	Fortville	New Haven
	390271002	39165007	390610006	390490029	291831002	291831004	180571001	18059003	260990009
Attainment Test (based on EPA guidance-2002 baseyear)									
Base Year Design Value (average of three 3-year periods)	*94.3*	*90.7*	*90.7*	*94.0*	*90.0*	*90.0*	*93.7*	*91.3*	*92.3*
RRF (all days > 85 ppb, or at least 10 days)	0.885	0.908	0.938	0.888	0.947	0.914	0.894	0.918	0.924
Future Year Design Value	83.5	82.4	**85.1**	83.5	**85.2**	82.3	83.8	83.8	**85.3**
Attainment Test (based on EPA guidance-2005 baseyear)									
Base Year Design Value (average of three 3-year periods)	*82.3*	*87.7*	*84.3*	*86.3*	*86.3*	*87.0*	*83.3*	*78.7*	*86.0*
RRF (all days > 85 ppb, or at least 10 days)	0.941	0.947	0.967	0.947	0.938	0.942	0.945	0.947	0.947
Future Year Design Value	77.4	83.1	81.5	81.7	80.9	82.0	78.7	74.5	81.4
Weight of Evidence (alternative approaches-2002baseyear)									
Alt 1 - Base Year Des. Value (3-year period centered on 2002)	*96.0*	*92.0*	*93.0*	*95.0*	*91.0*	*92.0*	*96.0*	*94.0*	*97.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2002)	*96.0*	*92.0*	*93.0*	*96.0*	*91.0*	*92.0*	*96.0*	*94.0*	*97.0*
RRF (all days > 85 ppb, or at least 10 days)	0.885	0.908	0.938	0.888	0.947	0.914	0.894	0.918	0.924
Alt 1 - Future Year Projected Value	**85.0**	83.5	**87.2**	84.4	**86.2**	84.1	**85.8**	**86.3**	**89.6**
Alt 2 - Future Year Projected Value	**85.0**	83.5	**87.2**	**85.2**	**86.2**	84.1	**85.8**	**86.3**	**89.6**
Alt 1 - RRF (all days > 70 ppb)	0.885	0.914	0.940	0.901	0.945	0.911	0.912	0.907	0.918
Alt 1 - Future Year Projected Value	**85.0**	84.1	**87.4**	**85.6**	**86.0**	83.8	**87.6**	**85.3**	**89.0**
Alt 2 - Future Year Projected Value	**85.0**	84.1	**87.4**	**86.5**	**86.0**	83.8	**87.6**	**85.3**	**89.0**
Alt 2 - RRF (all days > 85 ppb, or at least 10 days; with acceptable model performance)	0.880	0.911	0.940	0.886	0.951	0.913	0.894	0.916	0.935
Alt 1 - Future Year Projected Value	84.5	83.8	**87.4**	84.2	**86.5**	84.0	**85.8**	**86.1**	**90.7**
Alt 2 - Future Year Projected Value	84.5	83.8	**87.4**	**85.1**	**86.5**	84.0	**85.8**	**86.1**	**90.7**
Weight of Evidence (alternative approaches-2005baseyear)									
Alt 1 - Base Year Des. Value (3-year period centered on 2005)	*80.0*	*86.0*	*81.0*	*84.0*	*85.0*	*86.0*	*80.0*	*76.0*	*82.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2005)	*85.0*	*89.0*	*86.0*	*88.0*	*89.0*	*89.0*	*87.0*	*81.0*	*90.0*
Alt 1 - Future Year Projected Value	75.3	81.4	78.3	79.5	79.7	81.0	75.6	72.0	77.7
Alt 2 - Future Year Projected Value	80.0	84.3	83.2	83.3	83.5	83.8	82.2	76.7	**85.2**

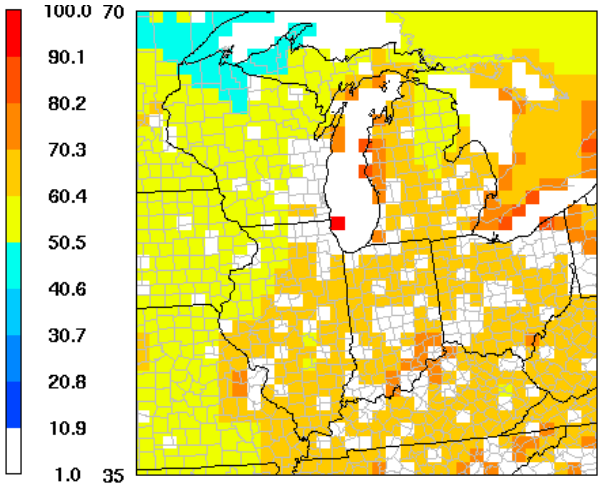


Figure 64. Estimated Future Year Values (unmonitored grid cells)

Finally, EPA's latest regional ozone modeling was considered as corroborative information. This modeling was performed as part of the June 2007 proposal to revise the ozone standard (EPA, 2007b). EPA applied the CMAQ model with 2001 meteorology to first estimate ozone levels in 2020 based on the current standard and national rules in effect or proposed (i.e., the baseline), and then to evaluate strategies for attaining a more stringent (70 ppb) primary standard. Baseline (2020) ozone levels were predicted to be below the current standard in 481 of the 491 counties with ozone monitors. Of the 10 counties predicted to be above the standard, there is one county in the LADCO region (i.e., Kenosha County, WI at 86 ppb). This result is consistent with LADCO's Base K modeling for 2018 (i.e., Kenosha County, WI at 86.7 ppb), which is not surprising given that EPA's modeling and LADCO's Base K modeling have a similar base year (2001 v. 2002).

Analysis of Trends: EPA's modeling guidelines note that while air quality models are generally the most appropriate tools for assessing the expected impacts of a change in emissions, it may also be possible to extrapolate future trends based on measured historical trends of air quality and emissions. To do so, USEPA's guidance suggests that ambient trends should first be normalized to account for year-to-year variations in meteorological conditions (EPA, 2002). Meterologically-adjusted 4th high 8-hour ozone concentrations were derived using the air quality – meteorological regression model developed by EPA (i.e., Cox method – see Section 2.1).

The historical trend in these met-adjusted ozone concentrations were extrapolated to estimate future year ozone concentrations based on historical and projected trends in precursor emissions. Both VOC and NOx emissions affect ozone concentrations. Given that observation-based methods show that urban areas in the region are generally VOC-limited and rural areas in the region are NOx-limited (see Section 2.1), urban VOC emissions and regional NOx emissions are considered important. The trends in urban VOC and regional NOx emissions were calculated to produce appropriate weighting factors.

The resulting 2009 and 2012 ozone values are provided in Figure 65, along with the primary and alternative modeling ozone values for key sites in the Lake Michigan, Cleveland, and Cincinnati areas. The results reflect a fairly wide scatter, but, on balance, the supplemental information is supportive of the primary modeling results (i.e., sites in the Lake Michigan area and Cleveland are expected to be close to the standard).

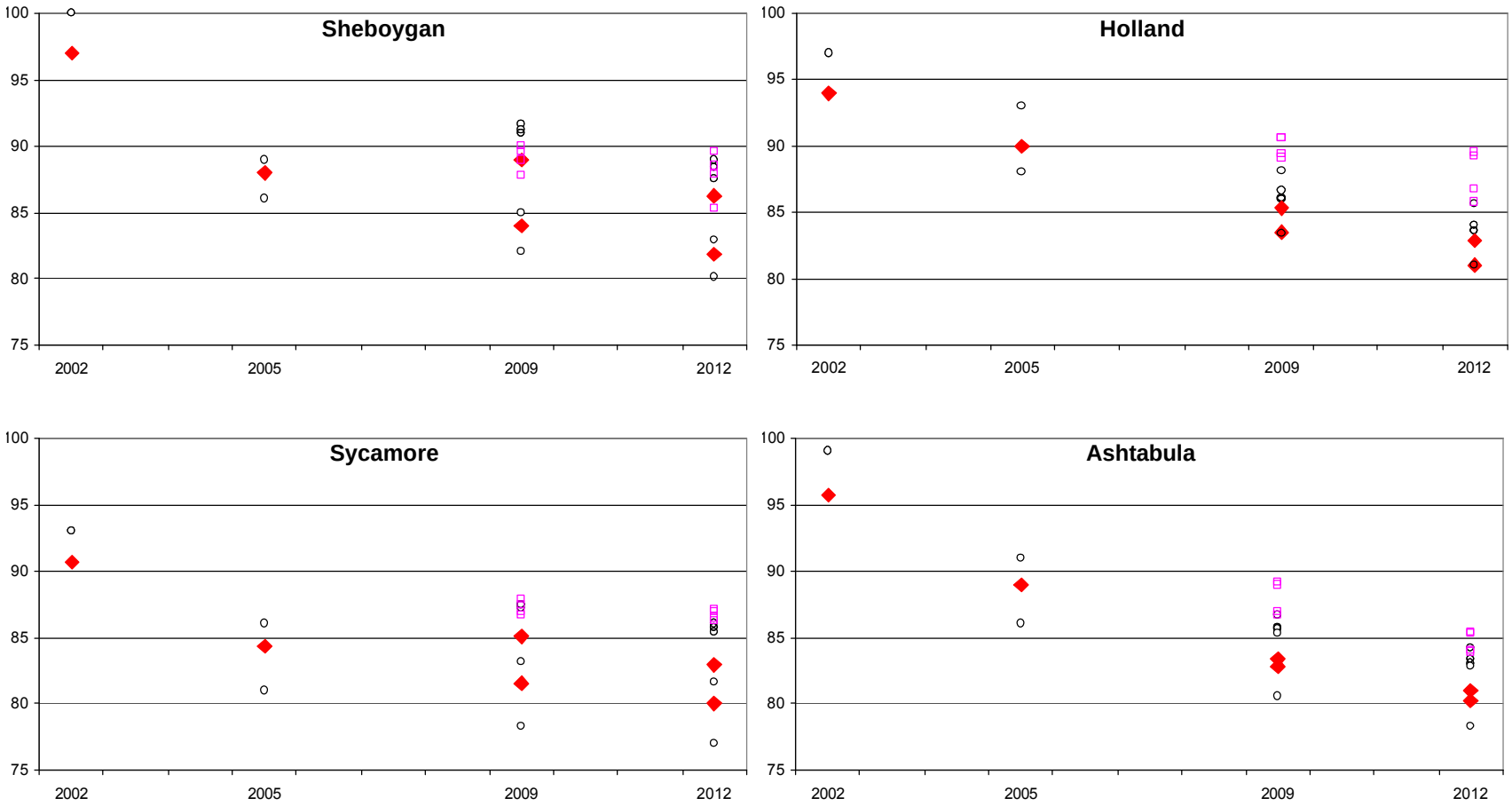


Figure 65. Estimates of Future Year Ozone Concentrations – Lake Michigan Area (Sheboygan and Holland), Cincinnati (Sycamore), and Cleveland (Ashtabula)

Note: Primary (guideline) modeling values (Base K and Base M results) are represented by large red diamonds, additional modeling values by small black circles, and trends-based values by small pink squares

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., MAPPER) is presented in Section 3. The key findings from this modeling are that most urban areas are VOC-limited and rural areas are NOx-limited.

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007a). Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 66) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and biogenic sources) at ozone monitoring sites in the region.

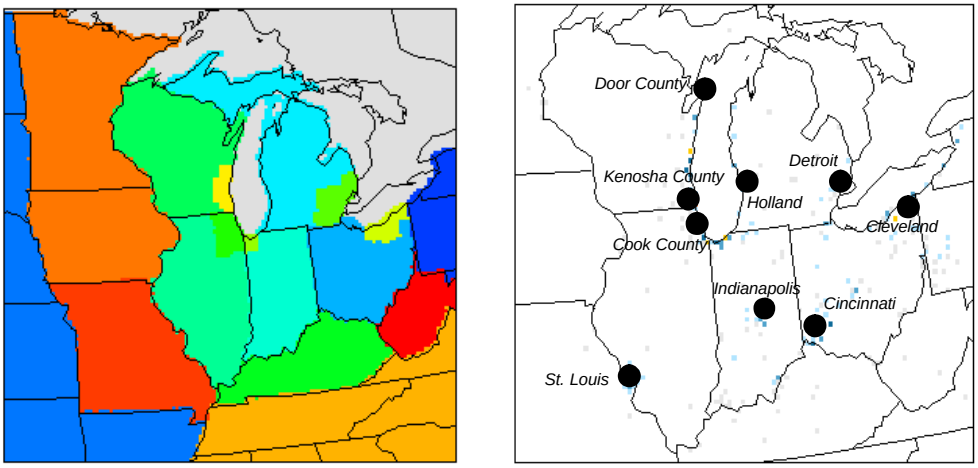


Figure 66. Source regions (left) and key monitoring sites (right) for ozone modeling analysis

Modeling results for 2009 (Base M) and 2012 (Base K) are provided in Appendix II for several key monitoring sites. For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of percentages. (Note, in the sector-level graph, the contributions from NOx emissions are shown in blue, and from VOC emissions in green.)

The sector-level results (see, for example, Figure 67) show that on-road and nonroad NOx emissions generally have the largest contributions at the key monitor locations (> 15% each). EGU and non-EGU NOx emissions are also important contributors (> 10% each). The source group contributions vary by receptor location due to emissions inventory differences.

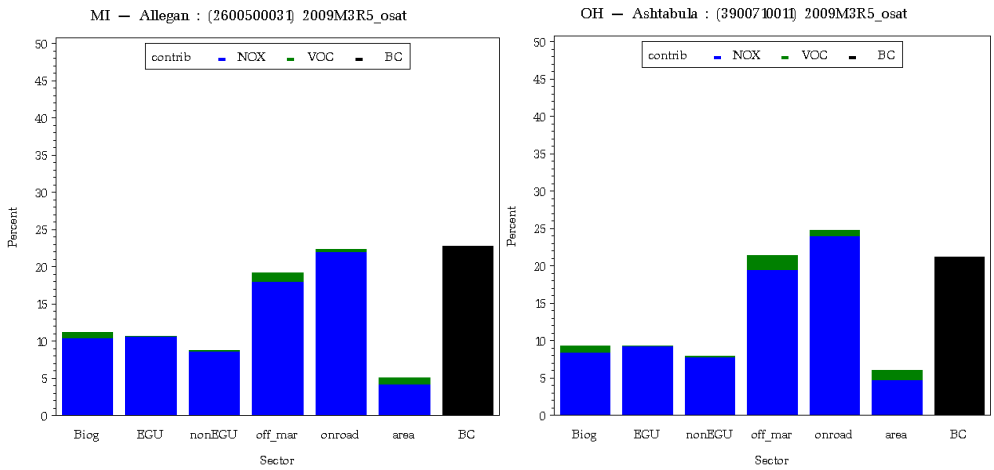


Figure 67. Source-sector results for Holland (left) and Ashtabula (right) monitors – 2009 (Base M)

The source region results (see, for example, Figure 68) show that while nearby areas generally have the highest impacts (e.g., the northeastern IL/northwestern IN/southeastern WI nonattainment area contributes 25-35% to high sites in the Lake Michigan area, and Cleveland nonattainment counties contribute 20-25% to high sites in northeastern Ohio), there is an even larger regional impact (i.e., contribution from other states).

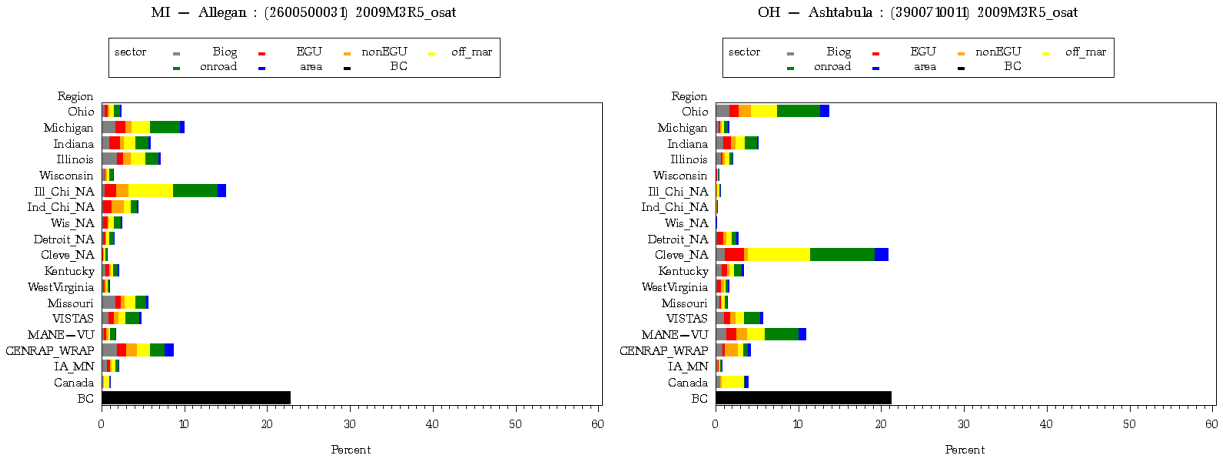


Figure 68. Source-region results for Holland (left) and Ashtabula (right) monitors – 2009 (Base M)

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year ozone concentrations. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to produce significant improvement in ozone air quality.
- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. As noted above, 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).
- Most sites are expected to meet the current 8-hour standard by the applicable attainment date, except, for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.
- Current monitoring data show significant nonattainment in these areas (e.g., peak design values on the order of 90 – 93 ppb). It is not clear whether sufficient emission reductions will occur in the next couple of years to provide for attainment.
- Attainment by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). On the other hand, if either of these conditions is not met, then attainment may be less likely.

4.3 Weight-of-Evidence Determination for $PM_{2.5}$

The WOE determination for $PM_{2.5}$ consists of the primary modeling and other supplemental analyses. A summary of this information is provided below.

Primary (Guideline) Modeling: The results of the guideline modeling are presented in Section 4.1. Key findings from this modeling include:

- Base M regional modeling shows attainment by 2009 at all sites, except Detroit, Cleveland, and Granite City, and attainment at all sites by 2012, except for Detroit and Granite City.

  The regional modeling for $PM_{2.5}$ does not reflect any air quality benefit expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$

- Base K modeling results reflect generally higher future year values, and show more sites in nonattainment in 2009 and 2012 compared to the Base M modeling. The difference in the two modeling analyses is due mostly to lower base year design values in Base M.

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for $PM_{2.5}$ should reflect a weight-of-evidence approach, with consideration of monitoring based information.

- Base M modeling also shows that the new $PM_{2.5}$ 24-hour standard will not be met at many sites, even by 2018, with existing controls.

Additional Modeling: EPA's latest regional $PM_{2.5}$ modeling was considered as corroborative information. This modeling was performed as part of the September 2006 revision to the $PM_{2.5}$ standard (USEPA, 2006). EPA applied the CMAQ model with 2001 meteorology to estimate $PM_{2.5}$ levels in 2015 and 2020 first with national rules in effect or proposed, and then with additional controls to attain the current standard (15 ug/m^3 annual/65 ug/m^3 daily). Additional analyses were performed to evaluate strategies for attaining more stringent standards in 2020 (15/35, and 14/35). Baseline (2015) $PM_{2.5}$ levels were predicted to be above the current standard in four counties in the LADCO region: Madison County, IL at 15.2 ug/m^3, Wayne County, MI at 17.4, Cuyahoga County, OH at 15.4, and Scioto County, OH at 15.6. These results are consistent with LADCO's Base K modeling for 2012/2018, which is not surprising given that EPA's modeling and LADCO's Base K modeling have a similar base year (2001 v. 2002).

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., application of thermodynamic equilibrium models) is presented in Section 3. The key findings from this modeling are that $PM_{2.5}$ mass is sensitive to reductions in sulfate, nitric acid, and ammonia concentrations. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases. Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007b). Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 69) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and biogenic sources) at $PM_{2.5}$ monitoring sites in the region.

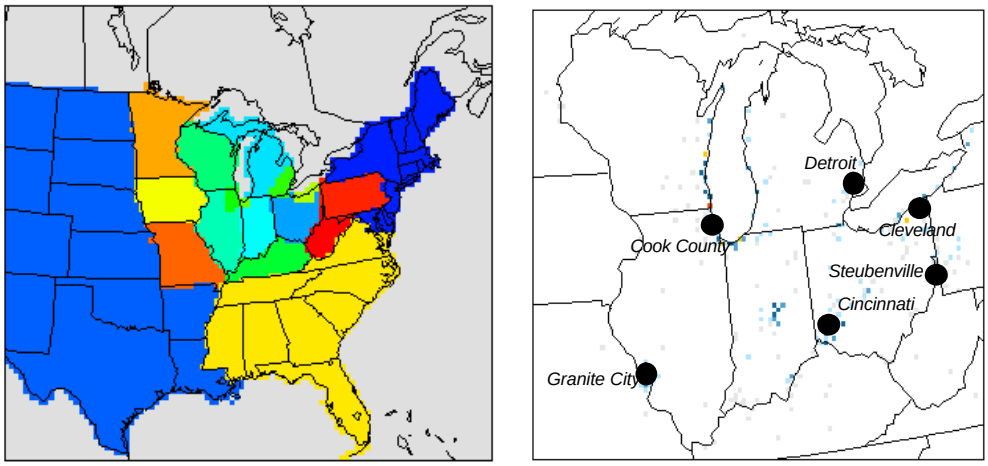


Figure 69. Source regions (left) and key monitoring sites (right) for $PM_{2.5}$ modeling analysis

Modeling results for 2012 (Base K) and 2018 (Base M) are provided in Appendix III for several key monitoring sites. For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of absolute modeled values.

The sector-level results (see, for example, Figure 70) show that EGU sulfate, non-EGU-sulfate, and area organic carbon emissions generally have the largest contributions at the key monitor locations (> 15% each). Ammonia emissions are also important contributors (> 10%). The source group contributions vary by receptor location due to emissions inventory differences.

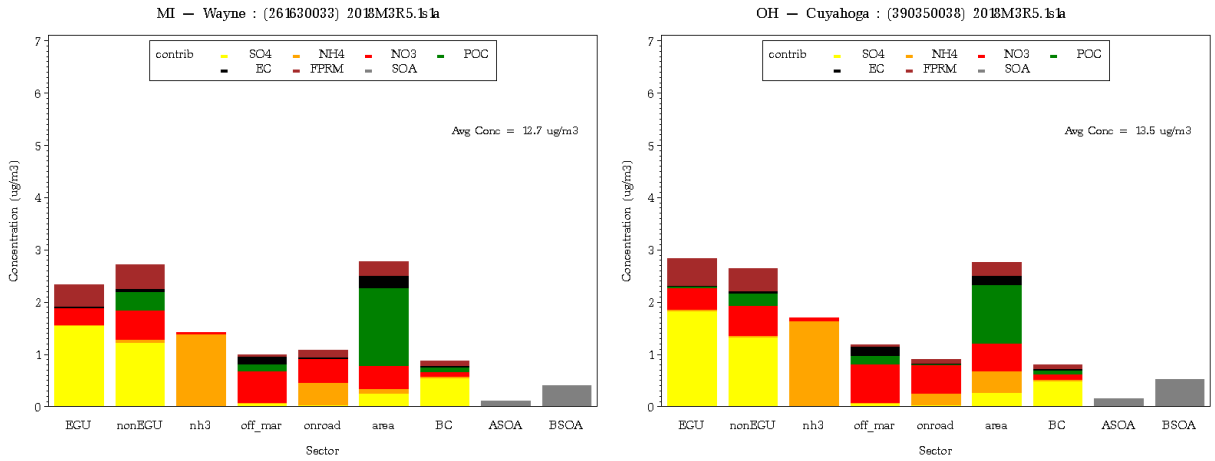


Figure 70. Source-sector results for Detroit (left) and Cleveland (right) monitors – 2018 (Base M)

The source region results (see, for example, Figure 71) show that while nearby areas generally have the highest impacts (e.g., Detroit nonattainment counties contribute 40% to high sites in southeastern Michigan, and Cleveland nonattainment counties contribute 35% to high sites in northeastern Ohio), there is an even larger regional impact (i.e., contribution from other states).

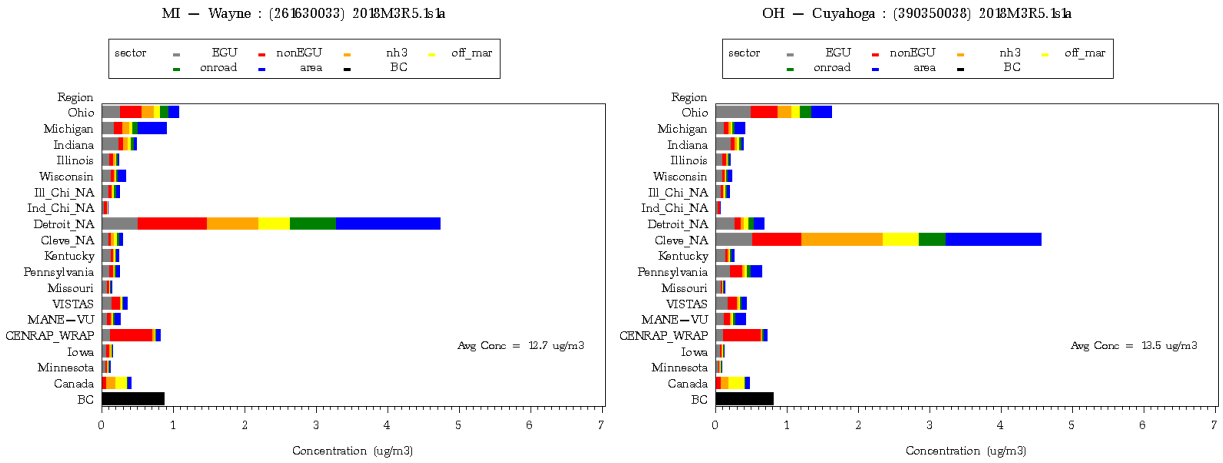


Figure 71. Source-region results for Detroit (left) and Cleveland (right) monitors – 2018 (Base M)

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year $PM_{2.5}$ concentrations. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to produce significant improvement in $PM_{2.5}$ air quality.
- The choice of the base year affects the future year model projections. It is not clear how much of this is attributable to differences in meteorology, because, as noted in Section 3, $PM_{2.5}$ concentrations are not as strongly influenced by meteorology as ozone.
- Most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.
- Current monitoring data show significant nonattainment in these areas (e.g., peak design values on the order of 16 – 17 ug/m^3). It is not clear whether sufficient emission reductions will occur in the next couple of years to provide for attainment. States are conducting local-scale analyses for Detroit, Cleveland, and Granite City, in particular, to identify appropriate additional local controls.
- Attainment by the applicable attainment date is dependent (possibly) on actual future year meteorology and (more likely) on actual future year emissions (e.g., if the emission reductions associated with the "on the books" controls are achieved, then attainment is likely). On the other hand, if either of these conditions is not met (especially, with respect to emissions), then attainment may be less likely.

Section 5. Reasonable Progress Assessment for Regional Haze

Air quality modeling and other information were used to assess the improvement in visibility that would be provided by existing ("on the books") controls and possible additional control programs. In determining reasonable progress for regional haze, Section 169A of the Clean Air Act and EPA's visibility rule requires states to consider five factors:

- costs of compliance
- time necessary for compliance
- energy and non-air quality environmental impacts of compliance
- remaining useful life of any existing source subject to such requirements
- uniform rate of visibility improvement needed to attain natural visibility conditions by 2064

The uniform rate of visibility improvement requirement can be depicted graphically in the form of a "glide path" (see Figure 72).

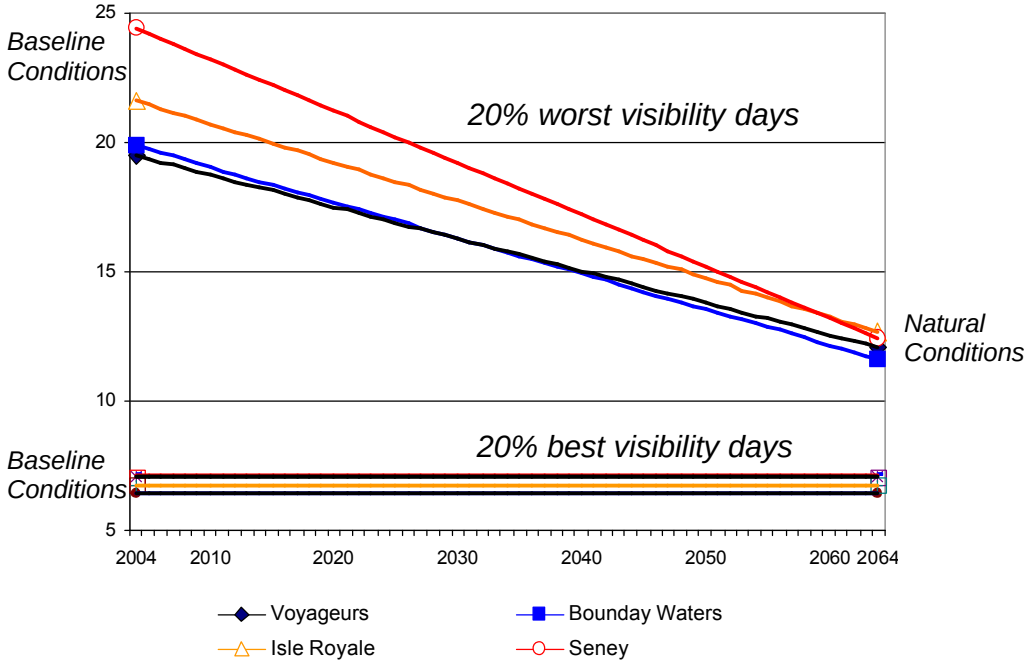


Figure 72. Visibility "glide paths" for northern Class I areas (units: deciviews)

5.1 Class I Areas Impacted

EPA's visibility rule requires a state to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." (40 CFR Part 51.308(d)) To meet this requirement, technical analyses conducted by the RPOs were consulted to obtain information on areas of influence and culpability for Class I areas in the eastern U.S. (MRPO, 2007). A summary of this information is provided in Table 1 (MRPO, 2007). The table shows that every LADCO State impacts multiple Class I areas in the eastern U.S.

Table 14. Draft List of Class I Areas Impacted by LADCO States

AREA NAME	IL	IN	MI	OH	WI
81.401 Alabama.					
Sipsey Wilderness Area	(1)	(1)			
81.404 Arkansas.					
Caney Creek Wilderness Area	(2), (4)	(2), (4)		(2), (4)	
Upper Buffalo Wilderness Area	(1),(2),(4),(5)	(2), (4)		(2), (4)	(2)
81.408 Georgia.					
Cohotta Wilderness Area					
Okefenokee Wilderness Area					
Wolf Island Wilderness Area					
81.411 Kentucky.					
Mammoth Cave NP	(1), (2), (5)	(1), (2), (5)	(1), (2)	(1), (2), (5)	
81.412 Louisiana.					
Breton Wilderness Area					
81.413 Maine.					
Acadia National Park	(3)	(3)	(3)	(3)	
Moosehorn Wilderness Area.	(3)	(3)	(3)	(3)	
81.414 Michigan.					
Isle Royale NP.	(1), (2)	(1), (2)	(1), (2)		(1), (2)
Seney Wilderness Area	(1), (2)	(1), (2)	(1), (2)	(1), (2)	(1), (2)
81.415 Minnesota.					
Boundary Waters Canoe Area Wilderness	(2)	(2)	(2)		(1), (2)
Voyageurs NP	(2)	(2)			(1), (2)
81.416 Missouri.					
Hercules-Glades Wilderness Area	(2), (4), (5)	(2), (4), (5)		(2), (4)	(2)
Mingo Wilderness Area	(2), (4), (5)	(2), (4), (5)	(2)	(2), (4)	(2)
81.419 New Hampshire.					
Great Gulf Wilderness Area	(3)	(3)	(3)	(1), (3)	
Pres. Range-Dry River Wilderness Area.					
81.42 New Jersey.					
Brigantine Wilderness Area	(3)	(3)	(1), (3)	(1), (3)	

81.422 North Carolina.					
Great Smoky Mountains NP{1}	(1)	(1)		(1)	
Joyce Kilmer-Slickrock Wilderness Area{2}					
Linville Gorge Wilderness Area.					
Shining Rock Wilderness Area.					
Swanquarter Wilderness Area					
81.426 South Carolina.					
Cape Romain Wilderness					
81.428 Tennessee.					
Great Smoky Mountains NP{1}.	(1)	(1)		(1)	
Joyce Kilmer-Slickrock Wilderness{2}					
81.431 Vermont.					
Lye Brook Wilderness	(2), (3)	(2), (3)	(2), (3)	(1), (2), (3)	
81.433 Virginia.					
James River Face Wilderness.	(2)	(2)	(2)	(2), (5)	
Shenandoah NP	(2), (3)	(1), (2), (3)	(2), (3)	(1),(2),(3),(5)	
81.435 West Virginia.					
Dolly Sods/Otter Creek Wilderness.	(2), (3)	(1), (2), (3)	(1), (2), (3)	(1),(2),(3),(5)	

Key
(1) MRPO Back Trajectory Analyses
(2) MRPO PSAT Modeling
(3) MANE-VU Contribution Assessment
(4) Missouri-Arkansas Contribution Assessment
(5) VISTAS Areas of Influence

5.2 Future Year Modeling Results

For regional haze, the calculation of future year conditions assumed:

- baseline concentrations based on 2000-2004 IMPROVE data, with updated (subsitituted) data for Mingo, Boundary Waters, Voyageurs, Isle Royale, and Seney (see Section 2.3);
- use of the new IMPROVE light extinction equation; and
- use of EPA default values for natural conditions, based on the new IMPROVE light extinction equation.

The uniform rate of visibility improvement values for the 2018 planning year were derived (for the 20% worst visibility days) based on a straight line between baseline concentration value (plotted in the year 2004 -- end year of the 5-year baseline period) and natural condition value (plotted in the year 2064 -- date for achieving natural conditions). Plots of these "glide paths" with the Base M modeling results are presented in Figure 73 for Class I areas in the eastern U.S. A tabular summary of measured baseline and modeled future year deciview values for these Class I areas are provided in Table 15 (2002 base year) and Table 16 (2005 base year)[13].

The haze results show that several Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values (in 2018), including those in northern Michigan and several in the northeastern U.S. Many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values (in 2018). As noted above, states should consider these results, along with information on the other four factors, in setting reasonable progress goals.

An assessment of the five factors was performed for LADCO and the State of Minnesota by a contractor (EC/R, 2007). Specifically, ECR examined reductions in SO2 and NOx emissions from EGUs and industrial, commercial and institutional (ICI) boilers; NOx emissions from mobile sources and reciprocating engines and turbines; and ammonia emissions from agricultural operations. The impacts of "on the books" controls were also examined to provide a frame of reference for assessing the impacts of the additional control measures.

The results of ECR's analysis of the five factors are summarized below:

> Factor 1 (Cost of Compliance): The average cost effectiveness values (in terms of $M per ton) are provided in Table 16. For comparison, cost-effectiveness estimates previously provided for "on the books" controls include:
>
> CAIR SO2: $700 - $1,200, NOx: $1,400 – $2.600 ($/T)
>
> BART SO2: $300 - $963, NOx: $248 - $1,770
>
> MACT SO2: $1,500, NOx: $7,600
>
> Most of the cost-effectiveness values for the additional controls are within the range of cost-effectiveness values for "on the books" controls.

[13] Model results reflect the grid cell where the IMPROVE monitor is located.

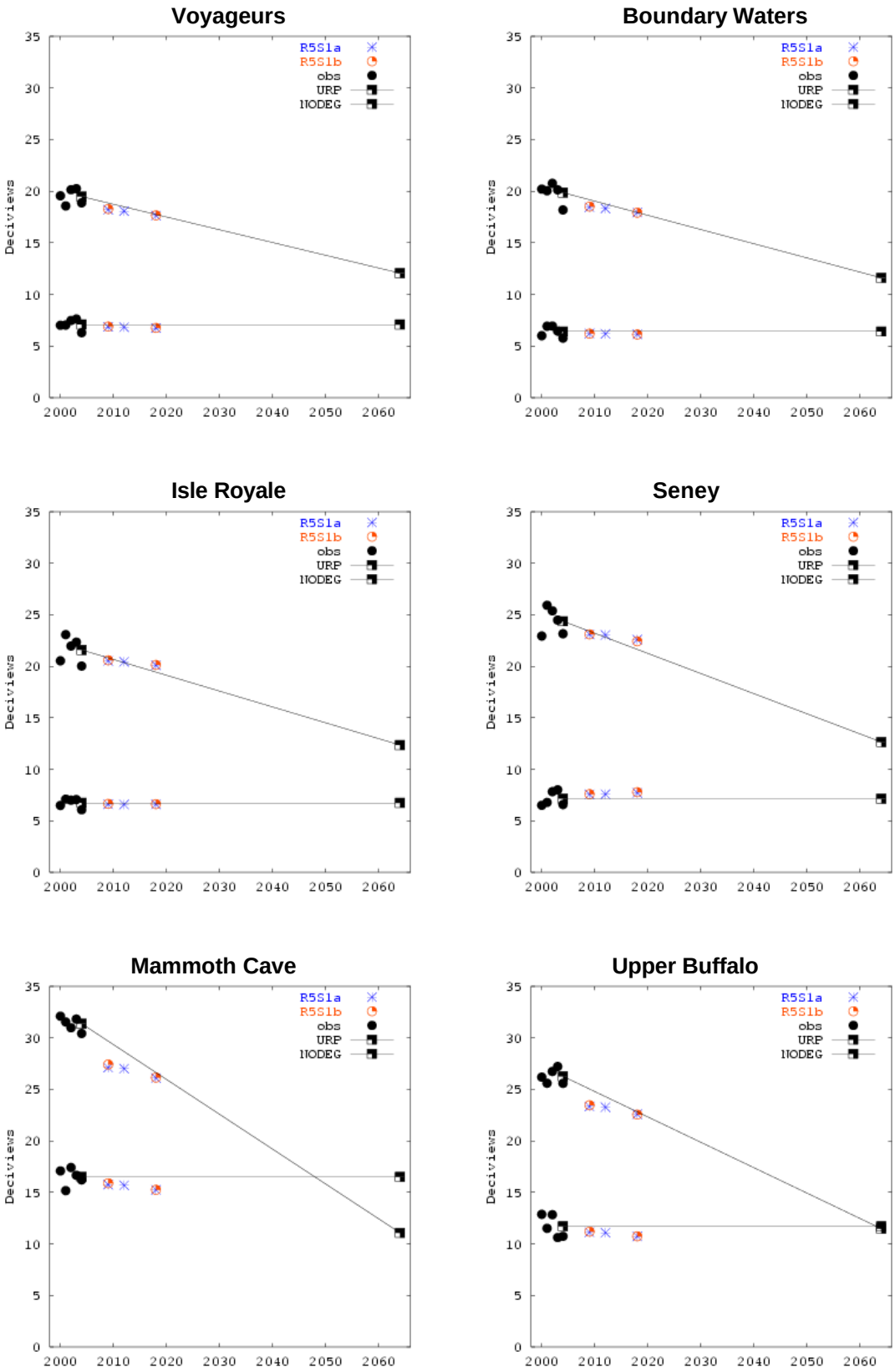


Figure 73. Visibility modeling results for Class I areas in eastern U.S.

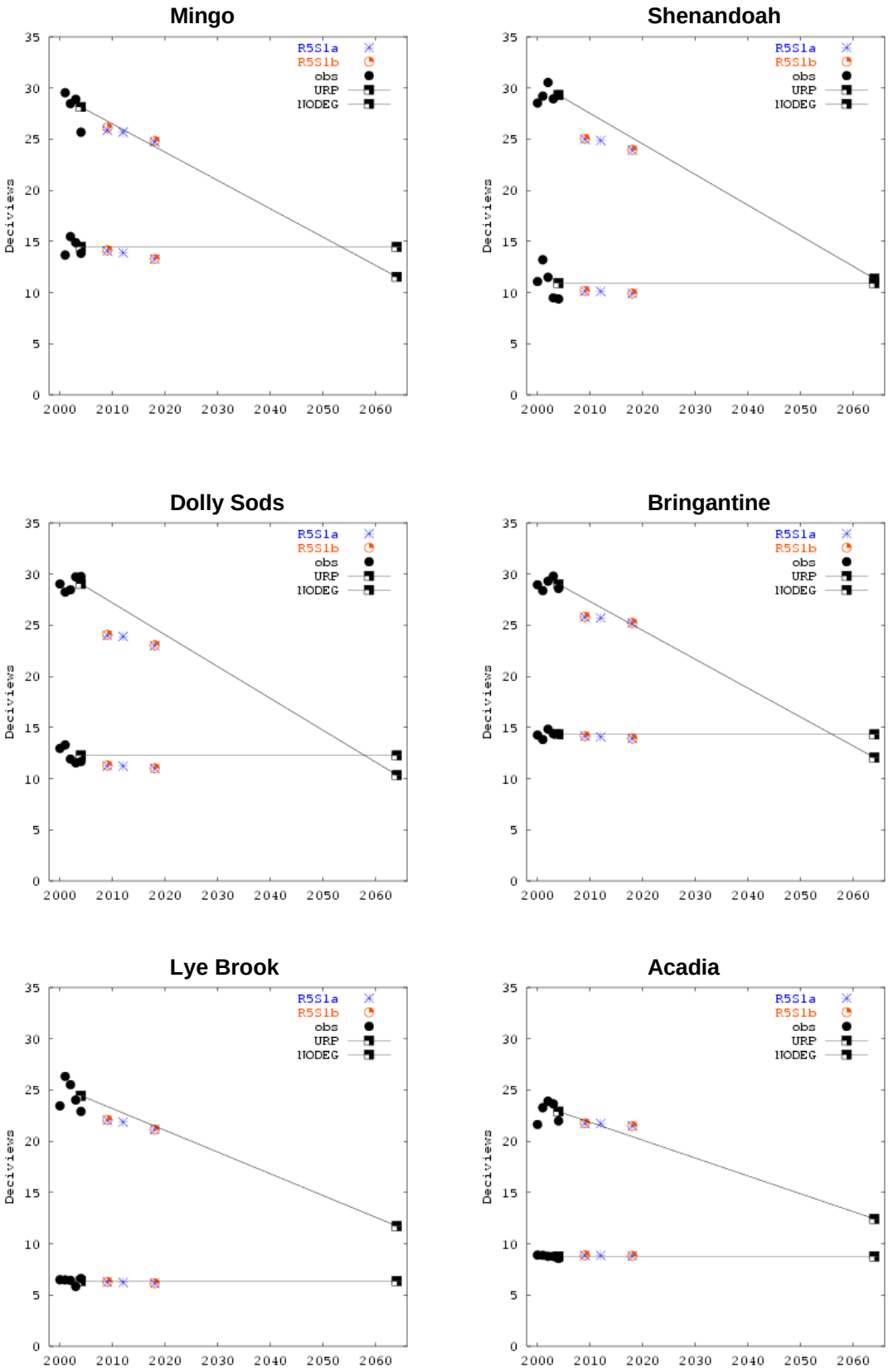


Figure 73 (cont.) Visibility modeling results for Class I areas in eastern U.S.

Table 15. Haze Results - Round 4 (Based on 2000-2004)							
Worst 20%		**2018**	**2009**	**2012**	**2018**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**EGU2 (5-state region)**	**EGU2 (12-state region)**
BOWA1	19.86	17.70	19.05	19.01	**18.94**	**18.40**	17.72
VOYA2	19.48	17.56	19.14	19.19	**19.18**	**18.94**	**18.38**
SENE1	24.38	21.35	22.98	22.71	**22.38**	21.26	20.63
ISLE1	21.59	19.21	20.46	20.28	**20.04**	19.09	18.64
HEGL1	26.75	22.76	24.73	24.34	**23.85**	**23.01**	22.04
MING1	28.15	24.08	25.18	24.67	24.01	22.53	21.45
CACR1	26.36	22.55	24.01	23.55	**22.99**	22.43	21.57
UPBU1	26.27	22.47	24.02	23.58	**23.06**	22.31	21.38
MACA1	31.37	26.14	28.06	27.03	25.52	24.27	22.57
DOSO1	29.04	24.23	24.86	23.59	22.42	21.60	20.15
SHEN1	29.31	24.67	24.06	22.79	21.57	20.43	19.42
JARI1	29.12	24.48	24.81	23.79	22.42	21.59	20.88
BRIG1	29.01	24.68	25.87	25.25	24.39	23.91	23.45
LYBR1	24.45	21.16	21.80	21.32	20.69	20.18	19.79
Best 20%		**2018**	**2009**	**2012**	**2018**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**EGU2 (5-state region)**	**EGU2 (12-state region)**
BOWA1	6.42	6.42	6.71	6.73	6.87	6.83	6.81
VOYA2	7.09	7.09	7.21	7.25	7.34	7.31	7.26
SENE1	7.14	7.14	7.19	7.19	7.23	7.06	6.91
ISLE1	6.75	6.75	6.57	6.51	6.47	6.20	6.06
HEGL1	12.84	12.84	12.61	12.62	12.61	12.43	12.02
MING1	14.46	14.46	13.96	13.93	13.94	13.74	13.33
CACR1	11.24	11.24	10.91	10.92	10.90	10.75	10.42
UPBU1	11.71	11.71	11.47	11.46	11.42	11.28	11.01
MACA1	16.51	16.51	16.06	15.91	15.54	15.18	14.75
DOSO1	12.28	12.28	11.72	11.45	11.19	10.93	10.67
SHEN1	10.93	10.93	9.73	9.53	9.17	9.05	8.90
JARI1	14.21	14.21	13.56	13.33	12.97	12.65	12.46
BRIG1	14.33	14.33	13.74	13.69	13.47	13.32	13.21
LYBR1	6.36	6.36	6.12	6.05	5.96	5.88	5.82

Table 16. Haze Results - Round 5.1 (Based on 2000-2004)						
Worst 20%		**2018**	**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	19.86	17.94	18.45	18.33	17.94	17.92
VOYA2	19.48	17.75	18.20	18.07	17.63	17.66
SENE1	24.38	21.64	23.10	23.04	**22.59**	**22.42**
ISLE1	21.59	19.43	20.52	20.43	**20.09**	**20.13**
ISLE9	21.59	19.43	20.33	20.22	**19.84**	**19.82**
HEGL1	26.75	23.13	24.72	24.69	**24.22**	**24.17**
MING1	28.15	24.27	25.88	25.68	**24.74**	**24.83**
CACR1	26.36	22.91	23.39	23.29	22.44	22.40
UPBU1	26.27	22.82	23.34	23.27	22.59	22.55
MACA1	31.37	26.64	27.11	27.01	26.10	26.15
DOSO1	29.05	24.69	24.00	23.90	23.00	23.04
SHEN1	29.31	25.12	24.99	24.87	23.92	23.95
JARI1	29.12	24.91	25.17	25.01	24.06	24.12
BRIG1	29.01	25.05	25.79	25.72	**25.21**	**25.22**
LYBR1	24.45	21.48	22.04	21.86	21.14	21.14
ACAD1	22.89	20.45	21.72	21.72	**21.49**	**21.49**
Best 20%		**2018**	**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**Max**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	6.42	6.42	6.21	6.19	6.14	6.12
VOYA2	7.09	7.09	6.86	6.83	6.75	6.76
SENE1	7.14	7.14	7.57	7.58	7.71	7.78
ISLE1	6.75	6.75	6.62	6.59	6.60	6.62
ISLE9	6.75	6.75	6.56	6.55	6.52	6.50
HEGL1	12.84	12.84	12.51	12.32	11.66	11.64
MING1	14.46	14.46	14.07	13.89	13.28	13.29
CACR1	11.24	11.24	10.88	10.85	10.52	10.52
UPBU1	11.71	11.71	11.13	11.08	10.73	10.74
MACA1	16.51	16.51	15.76	15.69	15.25	15.25
DOSO1	12.28	12.28	11.25	11.23	11.00	11.01
SHEN1	10.93	10.93	10.13	10.11	9.91	9.91
JARI1	14.21	14.21	13.38	13.38	13.14	13.14
BRIG1	14.33	14.33	14.15	14.08	13.92	13.92
LYBR1	6.37	6.37	6.25	6.23	6.14	6.15
ACAD1	8.78	8.78	8.86	8.86	8.82	8.82

Table 17. Estimated Cost Effectiveness for Potential Control Measures

			Average Cost effectiveness ($/ton)		
Emission category	Control strategy	Region	SO2	NOX	NH3
EGU	EGU1	3-State	1,540	2,037	
		9-State	1,743	1,782	
	EGU2	3-State	1,775	3,016	
		9-State	1,952	2,984	
ICI boilers	ICI1	3-State	2,992	2,537	
		9-State	2,275	1,899	
	ICI Workgroup	3-State	2,731	3,814	
		9-State	2,743	2,311	
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	3-State		538	
		9-State		506	
	Turbines emitting 100 tons/year or more	3-State		754	
		9-State		754	
	Reciprocating engines emitting 10 tons/year or more	3-State		1,286	
		9-State		1,023	
	Turbines emitting 10 tons/year or more	3-State		800	
		9-State		819	
Agricultural sources	10% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
	15% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
Mobile sources	Low-NOX Reflash	3-State		241	
		9-State		241	
	MCDI	3-State		10,697	
		9-State		2,408	
	Anti-Idling	3-State		(430) - 1,700	
		9-State		(430) - 1,700	
	Cetane Additive Program	3-State		4,119	
		9-State		4,119	
Cement Plants	Process Modification	Michigan		-	
	Conversion to dry kiln	Michigan		9,848	
	LoTox™	Michigan		1,399	
Glass Manufacturing	LNB	Wisconsin		1,041	
	Oxy-firing	Wisconsin		2,833	
	Electric boost	Wisconsin		3,426	
	SCR	Wisconsin		1,054	
	SNCR	Wisconsin		1,094	
Lime Manufacturing	Mid-kiln firing	Wisconsin		688	
	LNB	Wisconsin		837	
	SNCR	Wisconsin		1,210	
	SCR	Wisconsin		5,037	
	FGD	Wisconsin		128 - 4,828	
Oil Refinery	LNB	Wisconsin		3,288	
	SNCR	Wisconsin		4,260	
	SCR	Wisconsin		17,997	
	LNB+FGR	Wisconsin		4,768	
	ULNB	Wisconsin		2,242	
	FGD	Wisconsin		1,078	

Factor 2 (Time Necessary for Compliance): All of the control measures can be implemented by 2018. Thus, this factor can be easily addressed.

Factor 3 (Energy and Non-Air Quality Environmental Impacts): The energy and other environmental impacts are believed to be manageable. For example, the increased energy demand from add-on control equipment is less than 1% of the total electricity and steam production in the region, and solid waste disposal and wastewater treatment costs are less than 5% of the total operating costs of the pollution control equipment. It should also be noted that the SO2 and NOx controls would have beneficial environmental impacts (e.g., reduced acid deposition and nitrogen deposition).

Factor 4 (Remaining Useful Life): The additional control measures are intended to be market-based strategies applied over a broad geographic region. It is not expected that the control requirements will be applied to units that will be retired prior to the amortization period for the control equipment. Thus, this factor can be easily addressed.

Factor 5 (Visibility Impacts): The estimated incremental improvement in 2018 visibility levels for the additional measures is shown in Figure 74, along with the cost-effectiveness expressed in $M per deciview improvement). These results show that although EGU and ICI boiler controls have higher cost-per-deciview values (compared to some of the other measures), their visibility impacts are larger.

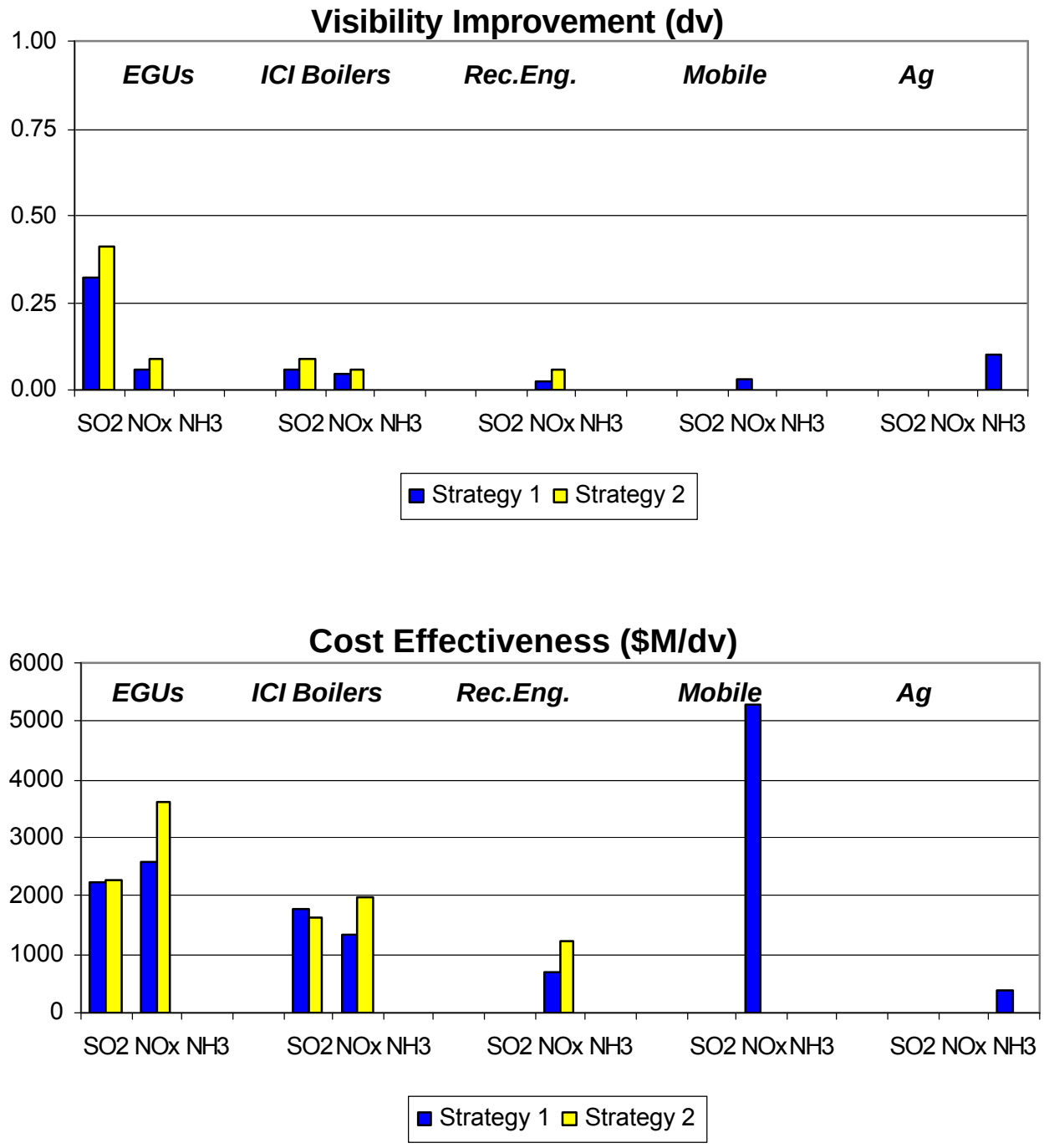


Figure 74. Results of ECR analysis of reasonable progress factors – visibility improvement (Factor 5) is on top, and cost effectiveness (Factor 1) is on bottom

5.3 Weight-of-Evidence Determination for Haze

The WOE determination for haze consists of the primary modeling and other supplemental analyses. A summary of this information is provided below.

Primary (Guideline) Modeling: The results of the guideline modeling are presented in Section 4.1. Key findings from this modeling include:

- Base M modeling results show that the northern Minnesota Class I areas are close to the glide path, whereas the northern Michigan Class I areas are above the glide path in 2018. Other sites in the eastern U.S. are close to (or below) the glide path, except for Mingo (MO), Brigantine (NJ), and Acadia (ME).

- Base K modeling results show that the northern Minnesota and northern Michigan Class I areas are above the glide path in 2018. Other sites in the eastern U.S. are close to (or below) the glide path.

- The difference in the two modeling analyses is due mostly to differences in future year emission projections, especially for EGUs (e.g., use of IPM2.1.9 v. IPM3.0).

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for haze should reflect a weight-of-evidence approach, with consideration of monitoring based information.

Additional Modeling: Two additional modeling analyses were considered: (1) the primary modeling redone with different baseline values, and (2) modeling by the State of Minnesota which looked at different receptor locations in the northern Class I areas (MPCA, 2008). Each of these analyses is described below.

First, the primary modeling analysis (Base M) was revised using an alternative baseline value. Specifically, the data for the period 2000-2005 were used to calculate the baseline, given that the Base M modeling reflects a 2005 base year. The results of this alternative analysis (see Table 18) are generally consistent with the primary modeling (see Table 16).

Second, Minnesota's modeling reflects a 2002 base year and much of the data developed by LADCO for its modeling. (Note, Minnesota conducted modeling for LADCO's domain at 36 km, and for a statewide domain at 12 km.) The purpose of the 12 km modeling was to address local scale impacts on the northern Class I areas at several locations, not just the location of the IMPROVE monitor. Results for the Boundary Waters on the 20% worst days range from 18.3 – 19.0 dv, with an average value of 18.7 dv, which is consistent with Minnesota's 36 km modeling results at the IMPROVE monitor. This variability in visibility levels should be kept in mind when reviewing the values presented in Tables 15, 16, and 18, which reflect results at the IMPROVE monitor locations.

Table 18. Haze Results - Round 5.1 (Based on 2000-2005)						
Worst 20%			**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	20.10	18.12	18.63	18.51	18.12	18.09
VOYA2	19.62	17.86	18.27	18.15	17.70	17.72
SENE1	24.77	21.94	23.44	23.39	**22.94**	**22.77**
ISLE1	21.95	19.71	20.84	20.76	**20.41**	**20.44**
ISLE9	21.95	19.71	20.65	20.55	**20.15**	**20.13**
HEGL1	27.45	23.67	25.30	25.27	**24.79**	**24.73**
MING1	28.92	24.86	25.88	25.68	24.74	24.83
CACR1	27.05	23.44	23.88	23.78	22.92	22.86
UPBU1	26.97	23.36	23.92	23.85	23.14	23.09
MACA1	31.76	26.93	27.42	27.32	26.39	26.44
DOSO1	29.36	24.92	24.20	24.11	23.19	23.23
SHEN1	29.45	25.23	25.06	24.94	23.98	24.01
JARI1	29.40	25.13	25.32	25.17	24.22	24.28
BRIG1	29.12	25.14	25.84	25.77	**25.26**	**25.26**
LYBR1	24.71	21.69	22.22	22.06	21.36	21.36
ACAD1	22.91	20.47	21.72	21.72	**21.49**	**21.49**
Best 20%			**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	6.40	6.40	6.20	6.17	6.13	6.10
VOYA2	7.05	7.05	6.82	6.78	6.71	6.71
SENE1	7.20	7.20	7.60	7.61	7.73	7.80
ISLE1	6.80	6.80	6.67	6.64	6.65	6.66
ISLE9	6.80	6.80	6.62	6.61	6.57	6.55
HEGL1	13.04	13.04	12.71	12.51	11.85	11.82
MING1	14.68	14.68	14.07	13.89	13.28	13.29
CACR1	11.62	11.62	11.24	11.20	10.86	10.86
UPBU1	11.99	11.99	11.41	11.36	11.01	11.02
MACA1	16.64	16.64	15.88	15.82	15.37	15.38
DOSO1	12.24	12.24	11.21	11.19	10.96	10.97
SHEN1	10.85	10.85	10.04	10.02	9.82	9.83
JARI1	14.35	14.35	13.51	13.51	13.27	13.27
BRIG1	14.36	14.36	14.17	14.10	13.94	13.94
LYBR1	6.21	6.21	6.11	6.09	6.01	6.01
ACAD1	8.57	8.57	8.67	8.66	8.62	8.62

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., application of thermodynamic equilibrium models) is presented in Section 3. The key findings from this modeling are that $PM_{2.5}$ mass is sensitive to reductions in sulfate, nitric acid, and ammonia concentrations. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases and visibility improves. Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

As discussed in Section 2, thermodynamic equilibrium modeling based on data collected at Seney indicates that $PM_{2.5}$ there is most sensitive to reductions in sulfate, but also responsive to reductions in nitric acid (Blanchard, 2004). An analysis using data from the Midwest ammonia monitoring network for a site in Minnesota (i.e., Great River Bluffs, which is the closest ammonia monitoring site to the northern Class I areas) suggested that reductions in sulfate, nitric acid, and ammonia concentrations will lower $PM_{2.5}$ concentrations and improve visibility levels in the northern Class I areas.

Trajectory analyses for the 20% worst visibility days for the four northern Class I areas are provided in Figure 75. (Note, this figure is similar to Figure 34, but the trajectory results for each Class I area are displayed separately here.) The orange areas are where the air is most likely to come from, and the green areas are where the air is least likely to come from. Darker shading represents higher frequency. As can be seen, bad air days are generally associated with transport from regions located to the south, and good air days with transport from Canada.

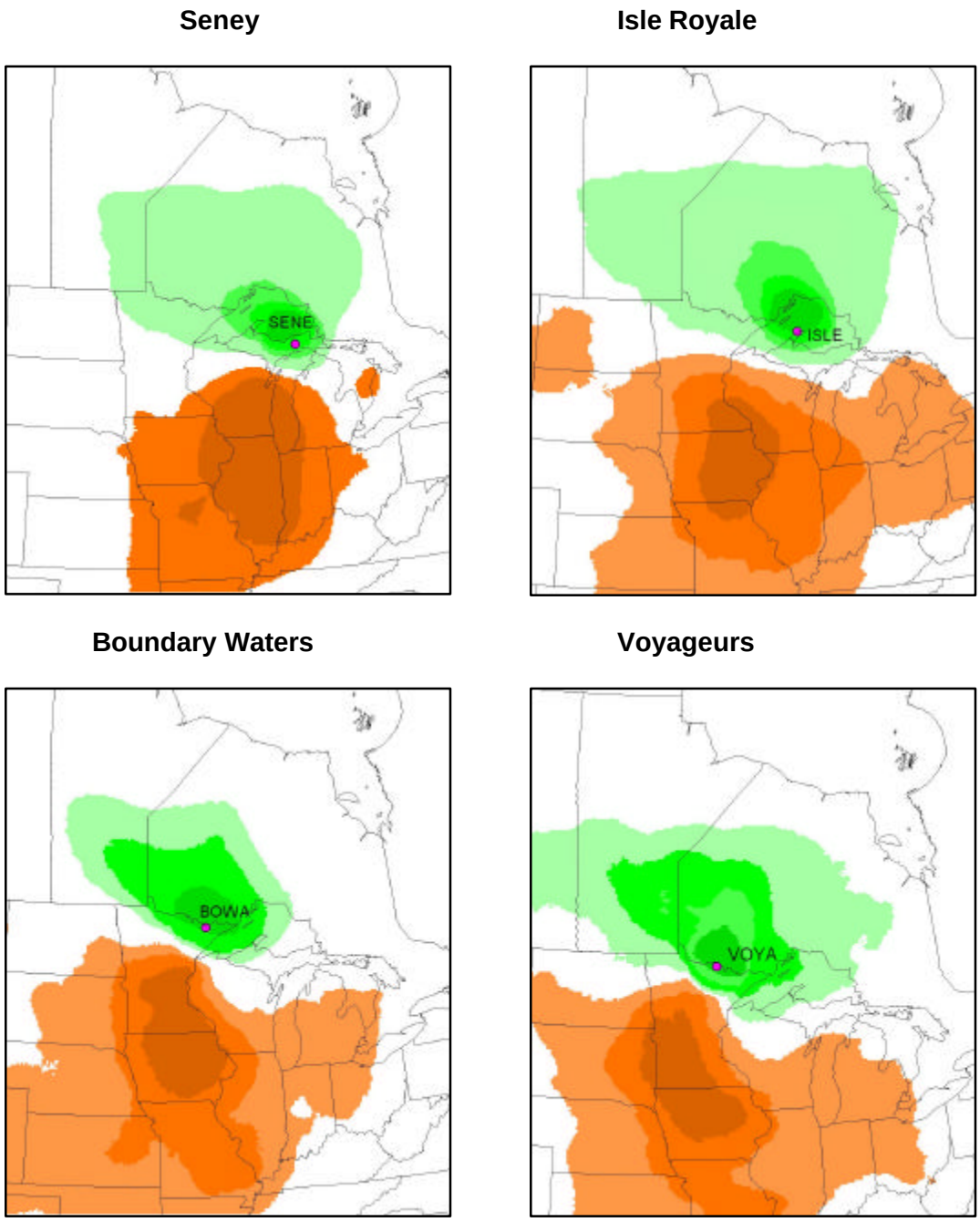


Figure 75. Trajectory analysis results for northern Class I areas on 20% worst visibility days

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007b). Specifically, the CAMx model was applied to provide source contribution information. Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 76) and 6 source se ctors (EGU point, non-EGU point, on-road, off-road, area, and ammonia sources) at visibility/haze monitoring sites in the eastern U.S.

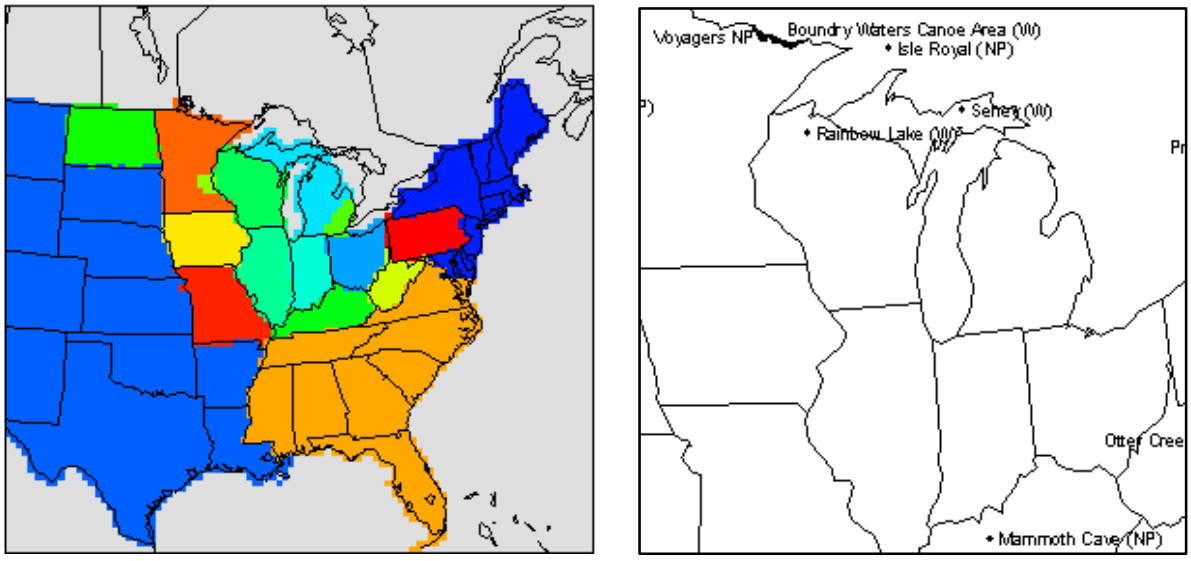


Figure 76. Source regions (left) and key monitoring sites (right) for haze modeling analysis

Modeling results for 2018 (Base K and Base M) are provided in Appendix IV for several key monitoring sites (Class I areas). For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of absolute modeled values.

The sector-level results (see, for example, Figure 77) show that EGU sulfate, non-EGU-sulfate, and ammonia emissions generally have the largest contributions at the key monitor locations. The source group contributions vary by receptor location due to emissions inventory differences.

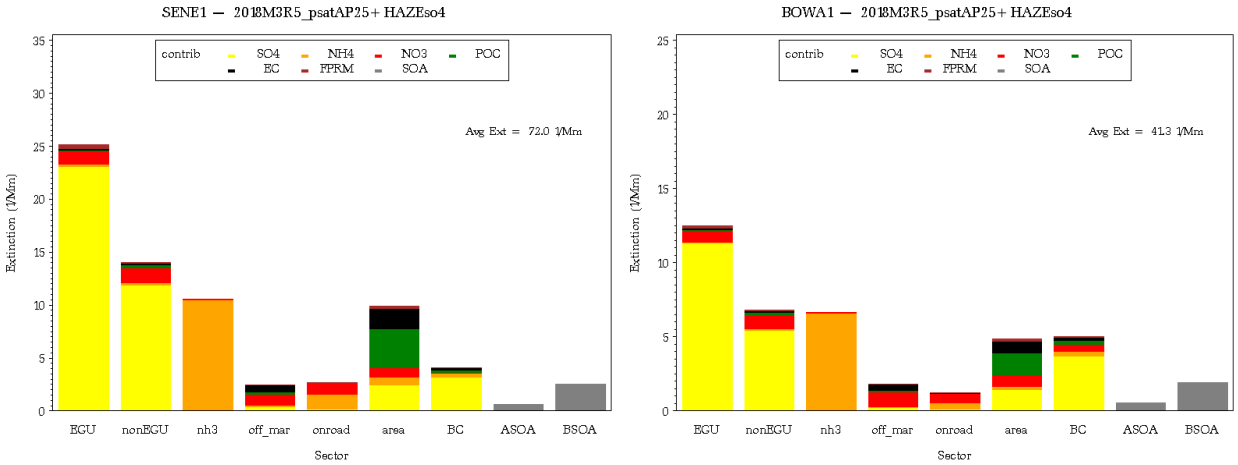


Figure 77. Source-sector results for Seney (left) and Boundary Waters (right) – 2018 (Base M)

The source region results (see, for example, Figure 78) show that emissions from a number of nearby states contribute to regional haze levels.

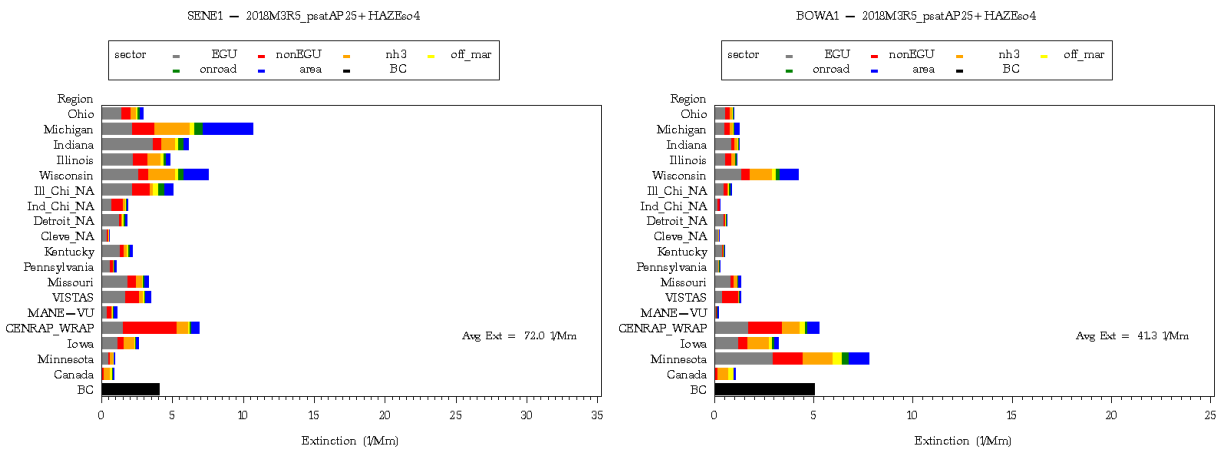


Figure 78. Source-region results for Seney (left) and Boundary Waters (right) – 2018 (Base M)

Table 19 provides a summary of the estimated state-level culpabilities based on the LADCO back trajectory analyses and the PSAT analyses for 2018.

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year visibility levels. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to improve visibility levels in the northern Class I areas.
- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018, including those in northern Michigan and some in the northeastern U.S.
- Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018.

Table 19. State Culpabilities Based on PSAT Modeling and Trajectory Analyses

	Boundary Waters						Seney			
	LADCO - Round 4 PSAT	**LADCO - Round 5 PSAT**	**MPCA-PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**		**LADCO - Round 4 PSAT**	**LADCO - Round 5 PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**
Michigan	3.4%	4.8%	3.0%	1.9%	0.7%		13.8%	18.1%		14.7%
Minnesota	30.5%	23.5%	28.0%	30.6%	37.6%		4.8%	1.6%		3.8%
Wisconsin	10.4%	10.9%	10.0%	6.4%	10.6%		12.6%	10.9%		8.4%
Illinois	5.2%	5.1%	6.0%	3.5%	2.7%		13.0%	14.3%		7.4%
Indiana	2.9%	3.9%	3.0%	1.8%	1.2%		9.6%	11.6%		2.2%
Iowa	7.6%	8.3%	8.0%	2.5%	7.4%		6.2%	3.8%		5.7%
Missouri	5.2%	3.4%	6.0%	2.1%	3.3%		6.5%	4.8%		3.2%
N. Dakota	5.7%	1.1%	6.0%	4.6%	5.9%		1.5%	0.1%		0.6%
Canada	1.9%	2.7%	3.0%	12.5%	15.1%		2.1%	1.2%		11.1%
CENRAP-WRAP	10.9%	13.5%		4.2%	10.1%		13.1%	10.0%		7.0%
	83.6%	**77.2%**	**73.0%**	**70.2%**	**94.6%**		**83.3%**	**76.4%**		**64.1%**
	Voyageurs						**Isle Royale**			
	LADCO - Round 4 PSAT	**LADCO - Round 5 PSAT**	**MPCA-PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**		**LADCO - Round 4 PSAT**	**LADCO - Round 5 PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**
Michigan	2.0%	4.9%	2.0%	1.0%	1.6%		12.7%	13.4%		
Minnesota	35.0%	20.2%	31.0%	31.5%	36.9%		14.1%	9.5%		
Wisconsin	6.3%	7.9%	6.0%	3.7%	9.7%		16.3%	14.7%		
Illinois	3.0%	7.1%	3.0%	1.8%	1.2%		7.0%	8.7%		
Indiana	1.6%	4.6%	2.0%	0.8%			5.6%	5.2%		
Iowa	7.4%	7.1%	7.0%	2.4%	10.2%		6.9%	8.3%		
Missouri	4.3%	4.0%	4.0%	1.6%	0.3%		3.9%	4.6%		
N. Dakota	10.3%	1.7%	13.0%	6.1%	7.1%		3.6%	0.3%		
Canada	2.7%	3.3%	5.0%	17.2%	13.3%		2.2%	1.7%		
CENRAP-WRAP	10.2%	13.7%		6.1%	16.5%		12.5%	12.6%		
	82.7%	**74.5%**	**73.0%**	**72.2%**	**96.8%**		**84.9%**	**79.0%**		

Section 6. Summary

To support the development of SIPs for ozone, $PM_{2.5}$, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin, technical analyses were conducted by LADCO, its member states, and various contractors. The analyses include preparation of regional emissions inventories and meteorological modeling data for two base years, evaluation and application of regional chemical transport models, and review of ambient monitoring data.

Analyses of monitoring data were conducted to produce a conceptual model, which is a qualitative summary of the physical, chemical, and meteorological processes that control the formation and distribution of pollutants in a given region. Key findings of the analyses include:

Ozone

- Current monitoring data show about 20 sites in violation of the 8-hour ozone standard of 85 ppb. Historical ozone data show a steady downward trend over the past 15 years, especially since 2001-2003, due likely to federal and state emission control programs.

- Ozone concentrations are strongly influenced by meteorological conditions, with more high ozone days and higher ozone levels during summers with above normal temperatures.

- Inter- and intra-regional transport of ozone and ozone precursors affects many portions of the five states, and is the principal cause of nonattainment in some areas far from population or industrial centers

$PM_{2.5}$

- Current monitoring data show 30 sites in violation of the annual $PM_{2.5}$ standard of 15 ug/m^3. Nonattainment sites are characterized by an elevated regional background (about 12 – 14 ug/m^3) and a significant local (urban) increment (about 2 – 3 ug/m^3). Historical $PM_{2.5}$ data show a slight downward trend since deployment of the $PM_{2.5}$ monitoring network in 1999.

- $PM_{2.5}$ concentrations are also influenced by meteorology, but the relationship is more complex and less well understood compared to ozone.

- On an annual average basis, $PM_{2.5}$ chemical composition consists of mostly sulfate, nitrate, and organic carbon in similar proportions.

Haze

- Current monitoring data show visibility levels in the Class I areas in northern Michigan are on the order of 22 – 24 deciviews. The goal of EPA's visibility program is to achieve natural conditions, which is on the order of 12 deciviews for these Class I areas, by the year 2064.

- Visibility impairment is dominated by sulfate and nitrate.

Air quality models were applied to support the regional planning efforts. Two base years were used in the modeling analyses: 2002 and 2005. EPA's modeling guidance recommends using

2002 as the baseline inventory year, but also allows for use of an alternative baseline inventory year, especially a more recent year. Initially, LADCO conducted modeling with a 2002 base year (i.e., Base K modeling, which was completed in 2006). A decision was subsequently made to conduct modeling with a 2005 base year (i.e., Base M, which was completed in 2007). Statistical analyses showed that 2002 and 2005 both had above normal ozone-conducive conditions, although 2002 was more severe compared to 2005. Examination of multiple base years provides for a more complete technical assessment. Both sets of model runs are discussed in this document.

Basecase modeling was conducted to evaluate model performance (i.e., assess the model's ability to reproduce the observed concentrations). This exercise was intended to assess whether, and to degree, confidence in the model is warranted (and to assess whether model improvements are necessary). Model performance for ozone and $PM_{2.5}$ was generally acceptable and can be characterized as follows:

Ozone

- Good agreement between modeled and monitored concentration for higher concentration levels (> 60 ppb) – i.e., bias within 30%

- Regional modeled concentrations appear to be underestimated in the 2002 base year, but show better agreement (with monitored data) in the 2005 base year due to model and inventory improvements.

- Day-to-day and hour-to-hour variation in and spatial patterns of modeled concentrations are consistent with monitored data

- Model accurately simulates the change in monitored ozone concentrations due to reductions in precursor emissions.

$PM_{2.5}$

- Good agreement in the magnitude of fine particle mass, but some species are overestimated and some are underestimated
    - Sulfates: good agreement in the 2002 base year, but underestimated in the summer in the 2005 base year due probably to meteorological factors
    - Nitrates: slightly overestimated in the winter in the 2002 base year, but good agreement in the 2005 base year as a result of model and inventory improvements
    - Organic Carbon: grossly underestimated in the 2002 and 2005 base years due likely to missing primary organic carbon emissions

- Temporal variation and spatial patterns of modeled concentrations are consistent with monitored data

Future year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Traditionally, attainment demonstrations involved a "bright line" test in which a single modeled value (based on EPA guidance) was compared to the ambient standard. To provide a more robust assessment of expected future year air quality, other information was considered. Furthermore, according to EPA's modeling guidance, if the future year modeled values are "close" to the

standard (i.e., 82 – 87 ppb for ozone and 14.5 – 15.5 ug/m^3 for $PM_{2.5}$), then the results of the primary modeling should be reviewed along with the supplemental information in a "weight of evidence" (WOE) assessment of whether each area is likely to achieve timely attainment. Key findings of the WOE determination include:

- Existing controls are expected to produce significant improvement in ozone and $PM_{2.5}$ concentrations and visibility levels.

- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).

- Most sites are expected to meet the current 8-hour standard by the applicable attainment date, except for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.

- Most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.

  The regional modeling for $PM_{2.5}$ does not reflect air quality benefits expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$.

- These findings of residual nonattainment for ozone and $PM_{2.5}$ are supported by current (2005 – 2007) monitoring data which show significant nonattainment in the region (e.g., peak ozone design values on the order of 90 – 93 ppb, and peak $PM_{2.5}$ design values on the order of 16 - 17 ug/m^3). It is unlikely that sufficient emission reductions will occur in the next few of years to provide for attainment at all sites.

- Attainment at most sites by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). If either of these conditions is not met, then attainment may be less likely.

- The new $PM_{2.5}$ 24-hour standard and the new lower ozone standard will not be met at several sites, even by 2018, with existing controls.

- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018 based on existing controls, including those in northern Michigan and some in the northeastern U.S. Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018.

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APPENDIX I

Ozone and $PM_{2.5}$ Modeling Results

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2008 - OTB		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	
Lake Michigan Area														***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.968	**82.0**	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.966	77.6	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.963	79.6	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.960	80.0	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.957	81.3	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.959	**84.4**	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.954	78.9	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.956	**84.8**	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.971	75.4	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.971	77.0	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.964	74.2	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.967	75.7	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.951	**85.6**	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.950	77.9	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.951	80.8	Muskegon
Indianapolis Area														***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.944	78.0	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.948	73.9	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.951	74.8	Fort B. Harrison
Detroit Area														***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.962	**82.7**	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.982	**82.5**	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.956	79.0	Port Huron
Cleveland Area														***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.954	**84.9**	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.954	75.7	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.959	**82.8**	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.948	79.3	
Cincinnati Area														***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.945	77.8	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.965	81.7	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.954	**83.6**	Lebanon
Columbus Area														***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.946	75.4	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.954	**82.4**	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.958	77.0	Franklin
St. Louis Area														***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.954	**82.4**	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.958	**83.3**	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.966	79.5	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.956	78.7	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.962	79.8	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.967	**84.5**	Maryland Heights (MO)

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2009 - OTB			2009 - Will Do		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	Round 4	RRF	Round 5	
Lake Michigan Area																	***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.972	**82.3**	**92.0**	0.971	**82.2**	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.965	77.5	**84.9**	0.964	77.4	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.965	79.8	**84.9**	0.964	79.7	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.961	80.1	**85.4**	0.960	80.0	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.951	80.8	78.9	0.949	80.7	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.955	**84.0**	**88.9**	0.953	**83.9**	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.945	78.1	81.0	0.943	78.0	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.946	**83.9**	81.8	0.945	**83.8**	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.971	75.4	**86.6**	0.970	75.3	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.971	77.0		0.970	77.0	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.960	73.9	**86.5**	0.959	73.8	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.965	75.6	82.8	0.964	75.5	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.948	**85.3**	**83.4**	0.947	**85.2**	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.940	77.1	77.6	0.939	77.0	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.947	80.5	81.5	0.945	80.3	Muskegon
Indianapolis Area																	***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.945	78.1	**83.7**	0.946	78.2	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.947	73.9	**83.8**	0.948	73.9	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.955	75.1	**83.7**	0.956	75.2	Fort B. Harrison
Detroit Area																	***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.947	81.4	**85.3**	0.947	81.4	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.968	81.3	**83.3**	0.969	81.4	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.937	77.5	79.1	0.938	77.5	Port Huron
Cleveland Area																	***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.937	**83.4**	**82.7**	0.941	**83.7**	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.942	74.7	**88.8**	0.945	75.0	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.949	81.9	**82.8**	0.954	**82.4**	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.934	78.1	81.4	0.935	78.2	
Cincinnati Area																	***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.941	77.5	**83.5**	0.942	77.6	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.967	81.9	**84.7**	0.968	82.0	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.947	**83.0**	79.0	0.948	**83.1**	Lebanon
Columbus Area																	***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.941	75.0	78.4	0.942	75.0	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.947	81.8	**82.6**	0.948	81.8	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.945	75.9	76.5	0.948	76.2	Franklin
St. Louis Area																	***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.938	81.0	**85.2**	0.932	80.5	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.942	**82.0**	**82.2**	0.939	81.7	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.956	78.7	81.9	0.954	78.5	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.938	77.2	77.4	0.937	77.1	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.955	79.3	**83.4**	0.955	79.3	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.955	**83.4**		0.954	**83.3**	Maryland Heights (MO)

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2012 - OTB			2018 - OTB		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	Round 4	RRF	Round 5	
Lake Michigan Area																	***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.956	80.9	**90.3**	0.900	76.2	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.947	76.1	**82.9**	0.886	71.2	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.944	78.0	**82.3**	0.880	72.7	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.939	78.3	**82.9**	0.870	72.5	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.925	78.6	76.3	0.853	72.5	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.930	81.8	**86.4**	0.857	75.4	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.918	75.9	79.1	0.845	69.9	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.919	81.5	79.3	0.843	74.7	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.960	74.6	**86.3**	0.922	71.6	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.960	76.2		0.922	73.1	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.942	72.5	**85.4**	0.884	68.1	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.951	74.5	**82.0**	0.904	70.8	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.920	**82.8**	81.0	0.846	76.1	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.909	74.5	75.5	0.838	68.7	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.918	78.0	79.4	0.846	71.9	Muskegon
Indianapolis Area																	***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.914	75.6	**82.0**	0.831	68.7	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.916	71.4	**82.1**	0.835	65.1	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.931	73.2	**82.4**	0.879	69.1	Fort B. Harrison
Detroit Area																	***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.932	80.2	**83.5**	0.885	76.1	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.961	80.7	81.9	0.924	77.6	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.913	75.5	77.0	0.858	70.9	Port Huron
Cleveland Area																	***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.910	81.0	80.2	0.844	75.1	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.916	72.7	**86.2**	0.848	67.3	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.932	80.5	80.6	0.883	76.2	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.903	75.6	78.5	0.821	68.7	Akron
Cincinnati Area																	***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.910	74.9	81.1	0.830	68.3	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.948	80.3	**82.9**	0.881	74.6	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.921	80.7	77.0	0.846	74.2	Lebanon
Columbus Area																	***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.911	72.6	76.5	0.832	66.3	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.922	79.6	80.2	0.845	73.0	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.923	74.1	74.7	0.859	69.0	Franklin
St. Louis Area																	***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.911	78.6	**84.0**	0.868	74.9	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.919	80.0	80.4	0.876	76.2	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.937	77.1	80.6	0.897	73.9	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.918	75.6	75.8	0.874	72.0	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.939	77.9	**82.5**	0.896	74.4	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.936	81.7		0.894	78.1	Maryland Heights (MO)

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2009 Modeling Results		
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	**14.1**	**14.8**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	**14.4**	**15.8**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.9	**14.5**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.8	**14.5**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.7	**14.5**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	**14.2**	**14.8**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.4**	**15.3**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**15.1**	**16.0**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	**14.1**	**14.9**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.8	**15.5**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	12.4	13.8	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		13.0		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.8	**14.5**	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		13.4		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	13.4	**14.8**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	13.0	**14.5**	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	**14.2**	**15.8**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	13.1	**14.1**	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.8**	**17.7**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	13.1	**15.1**	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	13.5	**14.2**	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	13.1	13.5	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	13.5	**14.4**	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**15.2**	**16.1**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	**14.4**	**14.6**	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**15.0**	**15.3**	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	**14.0**	**14.1**	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.9	**14.6**	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	12.7	**14.1**	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	11.7	**14.0**	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	**14.5**	**15.5**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.8	13.6	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	**14.0**	**14.6**	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.9	13.6	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	13.4	**14.2**	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.7**	**15.2**	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.8	**16.3**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.5	**15.5**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.8	**14.2**	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	13.2	13.7	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	12.1	**15.4**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	**14.0**	**15.0**	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	12.6	13.6	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	13.0	**14.4**	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	12.3	13.6	Akron - W. Exchange

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2012 Modeling Results		
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	**14.0**	**14.6**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	**14.2**	**15.5**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.8	**14.3**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.7	**14.3**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.6	**14.3**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	**14.0**	**14.6**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.3**	**15.1**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**14.9**	**15.8**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	13.9	**14.7**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.7	**15.0**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	12.2	13.5	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		12.8		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.6	**14.2**	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		13.2		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	13.1	**14.9**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	12.8	**14.1**	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	13.9	**15.3**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	12.8	13.7	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.5**	**17.1**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	12.8	**14.7**	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	13.2	13.7	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	12.9	12.9	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	13.2	13.8	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**14.8**	**15.4**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	**14.0**	**14.0**	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**14.6**	**14.7**	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	13.6	13.5	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.6	**14.0**	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	12.4	13.5	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	11.4	13.4	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	**14.3**	**14.8**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.6	13.0	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	13.8	**14.0**	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.7	13.0	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	13.2	13.6	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.4**	**14.6**	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.5	**15.9**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.2	**15.0**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.5	13.7	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	12.9	13.2	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	11.9	**14.8**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	13.6	**14.3**	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	12.3	13.0	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	12.7	13.6	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	12.0	13.0	Akron - W. Exchange

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2018 Modeling Results			
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5 OTB	Round 5 Will Do	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	13.9	13.8	**14.4**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	13.9	13.8	**15.0**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.7	13.5	**14.1**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.6	13.4	**14.1**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.4	13.3	**14.1**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	13.9	13.8	**14.4**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.2**	**14.0**	**14.9**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**14.3**	**14.2**	**15.5**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	13.4	13.3	**14.5**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.4	13.4	**14.4**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	11.8	11.9	13.0	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		12.4	12.4		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.0	12.1	13.7	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		12.6	12.7		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	12.6	12.6	**14.0**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	12.4	12.4	13.3	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	13.5	13.5	**14.4**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	12.5	12.5	13.0	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.1**	**15.1**	**16.1**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	12.5	12.5	13.9	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	12.8	12.8	13.1	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	12.5	12.6	12.2	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	12.7	12.9	12.9	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**14.3**	**14.5**	**14.4**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	13.5	13.7	13.1	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**14.1**	**14.2**	13.7	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	13.1	13.3	12.6	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.0	12.1	13.0	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	11.9	11.9	12.5	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	10.9	11.0	12.5	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	13.8	13.9	**14.0**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.2	12.3	12.3	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	13.4	13.4	13.2	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.3	12.4	12.2	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	12.8	12.8	12.8	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.0**	**14.1**	13.8	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.7	12.7	**16.2**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.4	13.4	**15.3**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.3	12.3	13.2	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	12.4	12.5	12.3	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	11.6	11.6	**14.2**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	13.3	13.3	13.6	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	11.9	12.0	12.2	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	12.3	12.3	12.9	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	11.5	11.6	12.2	Akron - W. Exchange

24-Hour $PM_{2.5}$			98th Percentile (24-hour)					Design Values			Base Year	Round 5 Modeling Results			
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average w/ 2007	2009	2012	2018	Key Site
Chicago - Washington HS	Cook	170310022	37.7	32.5	45.7	27.0	35.7	38.6	35.1	36.1	36.6	36	36	35	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	37.3	38.8	48.3	31.6	39.4	41.5	39.6	39.8	40.3	36	36	36	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	36.4	33.1	46.5	27.7	38.9	38.7	35.8	37.7	37.4	32	32	31	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	32.6	39.7	45.1	29.0	37.2	39.1	37.9	37.1	38.1	35	35	34	Chicago - Lawndale
McCook	Cook	170311016									43.0	39	39	38	McCook
Blue Island	Cook	170312001	39.6	38.5	43.8	28.1	35.1	40.6	36.8	35.7	37.7	34	34	33	Blue Island
Schiller Park	Cook	170313103		40.7	50.3	30.0	36.6	45.5	40.3	39.0	41.6	39	39	39	Schiller Park
Summit	Cook	170313301	38.4	42.4	49.1	27.4	36.7	43.3	39.6	37.7	40.2	38	38	37	Summit
Maywood	Cook	170316005	38.5	42.5	44.6	29.2	36.9	41.9	38.8	36.9	39.2	38	38	37	Maywood
Granite City	Madison	171191007	40.8	35.4	44.1	36.3	36.0	40.1	38.6	38.8	39.2	33	33	32	Granite City
E. St. Louis	St. Clair	171630010	32.6	30.2	39.6	29.2	33.1	34.1	33.0	34.0	33.7	28	28	28	E. St. Louis
Jeffersonville	Clark	180190005		28.4	45.5	35.9	43.3	37.0	36.6	41.6	38.4	29	31	31	Jeffersonville
Jasper	Dubois	180372001	39.5	30.0	41.2	31.6	39.5	36.9	34.3	37.4	36.2	28	29	28	Jasper
Gary - IITRI	Lake	180890022									39.0	34	34	35	Gary - IITRI
Gary - Burr School	Lake	180890026									39.0	33	34	32	Gary - Burr School
Gary	Lake	180890031			38.7	27.1	36.2	38.7	32.9	34.0	35.2	24	24	27	Gary
Indy-West Street	Marion	180970043									38.0	33	33	33	Indy-West Street
Indy-English Avenue	Marion	180970066									38.0	32	32	32	Indy-English Avenue
Indy-Washington Park	Marion	180970078	39.3	31.0	42.5	31.7	37.6	37.6	35.1	37.3	36.6	31	31	32	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	36.2	31.9	45.7	34.8	38.4	37.9	37.5	39.6	38.3	31	31	31	Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	36.7	31.3	40.3	33.5	37.2	36.1	35.0	37.0	36.0	28	28	29	Indy- Michigan Street
Luna Pier	Monroe	261150005	34.7	35.0	49.3	32.6	32.2	39.7	39.0	38.0	38.9	32	32	31	Luna Pier
Oak Park	Oakland	261250001	36.6	32.5	52.2	33.0	35.3	40.4	39.2	40.2	39.9	36	36	35	Oak Park
Port Huron	St. Clair	261470005	37.2	32.2	47.6	37.9	36.3	39.0	39.2	40.6	39.6	34	34	33	Port Huron
Ypsilanti	Washtenaw	261610008	38.8	31.5	52.1	31.3	34.5	40.8	38.3	39.3	39.5	35	35	34	Ypsilanti
Allen Park	Wayne	261630001	40.5	36.9	43.0	34.1	35.9	40.1	38.0	37.7	38.6	35	34	33	Allen Park
Southwest HS	Wayne	261630015	33.6	36.0	49.7	36.2	34.0	39.8	40.6	40.0	40.1	35	35	33	Southwest HS
Linwood	Wayne	261630016	46.2	38.3	51.8	36.9	34.8	45.4	42.3	41.2	43.0	39	39	38	Linwood
E 7 Mile	Wayne	261630019	37.1	35.0	52.3	36.2	33.0	41.5	41.2	40.5	41.0	38	38	37	E 7 Mile
Dearborn	Wayne	261630033	42.8	39.4	50.2	43.1	36.6	44.1	44.2	43.3	43.9	40	40	39	Dearborn
Wyandotte	Wayne	261630036	34.8	32.3	46.7	33.2	28.6	37.9	37.4	36.2	37.2	35	35	34	Wyandotte
Newberry	Wayne	261630038		36.8	57.5	28.6	33.4		39.1	39.8	42.7	38	37	36	Newberry
FIA	Wayne	261630039			43.9	32.4	34.8			37.0	39.7	33	33	31	FIA
Middleton	Butler	390170003	38.6	37.2	47.6	30.2	37.1	41.1	38.3	38.3	39.3	28	28	27	Middleton
Fairfield	Butler	390170016	34.8	32.2	43.4	35.2	34.5	36.8	36.9	37.7	37.1	27	28	27	Fairfield
	Butler	390170017	34.6	34.3	44.9			37.9	39.6		40.8	29	29	28	
Cleveland-28th Street	Cuyahoga	390350027	41.3	40.9	35.7	31.5	39.0	39.3	36.0	35.4	36.9	32	32	31	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	47.3	42.5	51.2	36.1	39.7	44.9	47.0	42.3	44.2	36	35	34	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	42.2	36.1	46.2	29.5	37.0	41.5	37.3	37.6	38.8	31	30	29	Cleveland-Broadway
Cleveland-GT Craig	Cuyahoga	390350060	45.5	42.2	49.5	31.0	38.7	45.7	40.9	39.7	42.1	37	37	35	Cleveland-GT Craig
Newburg Hts - Harvard Ave	Cuyahoga	390350065	39.1	36.1	47.9	27.8	39.1	41.0	37.3	38.3	38.9	31	30	30	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	39.2	35.1	45.0	34.0	34.2	39.8	38.0	37.7	38.5	33	32	31	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	37.0	35.5	44.9	34.0	35.5	39.1	38.1	38.1	38.5	31	31	30	Columbus - Ann Street
Cincinnait	Hamilton	390610006			45.0	33.3	34.7			37.7	40.6	27	28	27	Cincinnait
Cincinnati - Seymour	Hamilton	390610014	37.8	42.0	38.5	35.2	38.1	39.4	38.6	37.3	38.4	26	25	24	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	31.9	30.5	45.8	32.8	34.7	36.1	36.4	37.8	36.7	24	24	23	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	33.8	31.9	44.4	34.5	35.9	36.7	36.9	38.3	37.3	28	28	27	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	37.3	31.4	39.9	34.9	34.0	36.2	35.4	36.3	36.0	28	28	27	Sharonville
Norwood	Hamilton	390617001	37.1	34.6	47.1	34.0	33.7	39.6	38.6	38.3	38.8	30	30	29	Norwood
St. Bernard	Hamilton	390618001	35.8	33.9	51.4	36.1	35.4	40.4	40.5	41.0	40.6	30	30	29	St. Bernard
Steubenville	Jefferson	390810016	39.6	43.8	43.8	32.1	43.5	42.4	39.9	39.8	40.7	29	28	28	Steubenville
Mingo Junction	Jefferson	390811001	40.9	51.5	44.2	32.9	35.4	45.5	42.9	37.5	42.0	30	30	30	Mingo Junction
Dayton	Montgomery	391130032	42.7	32.5	45.0	30.3	36.9	40.1	35.9	37.4	37.8	30	30	30	Dayton
Canton - Dueber	Stark	391510017	34.2	36.3	47.6	32.2	33.4	39.4	38.7	37.7	38.6	28	28	27	Canton - Dueber
Akron - Brittain	Summit	391530017	36.9	36.9	45.2	31.5	33.3	39.7	37.9	36.7	38.1	30	30	29	Akron - Brittain
Green Bay - Est High	Brown	550090005	33.5	32.3	41.5	36.9	37.1	35.8	36.9	38.5	37.1	35	34	32	Green Bay - Est High
Madison	Dane	550250047	32.0	31.9	40.1	33.4	44.3	34.7	35.1	39.3	36.4	32	31	29	Madison
Milwaukee-Health Center	Milwaukee	550790010	33.2	38.4	38.7	40.7	40.6	36.8	39.3	40.0	38.7	35	34	33	Milwaukee-Health Center
Milwaukee-SER Hdqs	Milwaukee	550790026	29.6	28.7	41.5	42.6	39.8	33.3	37.6	41.3	37.4	34	34	33	Milwaukee-SER Hdqs
Milwaukee-Virginia FS	Milwaukee	550790043	39.2	41.4	37.1	44.0	38	39.2	40.8	39.7	39.9	36	36	36	Milwaukee-Virginia FS
Milwaukee- Fire Dept Hdqs	Milwaukee	550790099	33.7	38.9	37.1	38.3	40.7	36.6	38.1	38.7	37.8	33	32	32	Milwaukee- Fire Dept Hdqs
Waukesha	Waukesha	551330027	29.1	38.4	41.1	28.2	33.8	36.2	35.9	34.4	35.5	31	31	29	Waukesha

PM2.5 RRFs by Species and Season (2009)						
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
1703100521	IL	Cook	winter	so4	0.1772	0.9342
1703100521	IL	Cook	winter	no3	0.3099	1.0128
1703100521	IL	Cook	winter	ocm	0.2147	0.9942
1703100521	IL	Cook	winter	ec	0.0372	0.888
1703100521	IL	Cook	winter	soil	0.0242	1.1674
1703100521	IL	Cook	winter	nh4	0.1421	0.97
1703100521	IL	Cook	winter	pbw	0.0947	0.9678
1703100521	IL	Cook	spring	so4	0.32	0.8018
1703100521	IL	Cook	spring	no3	0.0609	0.9385
1703100521	IL	Cook	spring	ocm	0.2742	1.0629
1703100521	IL	Cook	spring	ec	0.0501	0.8712
1703100521	IL	Cook	spring	soil	0.0505	1.1796
1703100521	IL	Cook	spring	nh4	0.1203	0.8619
1703100521	IL	Cook	spring	pbw	0.0984	0.8492
1703100521	IL	Cook	summer	so4	0.3089	0.725
1703100521	IL	Cook	summer	no3	0	1.0124
1703100521	IL	Cook	summer	ocm	0.1599	1.069
1703100521	IL	Cook	summer	ec	0.0351	0.8683
1703100521	IL	Cook	summer	soil	0.0318	1.204
1703100521	IL	Cook	summer	nh4	0.0932	0.7354
1703100521	IL	Cook	summer	pbw	0.094	0.7217
1703100521	IL	Cook	fall	so4	0.1872	0.9151
1703100521	IL	Cook	fall	no3	0.1628	0.9408
1703100521	IL	Cook	fall	ocm	0.2389	1.0091
1703100521	IL	Cook	fall	ec	0.0403	0.8623
1703100521	IL	Cook	fall	soil	0.0284	1.1443
1703100521	IL	Cook	fall	nh4	0.1062	0.9247
1703100521	IL	Cook	fall	pbw	0.0614	0.9233
1711910071	IL	Madison	winter	so4	0.213	0.9195
1711910071	IL	Madison	winter	no3	0.2705	1.0306
1711910071	IL	Madison	winter	ocm	0.2093	0.9289
1711910071	IL	Madison	winter	ec	0.0434	0.9083
1711910071	IL	Madison	winter	soil	0.0306	1.1782
1711910071	IL	Madison	winter	nh4	0.1528	0.9513
1711910071	IL	Madison	winter	pbw	0.0804	0.9243
1711910071	IL	Madison	spring	so4	0.3194	0.7717
1711910071	IL	Madison	spring	no3	0.0189	0.8611
1711910071	IL	Madison	spring	ocm	0.2455	1.1103
1711910071	IL	Madison	spring	ec	0.0564	1.0046
1711910071	IL	Madison	spring	soil	0.0459	1.2252
1711910071	IL	Madison	spring	nh4	0.1121	0.7894
1711910071	IL	Madison	spring	pbw	0.1085	0.7783
1711910071	IL	Madison	summer	so4	0.313	0.705
1711910071	IL	Madison	summer	no3	0	0.884
1711910071	IL	Madison	summer	ocm	0.153	1.1546
1711910071	IL	Madison	summer	ec	0.0345	1.0513
1711910071	IL	Madison	summer	soil	0.0302	1.2532
1711910071	IL	Madison	summer	nh4	0.102	0.7409
1711910071	IL	Madison	summer	pbw	0.1096	0.7133
1711910071	IL	Madison	fall	so4	0.2058	0.9037
1711910071	IL	Madison	fall	no3	0.1308	0.9426
1711910071	IL	Madison	fall	ocm	0.259	1.0233
1711910071	IL	Madison	fall	ec	0.0563	0.9248
1711910071	IL	Madison	fall	soil	0.0549	1.1412
1711910071	IL	Madison	fall	nh4	0.1073	0.9185
1711910071	IL	Madison	fall	pbw	0.0655	0.918

Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
1803720011	IN	Dubois	winter	so4	0.2669	0.8833
1803720011	IN	Dubois	winter	no3	0.2548	0.9526
1803720011	IN	Dubois	winter	ocm	0.1747	0.9374
1803720011	IN	Dubois	winter	ec	0.0313	0.9319
1803720011	IN	Dubois	winter	soil	0.0192	1.1349
1803720011	IN	Dubois	winter	nh4	0.1646	0.9069
1803720011	IN	Dubois	winter	pbw	0.0885	0.9006
1803720011	IN	Dubois	spring	so4	0.4141	0.6808
1803720011	IN	Dubois	spring	no3	0.0022	0.8106
1803720011	IN	Dubois	spring	ocm	0.178	0.9997
1803720011	IN	Dubois	spring	ec	0.0324	0.9083
1803720011	IN	Dubois	spring	soil	0.0218	1.1284
1803720011	IN	Dubois	spring	nh4	0.1432	0.7075
1803720011	IN	Dubois	spring	pbw	0.1556	0.6916
1803720011	IN	Dubois	summer	so4	0.3687	0.644
1803720011	IN	Dubois	summer	no3	0	0.8029
1803720011	IN	Dubois	summer	ocm	0.1174	1.0136
1803720011	IN	Dubois	summer	ec	0.0207	0.913
1803720011	IN	Dubois	summer	soil	0.0213	1.1988
1803720011	IN	Dubois	summer	nh4	0.1168	0.6789
1803720011	IN	Dubois	summer	pbw	0.1246	0.6613
1803720011	IN	Dubois	fall	so4	0.2964	0.8232
1803720011	IN	Dubois	fall	no3	0.138	0.8797
1803720011	IN	Dubois	fall	ocm	0.2116	0.9861
1803720011	IN	Dubois	fall	ec	0.0437	0.9019
1803720011	IN	Dubois	fall	soil	0.03	1.1387
1803720011	IN	Dubois	fall	nh4	0.1449	0.8444
1803720011	IN	Dubois	fall	pbw	0.0941	0.8558
1809700811	IN	Marion	winter	so4	0.2358	0.9192
1809700811	IN	Marion	winter	no3	0.2729	0.9769
1809700811	IN	Marion	winter	ocm	0.1851	0.9546
1809700811	IN	Marion	winter	ec	0.0385	0.8647
1809700811	IN	Marion	winter	soil	0.0239	1.0835
1809700811	IN	Marion	winter	nh4	0.1561	0.9446
1809700811	IN	Marion	winter	pbw	0.0877	0.944
1809700811	IN	Marion	spring	so4	0.3745	0.6868
1809700811	IN	Marion	spring	no3	0.0167	0.8082
1809700811	IN	Marion	spring	ocm	0.2034	0.9881
1809700811	IN	Marion	spring	ec	0.0447	0.8547
1809700811	IN	Marion	spring	soil	0.0376	1.0625
1809700811	IN	Marion	spring	nh4	0.1313	0.7182
1809700811	IN	Marion	spring	pbw	0.1309	0.7056
1809700811	IN	Marion	summer	so4	0.3582	0.6529
1809700811	IN	Marion	summer	no3	0	0.8099
1809700811	IN	Marion	summer	ocm	0.1231	1.0043
1809700811	IN	Marion	summer	ec	0.03	0.8444
1809700811	IN	Marion	summer	soil	0.0253	1.0918
1809700811	IN	Marion	summer	nh4	0.1114	0.6854
1809700811	IN	Marion	summer	pbw	0.1163	0.6674
1809700811	IN	Marion	fall	so4	0.2751	0.8538
1809700811	IN	Marion	fall	no3	0.149	0.9452
1809700811	IN	Marion	fall	ocm	0.223	0.9648
1809700811	IN	Marion	fall	ec	0.0525	0.8412
1809700811	IN	Marion	fall	soil	0.0358	1.089
1809700811	IN	Marion	fall	nh4	0.1378	0.8905
1809700811	IN	Marion	fall	pbw	0.0865	0.8888

Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
2616300331	MI	Wayne	winter	so4	0.1587	0.9206
2616300331	MI	Wayne	winter	no3	0.2394	0.9813
2616300331	MI	Wayne	winter	ocm	0.3193	1.0781
2616300331	MI	Wayne	winter	ec	0.0383	0.9279
2616300331	MI	Wayne	winter	soil	0.0541	1.0206
2616300331	MI	Wayne	winter	nh4	0.1188	0.9518
2616300331	MI	Wayne	winter	pbw	0.0714	0.9566
2616300331	MI	Wayne	spring	so4	0.3383	0.7398
2616300331	MI	Wayne	spring	no3	0.0259	0.8787
2616300331	MI	Wayne	spring	ocm	0.3543	1.0234
2616300331	MI	Wayne	spring	ec	0.0504	0.8671
2616300331	MI	Wayne	spring	soil	0.0915	1.0153
2616300331	MI	Wayne	spring	nh4	0.1191	0.7818
2616300331	MI	Wayne	spring	pbw	0.1126	0.7619
2616300331	MI	Wayne	summer	so4	0.3311	0.6681
2616300331	MI	Wayne	summer	no3	0	0.8431
2616300331	MI	Wayne	summer	ocm	0.2297	1.0029
2616300331	MI	Wayne	summer	ec	0.0362	0.8332
2616300331	MI	Wayne	summer	soil	0.061	1.0177
2616300331	MI	Wayne	summer	nh4	0.1027	0.6974
2616300331	MI	Wayne	summer	pbw	0.1073	0.6754
2616300331	MI	Wayne	fall	so4	0.1898	0.854
2616300331	MI	Wayne	fall	no3	0.1075	0.9367
2616300331	MI	Wayne	fall	ocm	0.3689	1.0607
2616300331	MI	Wayne	fall	ec	0.0546	0.8862
2616300331	MI	Wayne	fall	soil	0.1676	1.0317
2616300331	MI	Wayne	fall	nh4	0.0866	0.8919
2616300331	MI	Wayne	fall	pbw	0.0553	0.8821
3903500381	OH	Cuyahoga	winter	so4	0.2117	0.8993
3903500381	OH	Cuyahoga	winter	no3	0.2665	0.9856
3903500381	OH	Cuyahoga	winter	ocm	0.2048	0.9716
3903500381	OH	Cuyahoga	winter	ec	0.0413	0.8903
3903500381	OH	Cuyahoga	winter	soil	0.0465	1.0959
3903500381	OH	Cuyahoga	winter	nh4	0.1459	0.9416
3903500381	OH	Cuyahoga	winter	pbw	0.0832	0.9541
3903500381	OH	Cuyahoga	spring	so4	0.3334	0.7145
3903500381	OH	Cuyahoga	spring	no3	0.0374	0.8393
3903500381	OH	Cuyahoga	spring	ocm	0.2068	1.0899
3903500381	OH	Cuyahoga	spring	ec	0.052	0.9362
3903500381	OH	Cuyahoga	spring	soil	0.0697	1.0601
3903500381	OH	Cuyahoga	spring	nh4	0.1256	0.7666
3903500381	OH	Cuyahoga	spring	pbw	0.115	0.7761
3903500381	OH	Cuyahoga	summer	so4	0.3241	0.6303
3903500381	OH	Cuyahoga	summer	no3	0	0.89
3903500381	OH	Cuyahoga	summer	ocm	0.1306	1.0998
3903500381	OH	Cuyahoga	summer	ec	0.0419	0.9354
3903500381	OH	Cuyahoga	summer	soil	0.0583	1.0906
3903500381	OH	Cuyahoga	summer	nh4	0.1074	0.7038
3903500381	OH	Cuyahoga	summer	pbw	0.1183	0.6674
3903500381	OH	Cuyahoga	fall	so4	0.2055	0.8193
3903500381	OH	Cuyahoga	fall	no3	0.1275	0.9189
3903500381	OH	Cuyahoga	fall	ocm	0.2234	1.0245
3903500381	OH	Cuyahoga	fall	ec	0.0499	0.8913
3903500381	OH	Cuyahoga	fall	soil	0.0675	1.0927
3903500381	OH	Cuyahoga	fall	nh4	0.1034	0.8615
3903500381	OH	Cuyahoga	fall	pbw	0.0637	0.8564

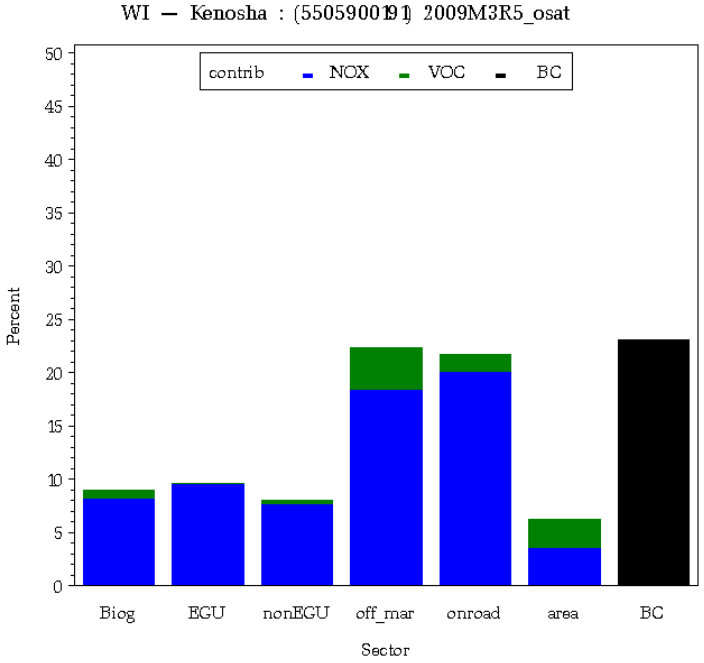
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3904900241	OH	Franklin	winter	so4	0.2555	0.8622
3904900241	OH	Franklin	winter	no3	0.2373	1.0002
3904900241	OH	Franklin	winter	ocm	0.2082	0.974
3904900241	OH	Franklin	winter	ec	0.0375	0.8537
3904900241	OH	Franklin	winter	soil	0.0259	1.0844
3904900241	OH	Franklin	winter	nh4	0.1495	0.9261
3904900241	OH	Franklin	winter	pbw	0.0861	0.9274
3904900241	OH	Franklin	spring	so4	0.3754	0.6615
3904900241	OH	Franklin	spring	no3	0.0176	0.8436
3904900241	OH	Franklin	spring	ocm	0.2069	1.062
3904900241	OH	Franklin	spring	ec	0.0405	0.8678
3904900241	OH	Franklin	spring	soil	0.0371	1.0551
3904900241	OH	Franklin	spring	nh4	0.1296	0.7212
3904900241	OH	Franklin	spring	pbw	0.128	0.6992
3904900241	OH	Franklin	summer	so4	0.3703	0.622
3904900241	OH	Franklin	summer	no3	0	0.9056
3904900241	OH	Franklin	summer	ocm	0.1343	1.0654
3904900241	OH	Franklin	summer	ec	0.0311	0.8565
3904900241	OH	Franklin	summer	soil	0.0267	1.0667
3904900241	OH	Franklin	summer	nh4	0.1142	0.7021
3904900241	OH	Franklin	summer	pbw	0.1186	0.6614
3904900241	OH	Franklin	fall	so4	0.2692	0.8119
3904900241	OH	Franklin	fall	no3	0.1186	0.9099
3904900241	OH	Franklin	fall	ocm	0.2489	1.019
3904900241	OH	Franklin	fall	ec	0.0533	0.8371
3904900241	OH	Franklin	fall	soil	0.0423	1.0924
3904900241	OH	Franklin	fall	nh4	0.1217	0.8539
3904900241	OH	Franklin	fall	pbw	0.0821	0.8519
3906100141	OH	Hamilton	winter	so4	0.2685	0.8104
3906100141	OH	Hamilton	winter	no3	0.2378	1.0886
3906100141	OH	Hamilton	winter	ocm	0.19	0.961
3906100141	OH	Hamilton	winter	ec	0.035	0.8969
3906100141	OH	Hamilton	winter	soil	0.0229	1.4146
3906100141	OH	Hamilton	winter	nh4	0.1583	0.9077
3906100141	OH	Hamilton	winter	pbw	0.0874	0.8687
3906100141	OH	Hamilton	spring	so4	0.3583	0.6331
3906100141	OH	Hamilton	spring	no3	0.0025	1.0155
3906100141	OH	Hamilton	spring	ocm	0.1986	1.0798
3906100141	OH	Hamilton	spring	ec	0.0466	0.9228
3906100141	OH	Hamilton	spring	soil	0.0289	1.3785
3906100141	OH	Hamilton	spring	nh4	0.1215	0.6968
3906100141	OH	Hamilton	spring	pbw	0.128	0.6307
3906100141	OH	Hamilton	summer	so4	0.3722	0.577
3906100141	OH	Hamilton	summer	no3	0	1.0923
3906100141	OH	Hamilton	summer	ocm	0.121	1.082
3906100141	OH	Hamilton	summer	ec	0.0309	0.9099
3906100141	OH	Hamilton	summer	soil	0.0199	1.537
3906100141	OH	Hamilton	summer	nh4	0.1178	0.6441
3906100141	OH	Hamilton	summer	pbw	0.1261	0.5734
3906100141	OH	Hamilton	fall	so4	0.2608	0.7754
3906100141	OH	Hamilton	fall	no3	0.1184	0.9857
3906100141	OH	Hamilton	fall	ocm	0.213	1.0235
3906100141	OH	Hamilton	fall	ec	0.0512	0.8876
3906100141	OH	Hamilton	fall	soil	0.0328	1.4007
3906100141	OH	Hamilton	fall	nh4	0.1254	0.846
3906100141	OH	Hamilton	fall	pbw	0.0828	0.8172

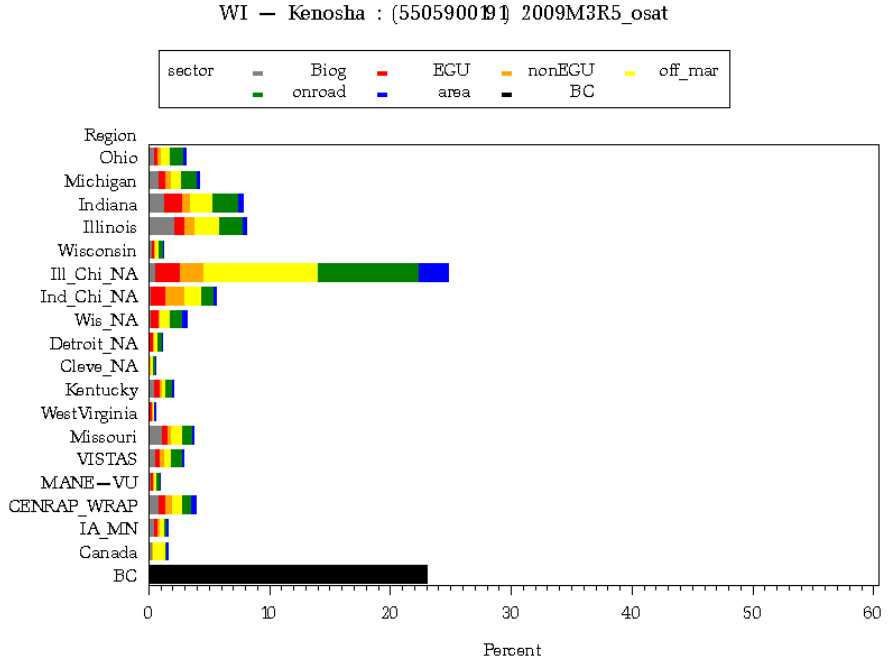
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3908110011	OH	Jefferson	winter	so4	0.2367	0.8217
3908110011	OH	Jefferson	winter	no3	0.1709	1.0522
3908110011	OH	Jefferson	winter	ocm	0.3288	0.8819
3908110011	OH	Jefferson	winter	ec	0.0435	0.9091
3908110011	OH	Jefferson	winter	soil	0.0272	0.4368
3908110011	OH	Jefferson	winter	nh4	0.1199	0.8904
3908110011	OH	Jefferson	winter	pbw	0.073	0.8583
3908110011	OH	Jefferson	spring	so4	0.3508	0.6666
3908110011	OH	Jefferson	spring	no3	0.0154	0.9156
3908110011	OH	Jefferson	spring	ocm	0.3078	0.9995
3908110011	OH	Jefferson	spring	ec	0.0395	0.9853
3908110011	OH	Jefferson	spring	soil	0.0407	0.4844
3908110011	OH	Jefferson	spring	nh4	0.114	0.7054
3908110011	OH	Jefferson	spring	pbw	0.1095	0.6713
3908110011	OH	Jefferson	summer	so4	0.3779	0.6156
3908110011	OH	Jefferson	summer	no3	0	1.0837
3908110011	OH	Jefferson	summer	ocm	0.2098	1.0145
3908110011	OH	Jefferson	summer	ec	0.0308	0.9689
3908110011	OH	Jefferson	summer	soil	0.0323	0.3632
3908110011	OH	Jefferson	summer	nh4	0.1065	0.6428
3908110011	OH	Jefferson	summer	pbw	0.1007	0.625
3908110011	OH	Jefferson	fall	so4	0.2315	0.7694
3908110011	OH	Jefferson	fall	no3	0.0702	1.0302
3908110011	OH	Jefferson	fall	ocm	0.372	0.9312
3908110011	OH	Jefferson	fall	ec	0.051	0.9086
3908110011	OH	Jefferson	fall	soil	0.0344	0.4555
3908110011	OH	Jefferson	fall	nh4	0.0859	0.8284
3908110011	OH	Jefferson	fall	pbw	0.0629	0.7951
3911300321	OH	Montgomer	winter	so4	0.2613	0.8598
3911300321	OH	Montgomer	winter	no3	0.2407	1.029
3911300321	OH	Montgomer	winter	ocm	0.1954	0.9442
3911300321	OH	Montgomer	winter	ec	0.036	0.8746
3911300321	OH	Montgomer	winter	soil	0.0259	1.1295
3911300321	OH	Montgomer	winter	nh4	0.1531	0.9304
3911300321	OH	Montgomer	winter	pbw	0.0876	0.9205
3911300321	OH	Montgomer	spring	so4	0.3659	0.6606
3911300321	OH	Montgomer	spring	no3	0.0163	0.8639
3911300321	OH	Montgomer	spring	ocm	0.1895	1.0976
3911300321	OH	Montgomer	spring	ec	0.0442	0.9417
3911300321	OH	Montgomer	spring	soil	0.0253	1.0873
3911300321	OH	Montgomer	spring	nh4	0.1313	0.7149
3911300321	OH	Montgomer	spring	pbw	0.1326	0.6839
3911300321	OH	Montgomer	summer	so4	0.375	0.6234
3911300321	OH	Montgomer	summer	no3	0	0.9474
3911300321	OH	Montgomer	summer	ocm	0.128	1.1047
3911300321	OH	Montgomer	summer	ec	0.029	0.9496
3911300321	OH	Montgomer	summer	soil	0.0205	1.1299
3911300321	OH	Montgomer	summer	nh4	0.1114	0.6931
3911300321	OH	Montgomer	summer	pbw	0.1114	0.6482
3911300321	OH	Montgomer	fall	so4	0.3062	0.8033
3911300321	OH	Montgomer	fall	no3	0.1012	0.9634
3911300321	OH	Montgomer	fall	ocm	0.2221	1.0158
3911300321	OH	Montgomer	fall	ec	0.0514	0.877
3911300321	OH	Montgomer	fall	soil	0.028	1.1391
3911300321	OH	Montgomer	fall	nh4	0.1352	0.8625
3911300321	OH	Montgomer	fall	pbw	0.0982	0.8475

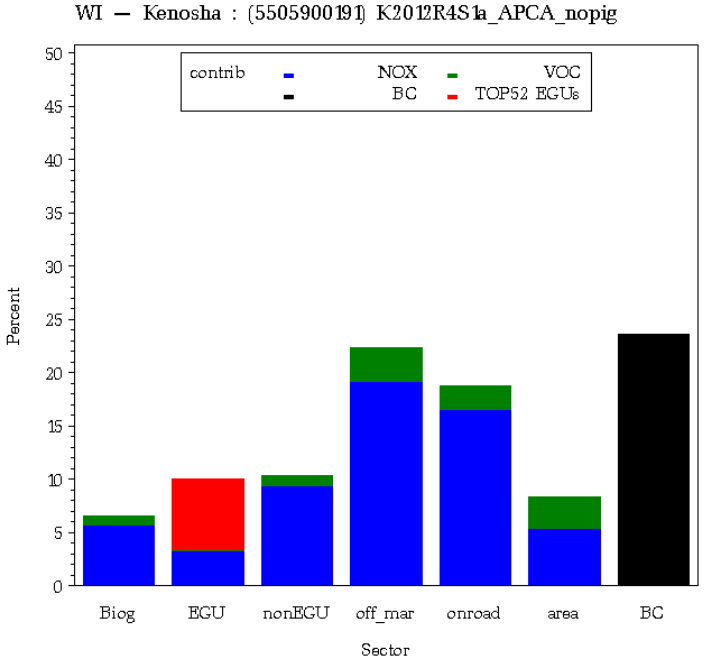
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3915100171	OH	Stark	winter	so4	0.2362	0.8558
3915100171	OH	Stark	winter	no3	0.2234	1.0222
3915100171	OH	Stark	winter	ocm	0.2478	0.9255
3915100171	OH	Stark	winter	ec	0.0414	0.8866
3915100171	OH	Stark	winter	soil	0.0334	1.099
3915100171	OH	Stark	winter	nh4	0.1376	0.925
3915100171	OH	Stark	winter	pbw	0.0802	0.9155
3915100171	OH	Stark	spring	so4	0.3581	0.6834
3915100171	OH	Stark	spring	no3	0.0236	0.855
3915100171	OH	Stark	spring	ocm	0.221	1.0892
3915100171	OH	Stark	spring	ec	0.0501	1.0017
3915100171	OH	Stark	spring	soil	0.058	1.0528
3915100171	OH	Stark	spring	nh4	0.1288	0.7264
3915100171	OH	Stark	spring	pbw	0.1256	0.7009
3915100171	OH	Stark	summer	so4	0.3621	0.6277
3915100171	OH	Stark	summer	no3	0	0.8203
3915100171	OH	Stark	summer	ocm	0.1483	1.0984
3915100171	OH	Stark	summer	ec	0.0403	1.016
3915100171	OH	Stark	summer	soil	0.037	1.0781
3915100171	OH	Stark	summer	nh4	0.1157	0.6739
3915100171	OH	Stark	summer	pbw	0.124	0.651
3915100171	OH	Stark	fall	so4	0.2293	0.8041
3915100171	OH	Stark	fall	no3	0.1262	0.9363
3915100171	OH	Stark	fall	ocm	0.2722	1.0226
3915100171	OH	Stark	fall	ec	0.0545	0.9202
3915100171	OH	Stark	fall	soil	0.0461	1.0959
3915100171	OH	Stark	fall	nh4	0.1105	0.8549
3915100171	OH	Stark	fall	pbw	0.0706	0.8428
3915300171	OH	Summit	winter	so4	0.2511	0.8771
3915300171	OH	Summit	winter	no3	0.2376	1.0052
3915300171	OH	Summit	winter	ocm	0.2185	0.9429
3915300171	OH	Summit	winter	ec	0.0334	0.8677
3915300171	OH	Summit	winter	soil	0.0255	1.0835
3915300171	OH	Summit	winter	nh4	0.1489	0.9374
3915300171	OH	Summit	winter	pbw	0.0851	0.945
3915300171	OH	Summit	spring	so4	0.387	0.7046
3915300171	OH	Summit	spring	no3	0.0072	0.8466
3915300171	OH	Summit	spring	ocm	0.1901	1.0967
3915300171	OH	Summit	spring	ec	0.035	0.9482
3915300171	OH	Summit	spring	soil	0.0304	1.0524
3915300171	OH	Summit	spring	nh4	0.1294	0.7521
3915300171	OH	Summit	spring	pbw	0.1342	0.7384
3915300171	OH	Summit	summer	so4	0.3694	0.6378
3915300171	OH	Summit	summer	no3	0	0.8587
3915300171	OH	Summit	summer	ocm	0.1417	1.1077
3915300171	OH	Summit	summer	ec	0.0332	0.9506
3915300171	OH	Summit	summer	soil	0.0198	1.0744
3915300171	OH	Summit	summer	nh4	0.1121	0.6961
3915300171	OH	Summit	summer	pbw	0.1146	0.6691
3915300171	OH	Summit	fall	so4	0.2443	0.8074
3915300171	OH	Summit	fall	no3	0.1175	0.9392
3915300171	OH	Summit	fall	ocm	0.2636	1.0252
3915300171	OH	Summit	fall	ec	0.0623	0.8883
3915300171	OH	Summit	fall	soil	0.0494	1.086
3915300171	OH	Summit	fall	nh4	0.109	0.8622
3915300171	OH	Summit	fall	pbw	0.0723	0.8506

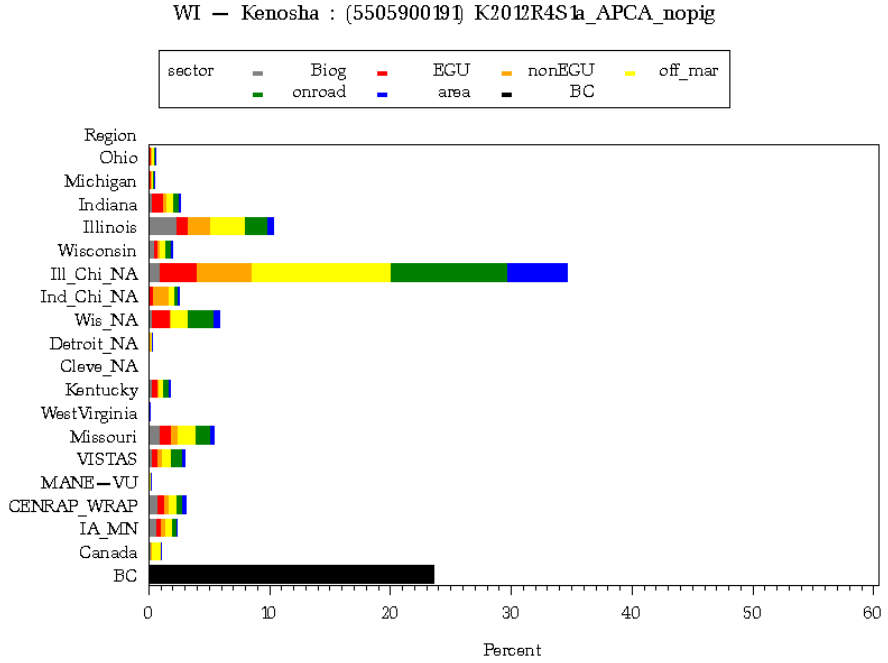
APPENDIX II

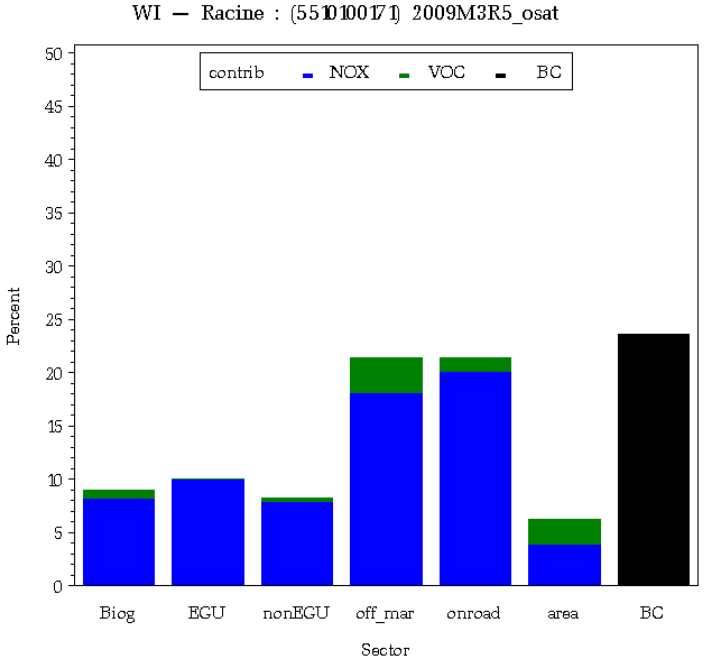
Ozone Source Apportionment Modeling Results


WI — Kenosha : (550590019) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Kenosha : (550590019) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Kenosha : (550590019) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Kenosha : (550590019) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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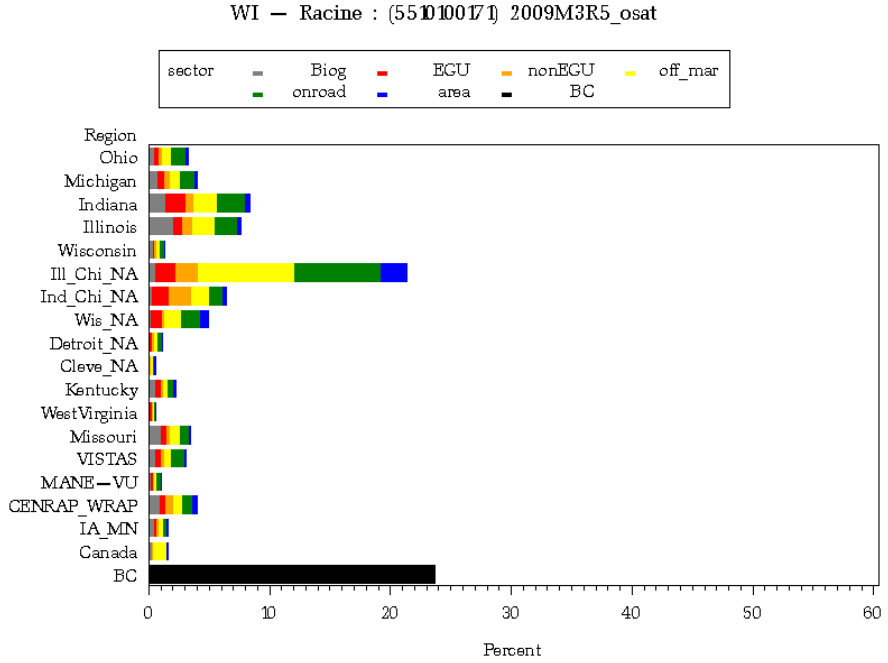
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector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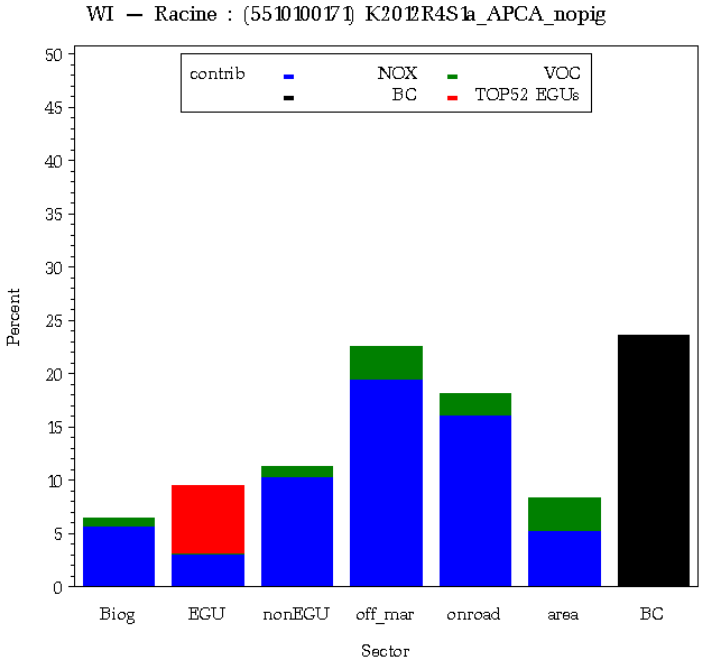
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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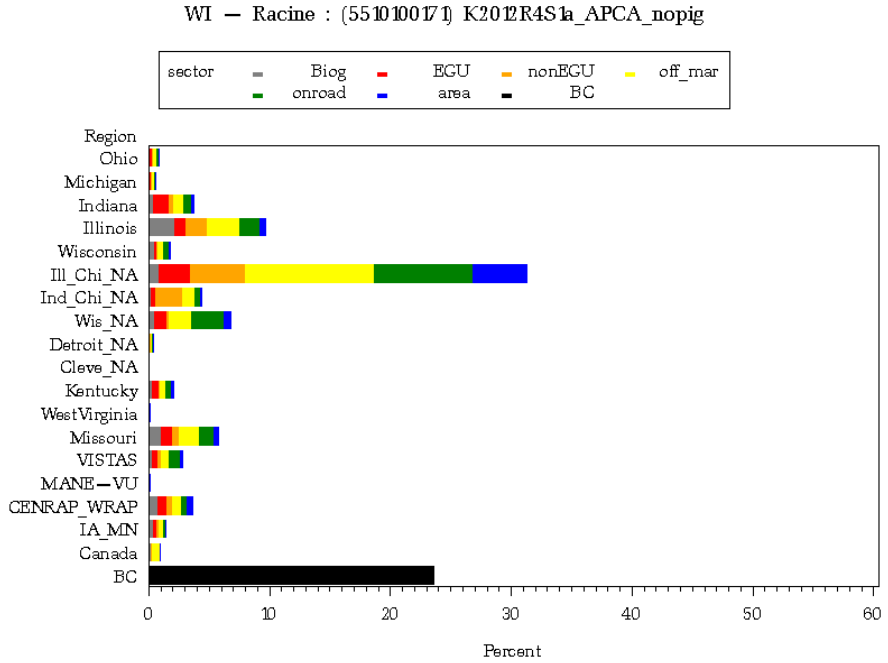
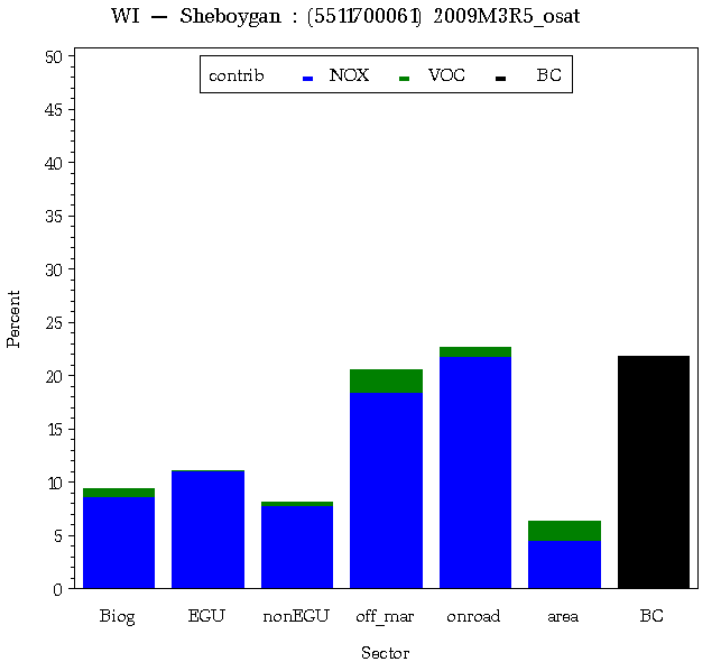
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Racine : (551010017) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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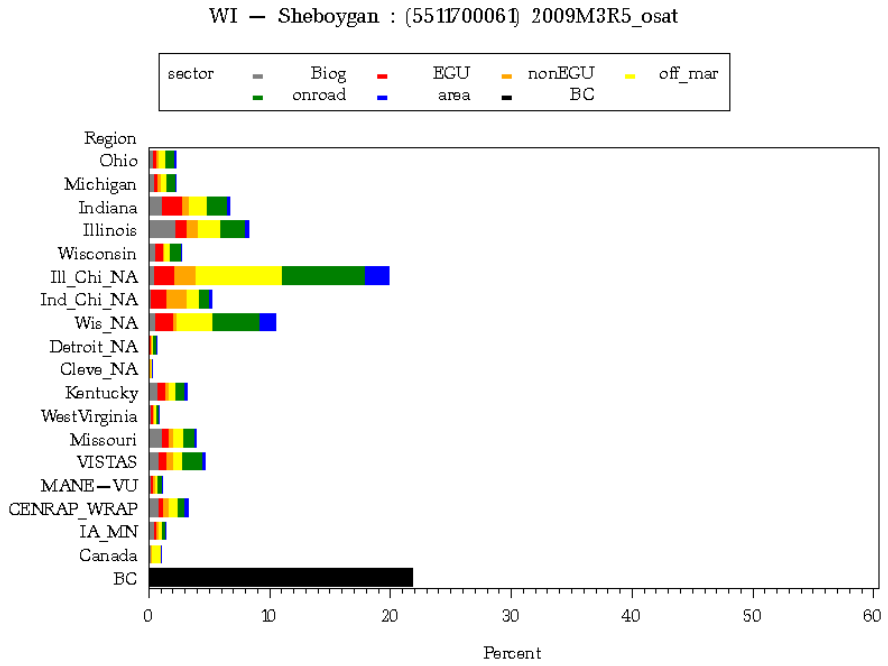
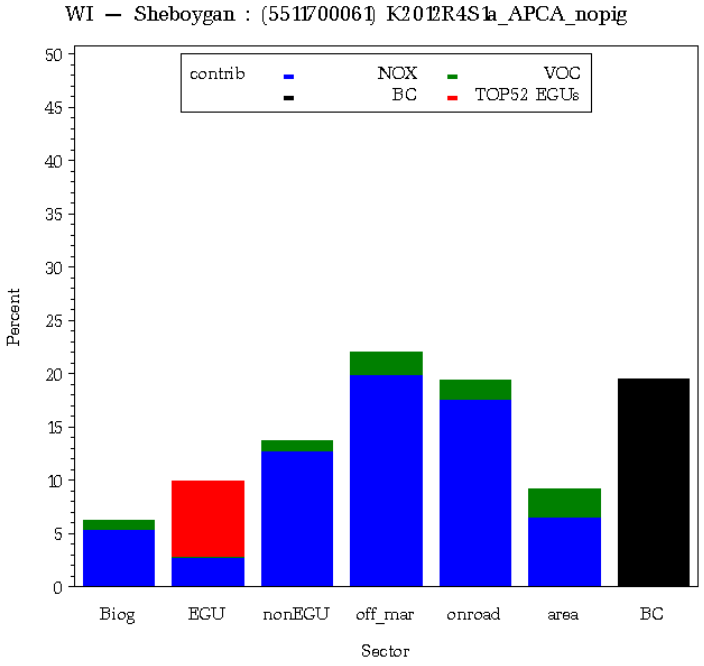
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Sheboygan : (551700061) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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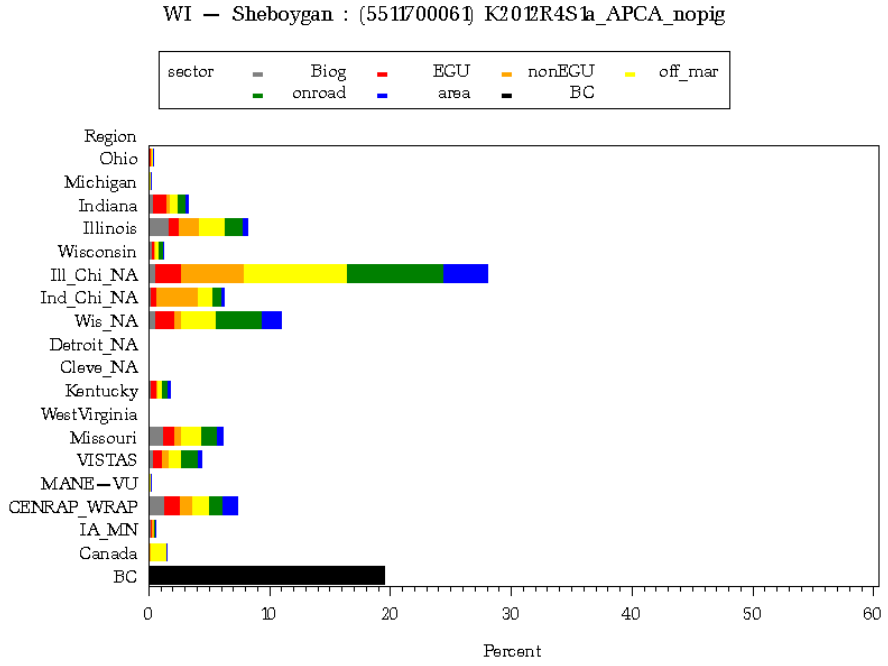
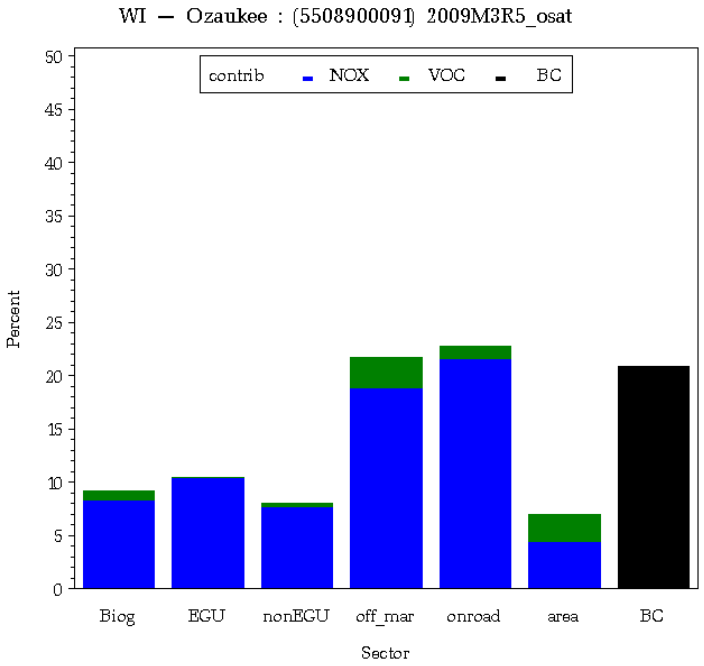
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Sheboygan : (551700061) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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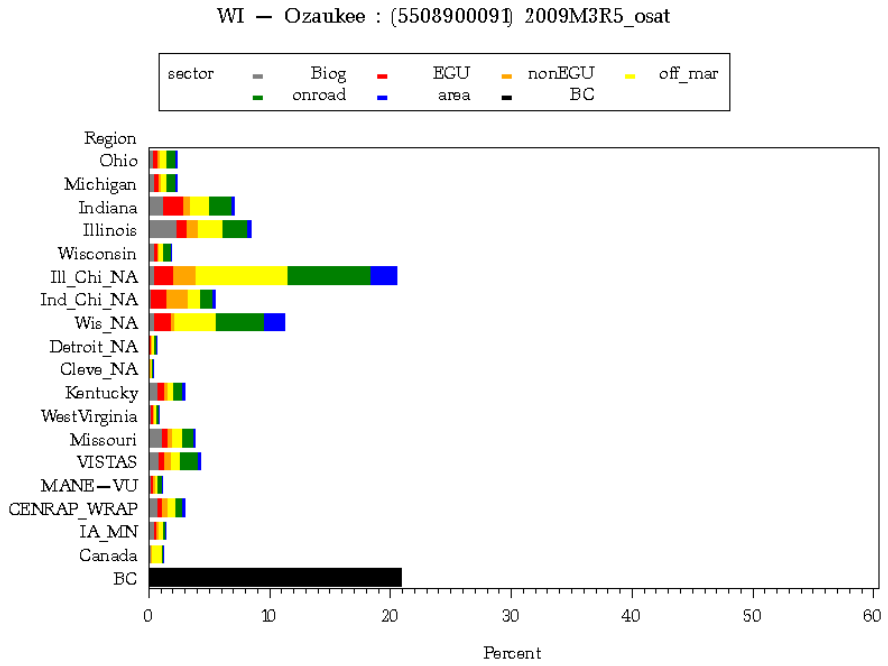
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector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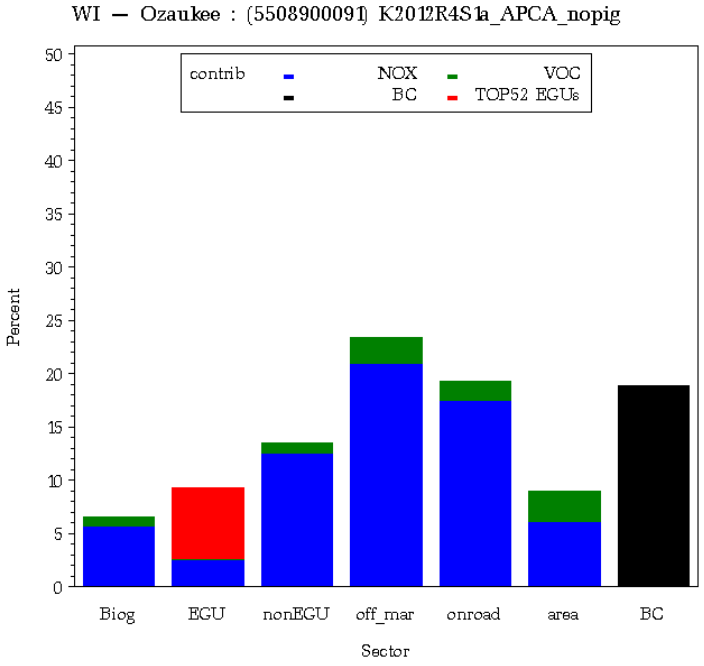
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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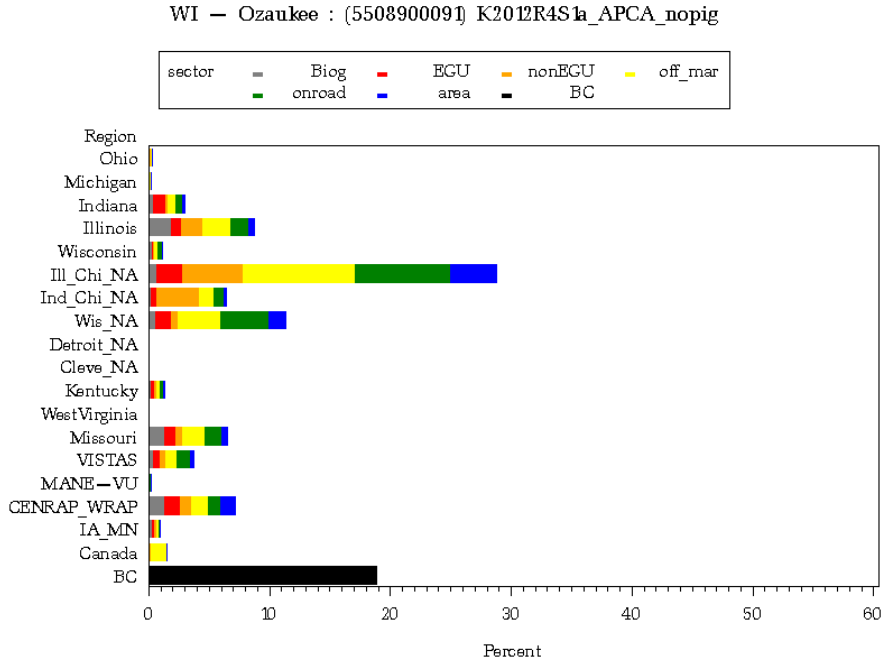
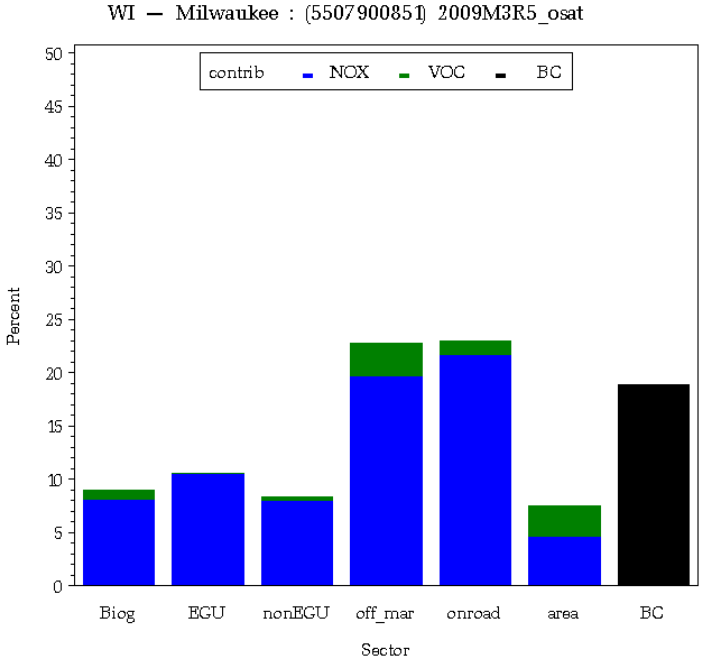
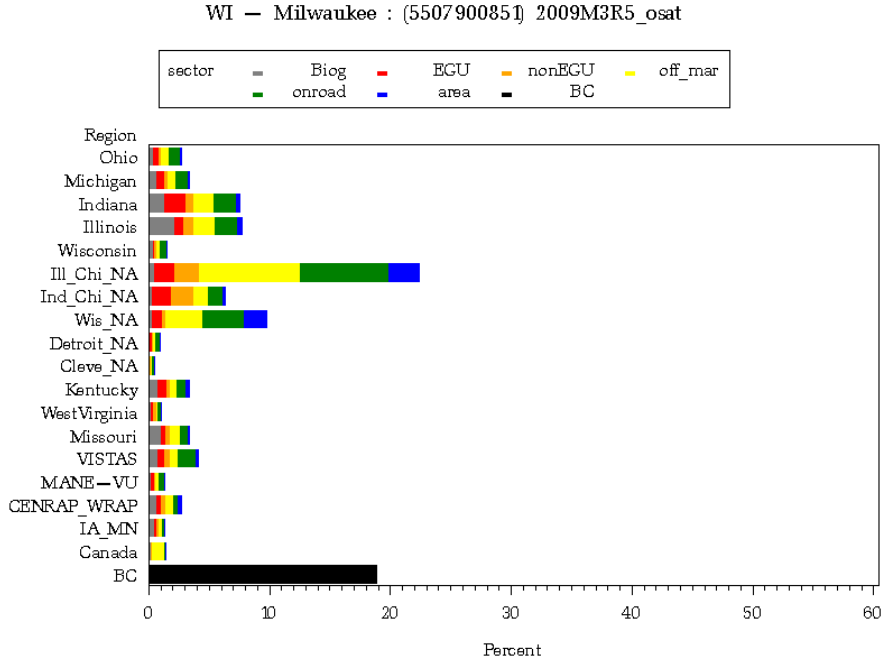
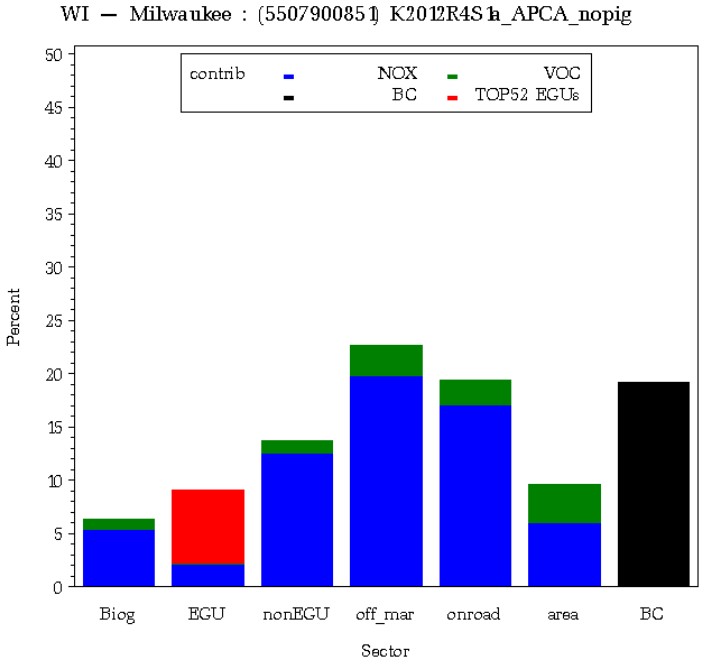
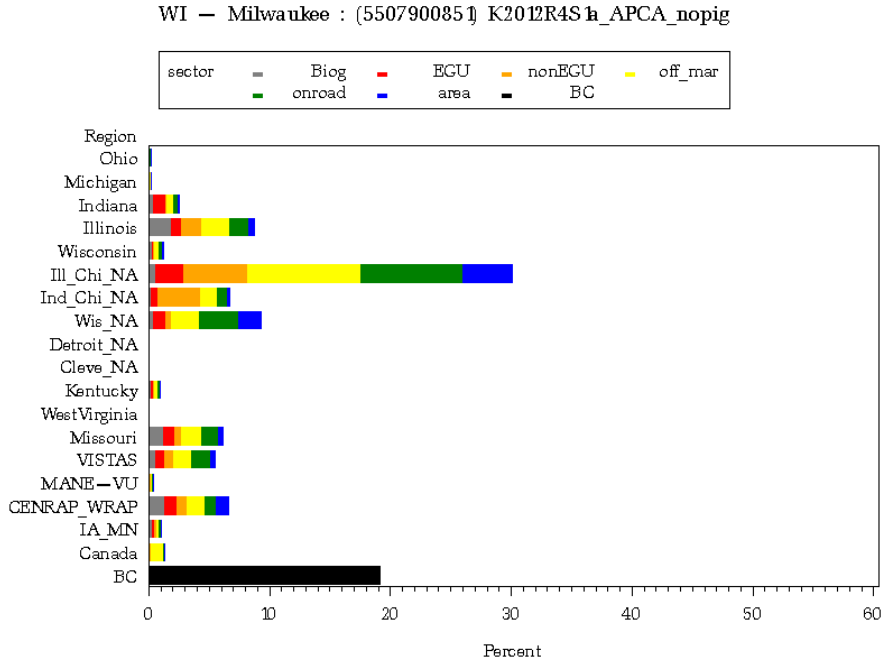
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

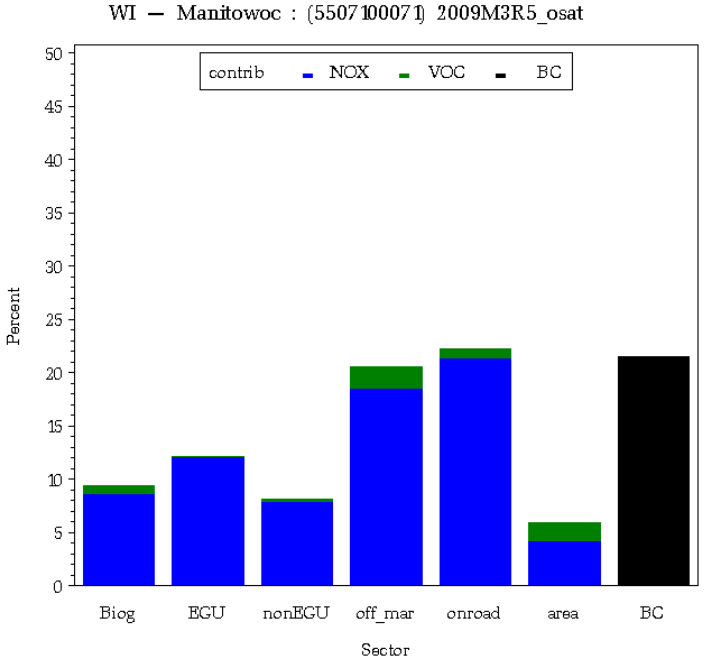

WI — Ozaukee : (5508900091) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

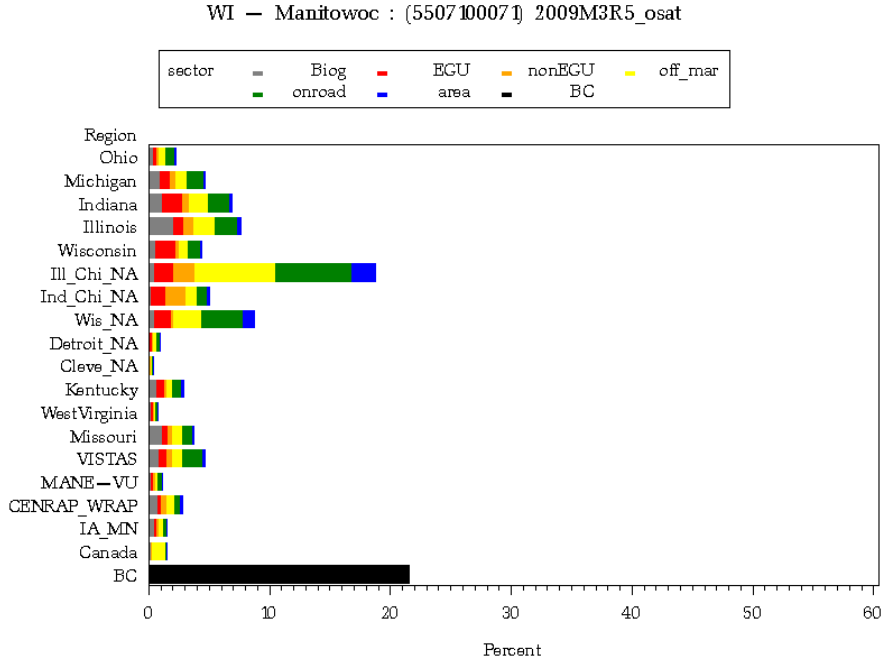

WI — Milwaukee : (550790085 1) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

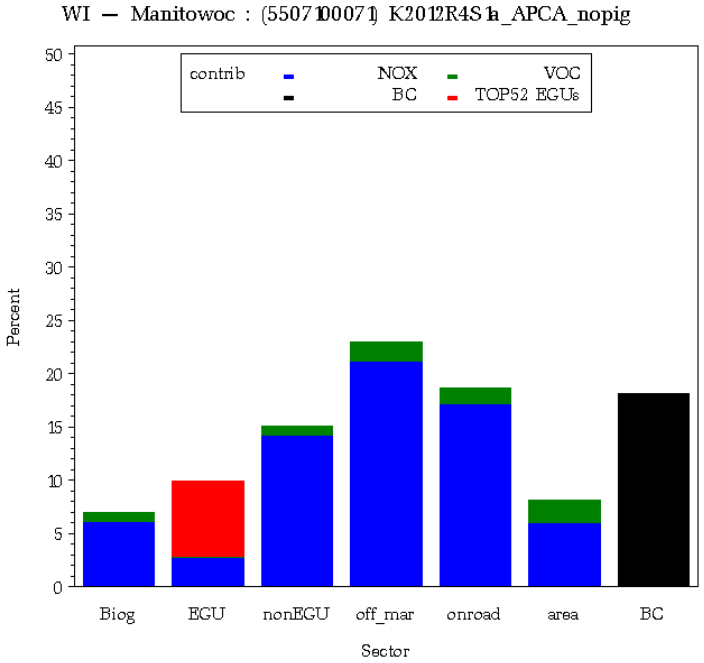

WI — Milwaukee : (550790085 1) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

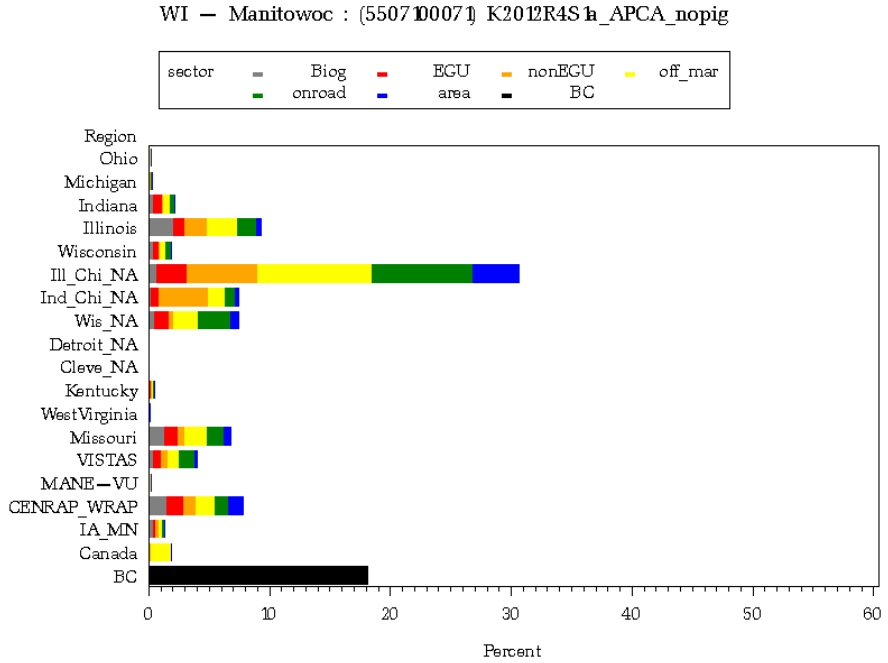

WI — Milwaukee : (550790085 1) K2012R4S ha_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

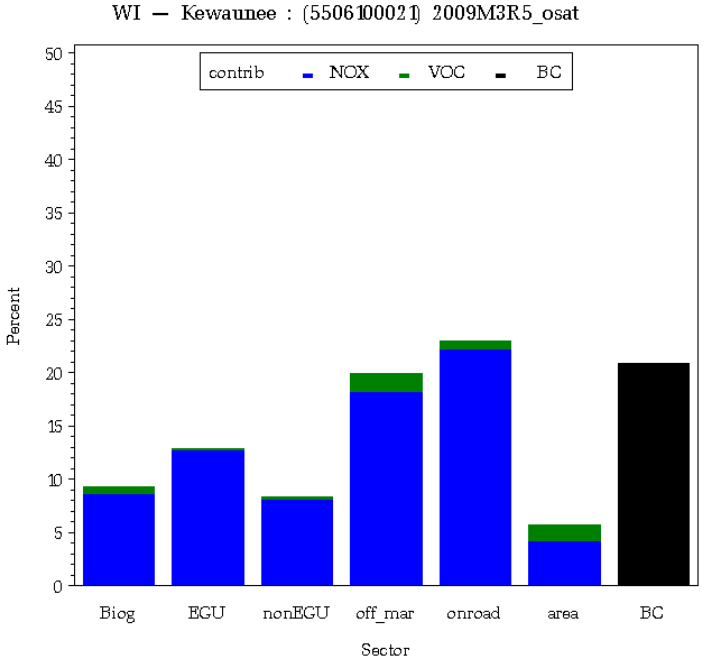

WI — Milwaukee : (550790085 1) K2012R4S ha_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

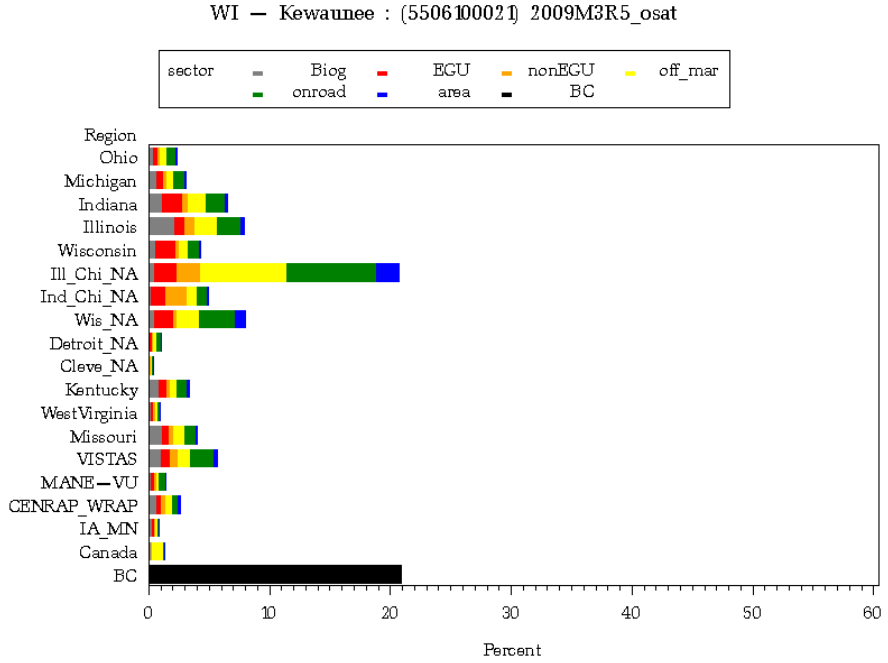

WI — Manitowoc : (550710071) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

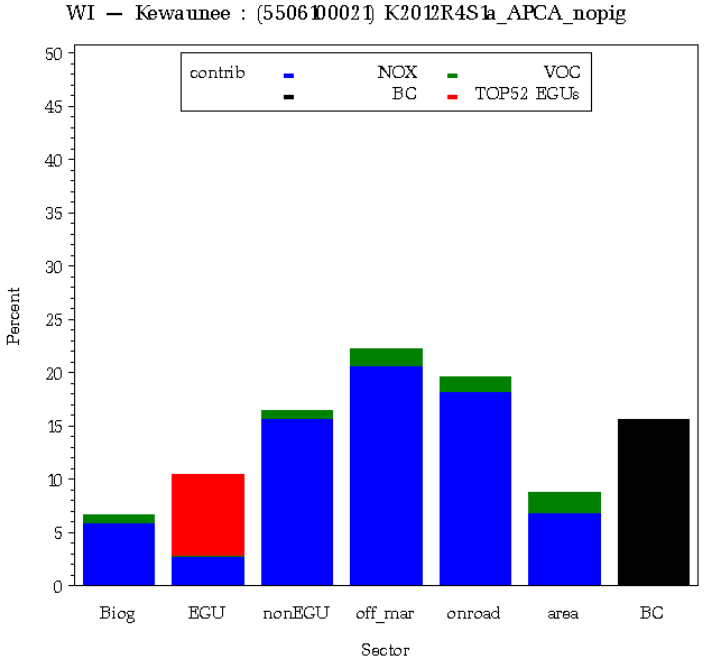

WI — Manitowoc : (550710071) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

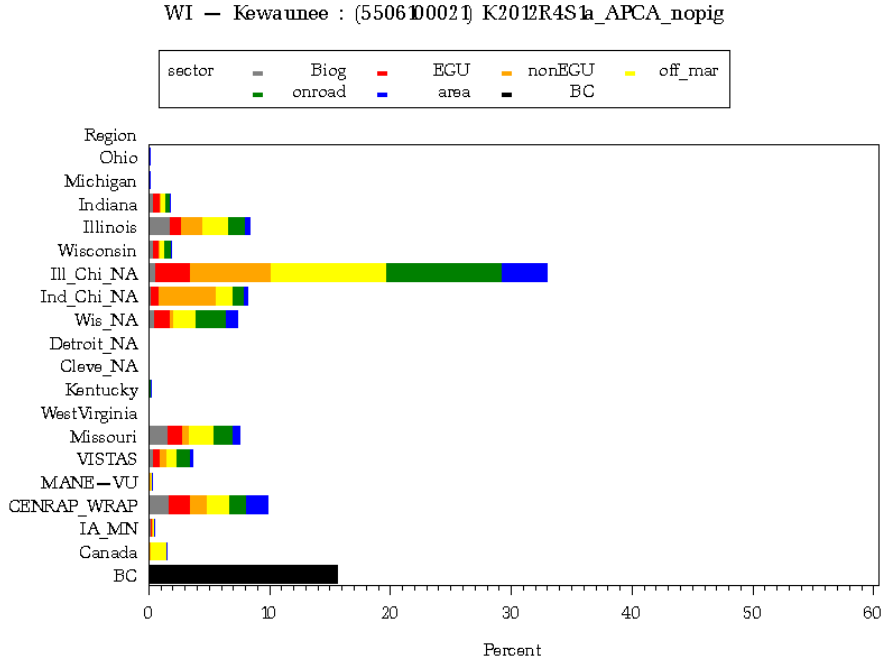

WI — Manitowoc : (550710071) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

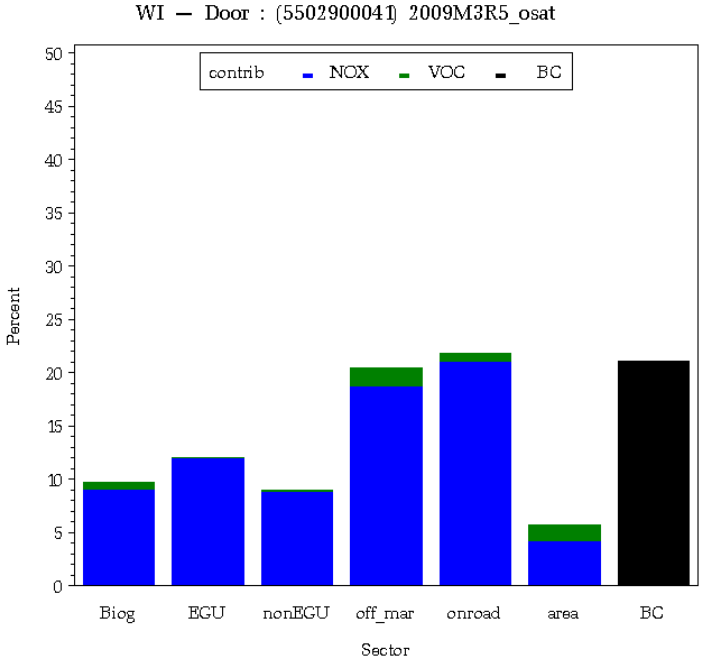

WI — Manitowoc : (550710071) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

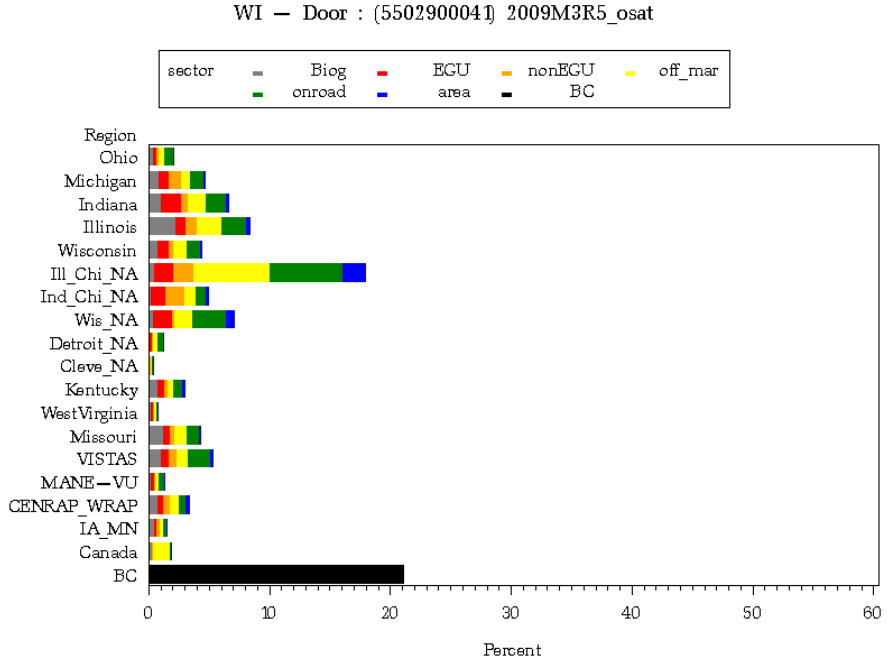

WI — Kewaunee : (550610002 1) 2009M3R5_osat
contrib NOX VOC BC
Percent
0 5 10 15 20 25 30 35 40 45 50
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Kewaunee : (550610002 1) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0 10 20 30 40 50 60
Percent


WI — Kewaunee : (550610002 1) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
0 5 10 15 20 25 30 35 40 45 50
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Kewaunee : (550610002 1) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0 10 20 30 40 50 60
Percent


WI — Door : (550290041) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Door : (550290041) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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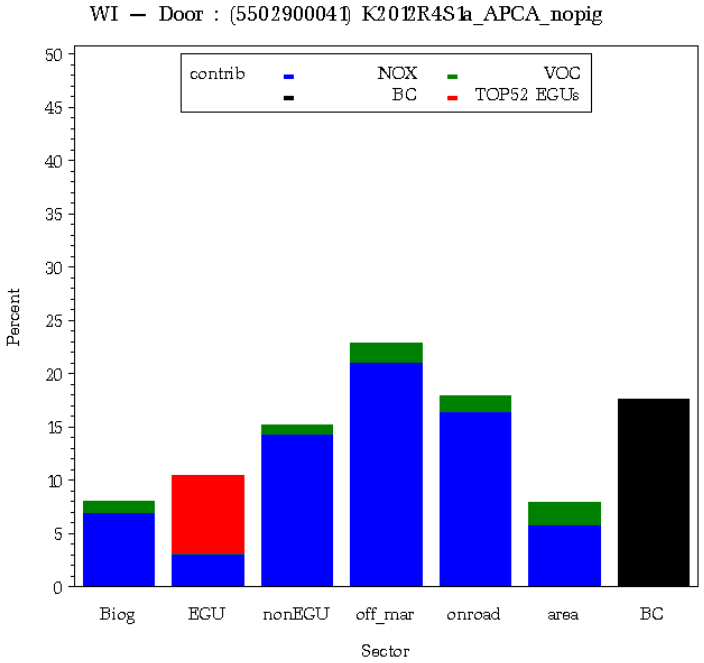
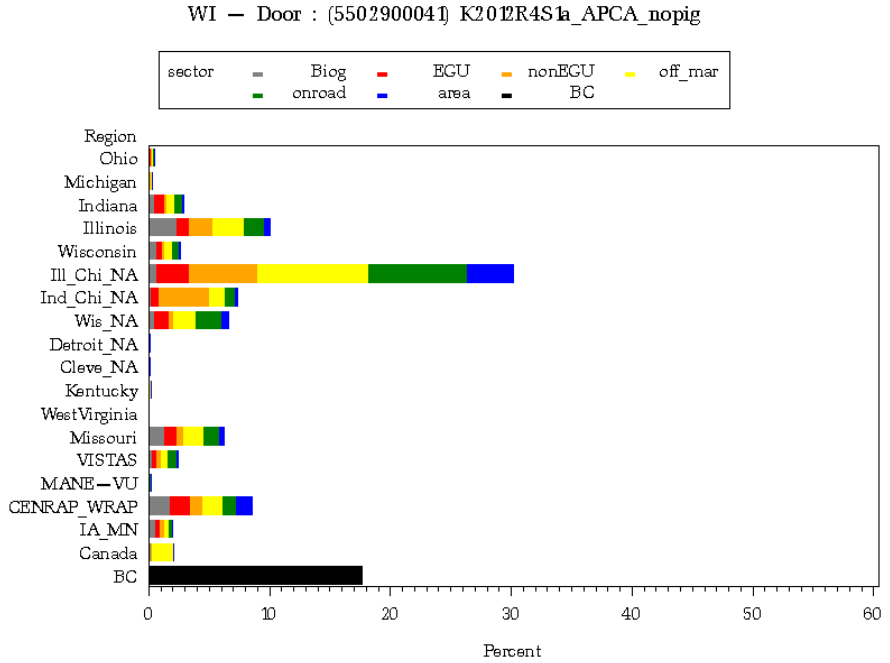
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Door : (550290041) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Door : (550290041) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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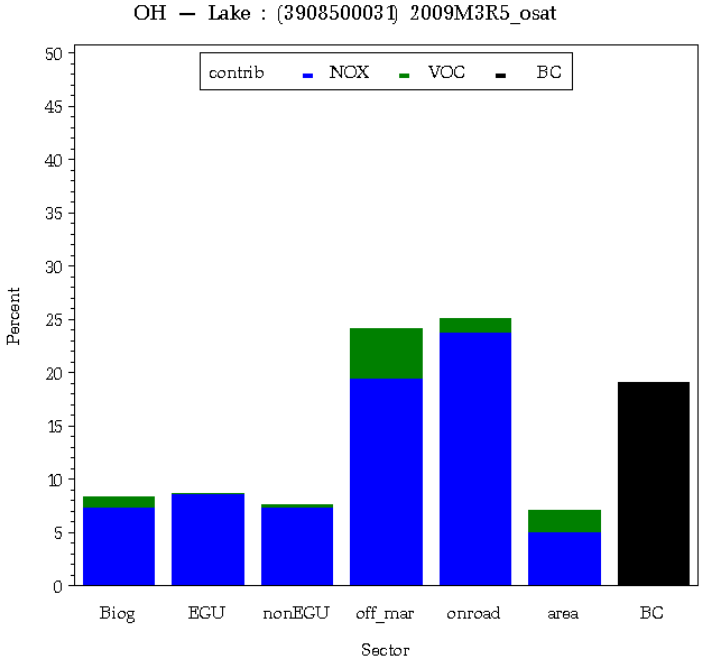
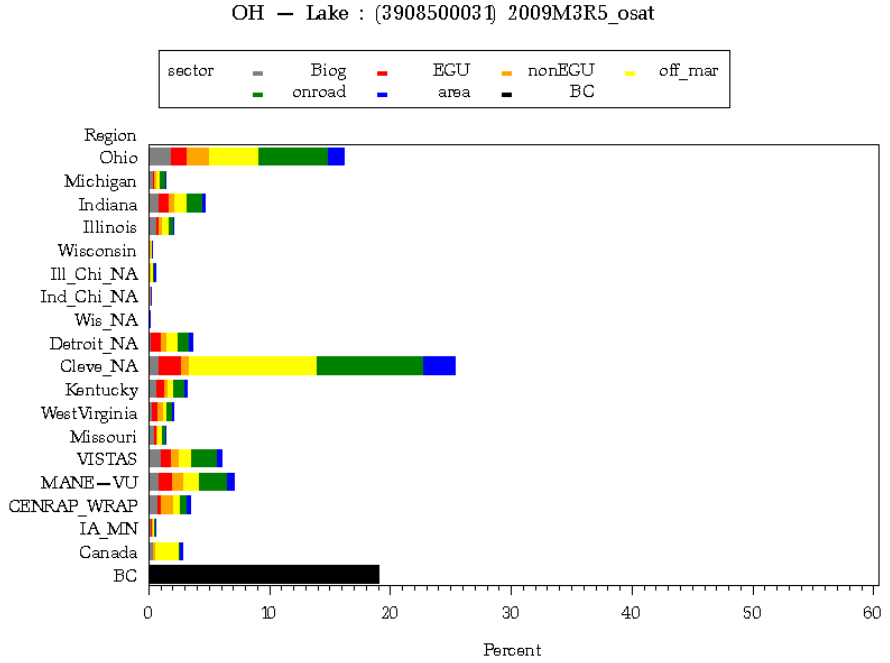
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Lake : (390850003) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


OH — Lake : (390850003) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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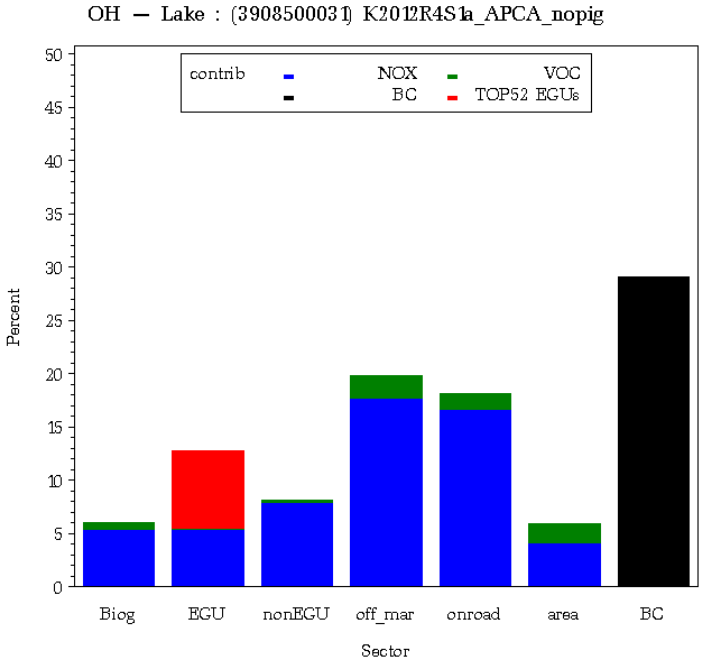
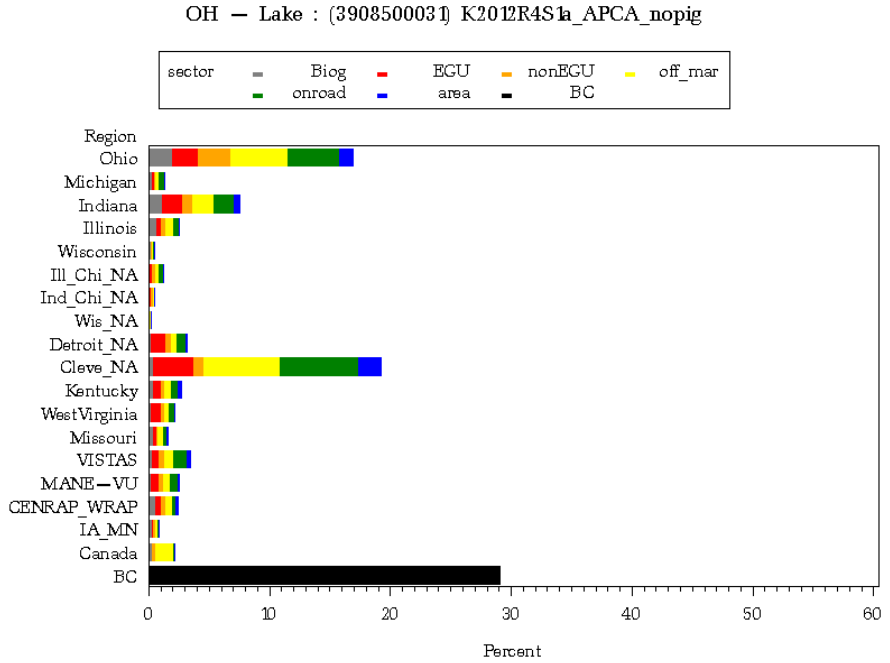
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Lake : (390850003) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


OH — Lake : (390850003) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
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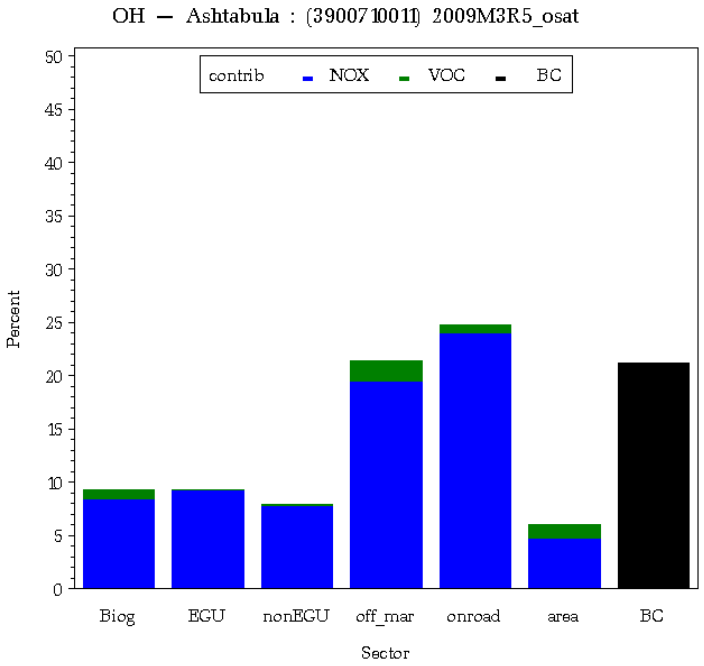
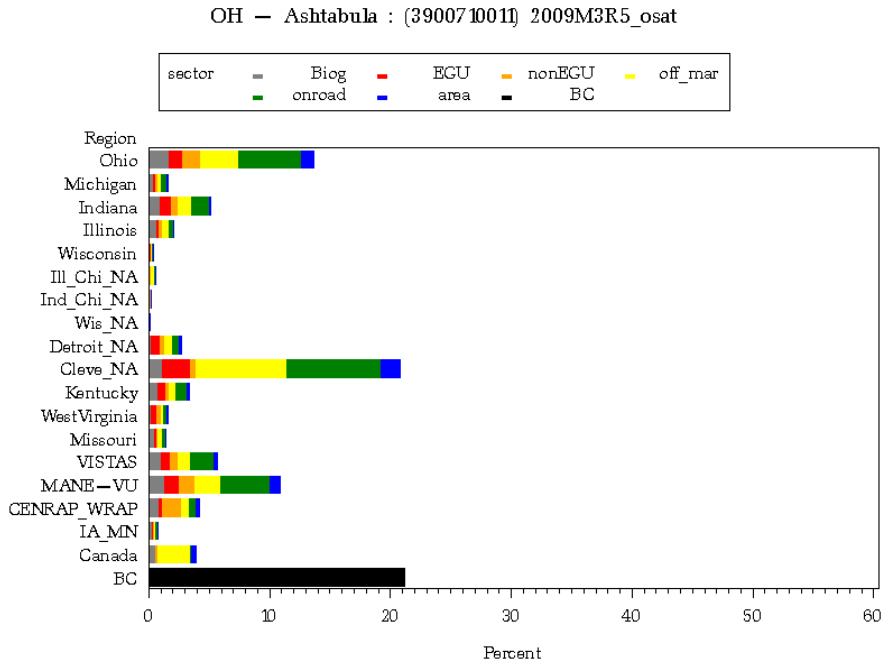
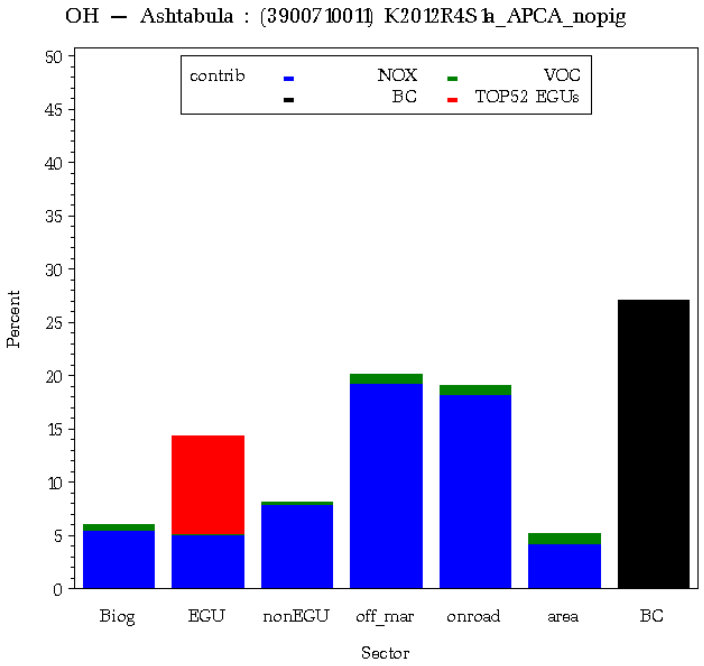
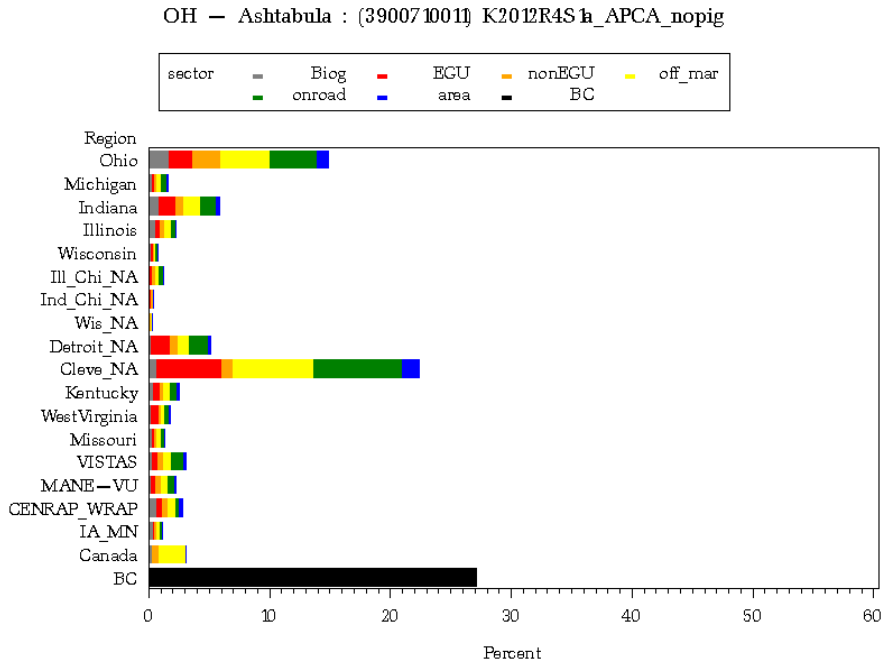
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Ashtabula : (390071001) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Ashtabula : (390071001) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Ashtabula : (390071001) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Ashtabula : (390071001) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
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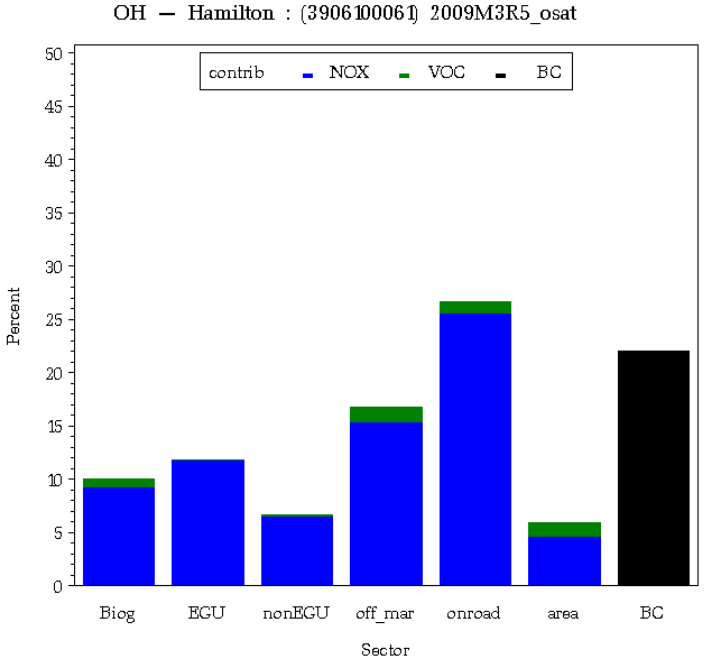
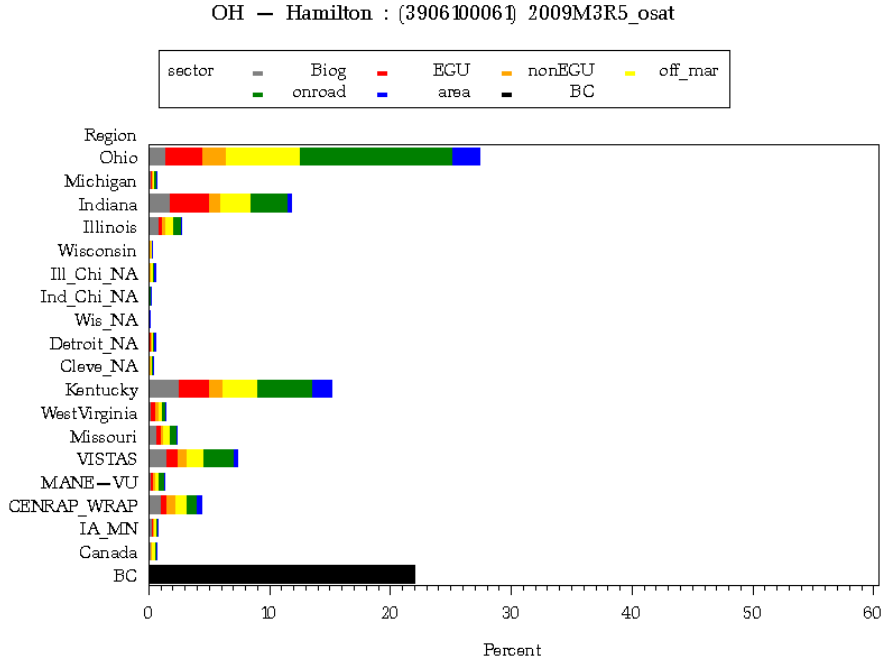
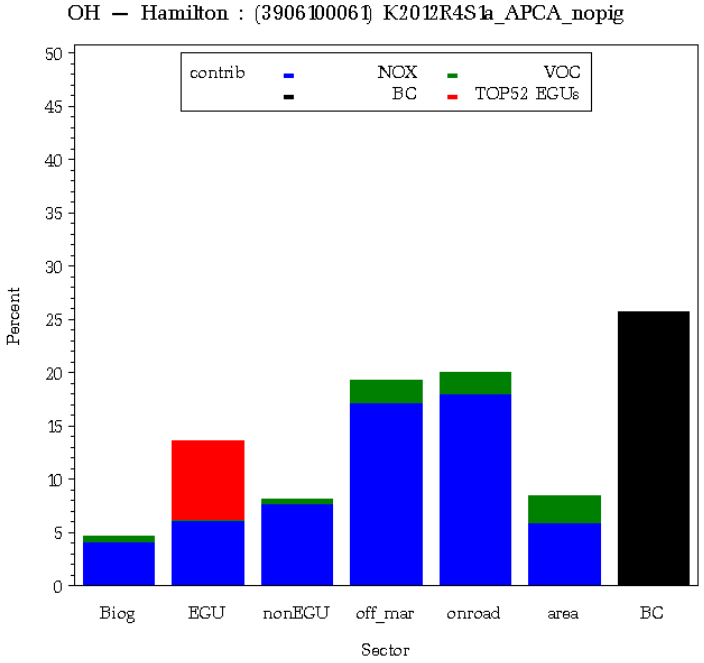
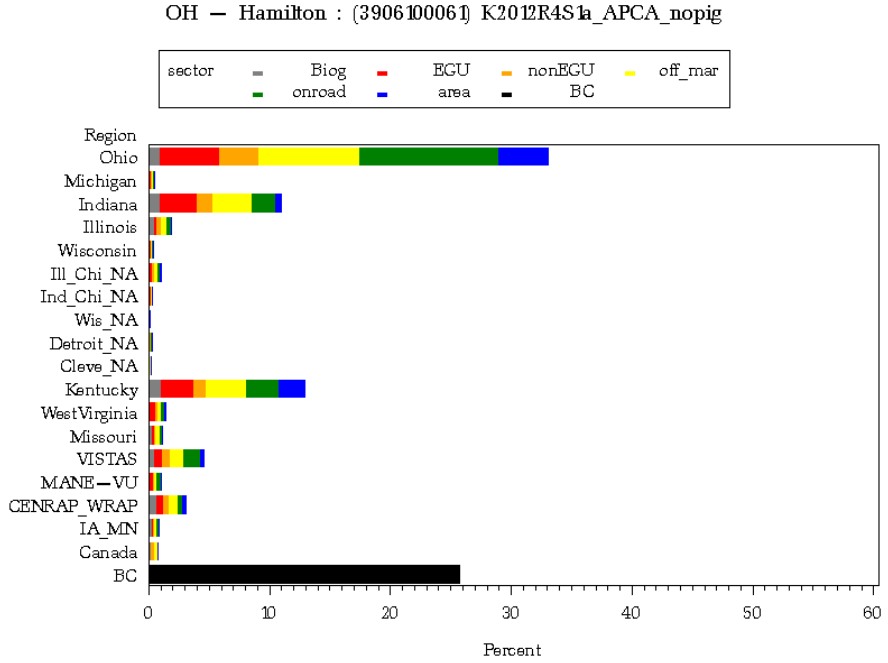
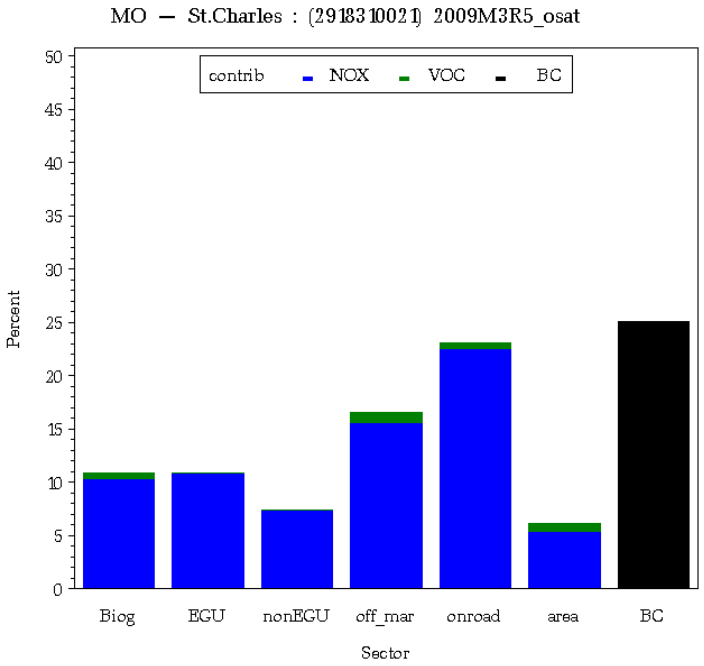
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

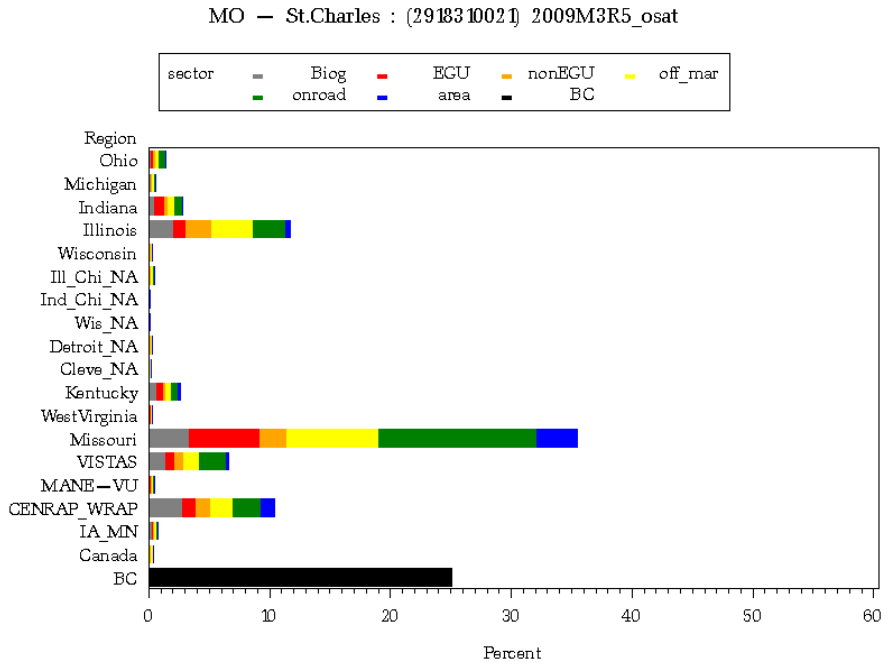

OH — Hamilton : (3906100061) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

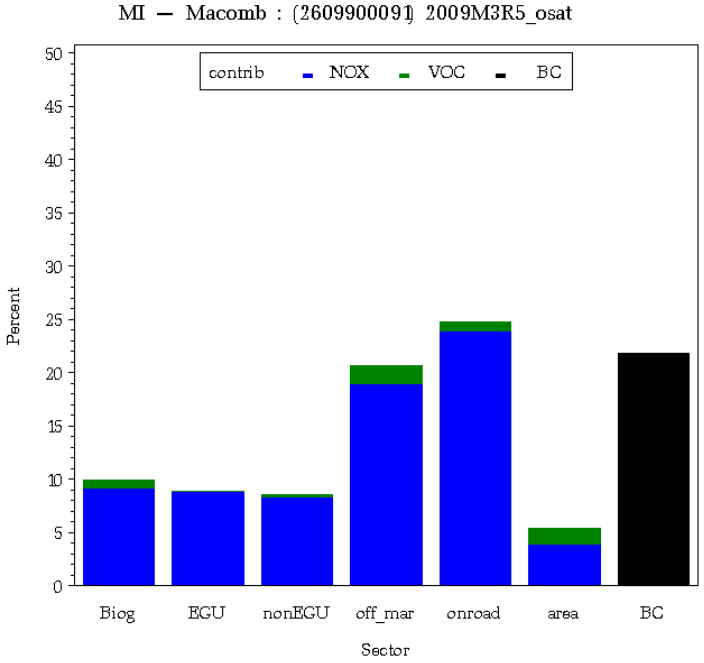

OH — Hamilton : (3906100061) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

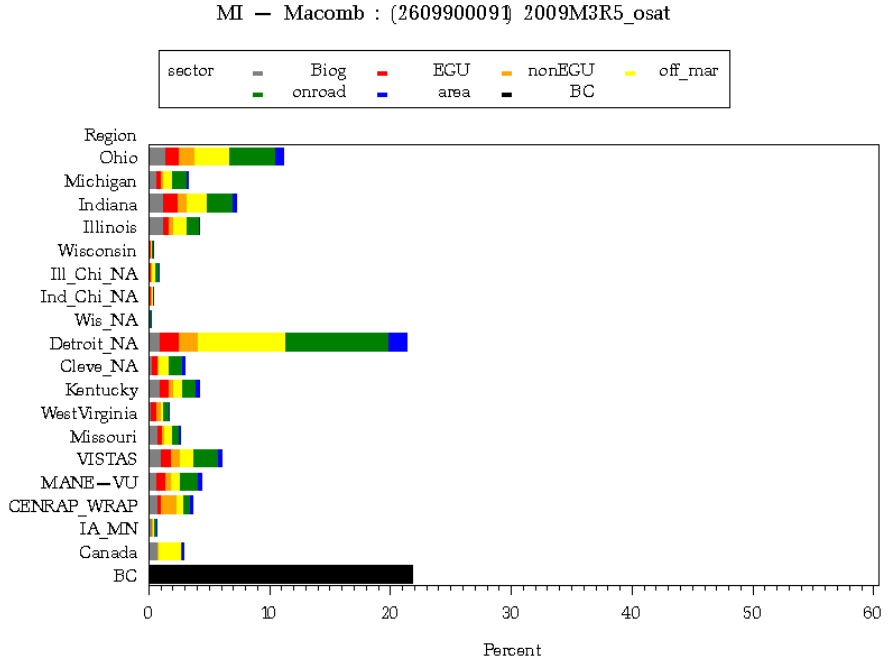

OH — Hamilton : (3906100061) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

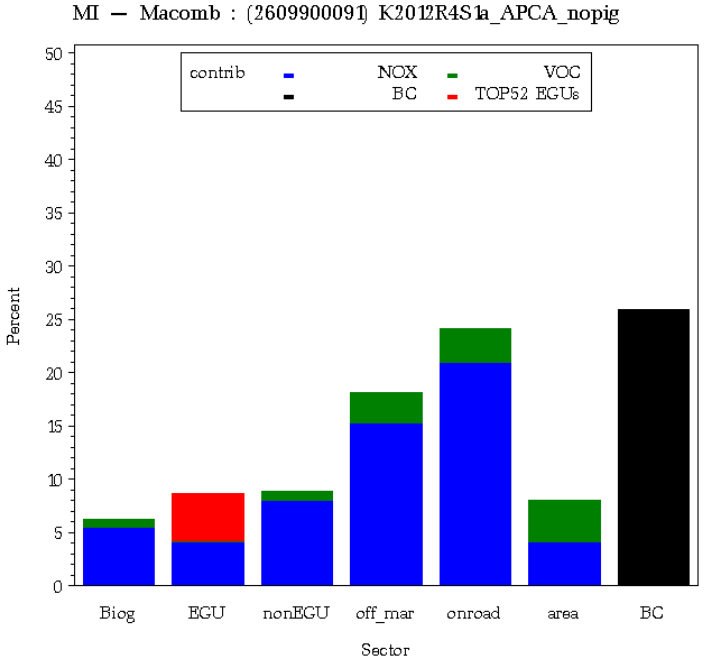

OH — Hamilton : (3906100061) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


MO — St.Charles : (291831002 1) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
0
5
10
15
20
25
30
35
40
45
50
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


MO — St.Charles : (291831002 1) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0
10
20
30
40
50
60
Percent


MI — Macomb : (2609900091) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Macomb : (2609900091) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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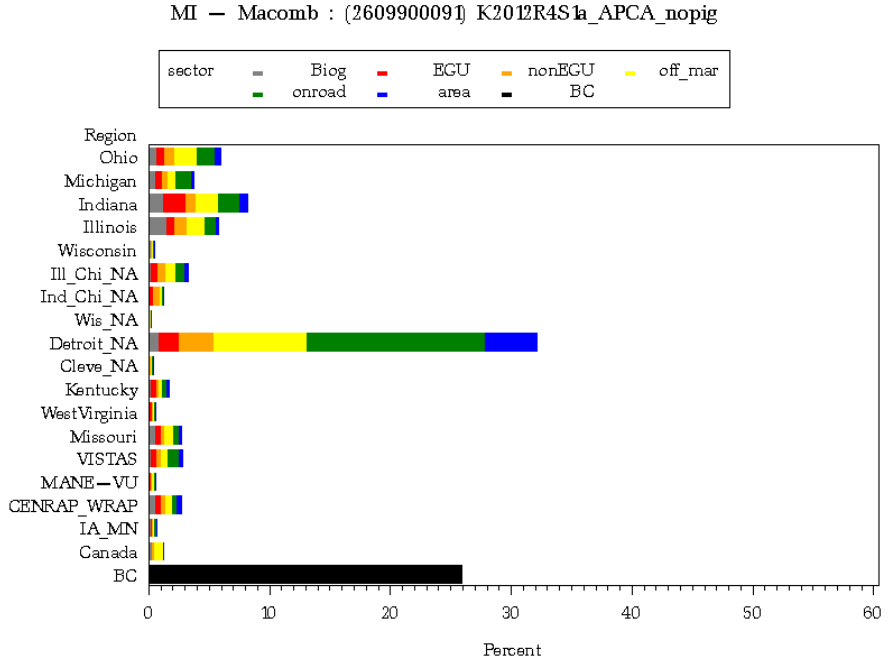
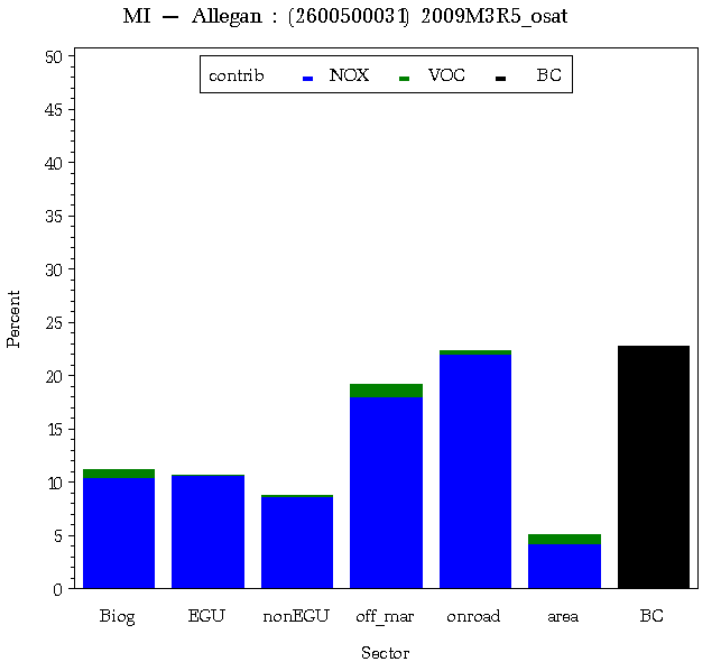
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Macomb : (2609900091) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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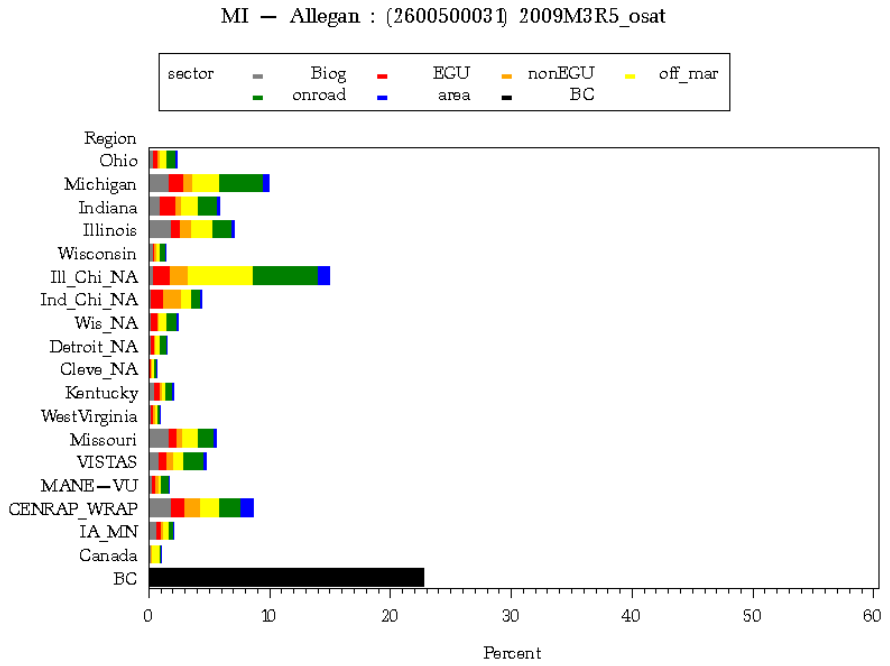
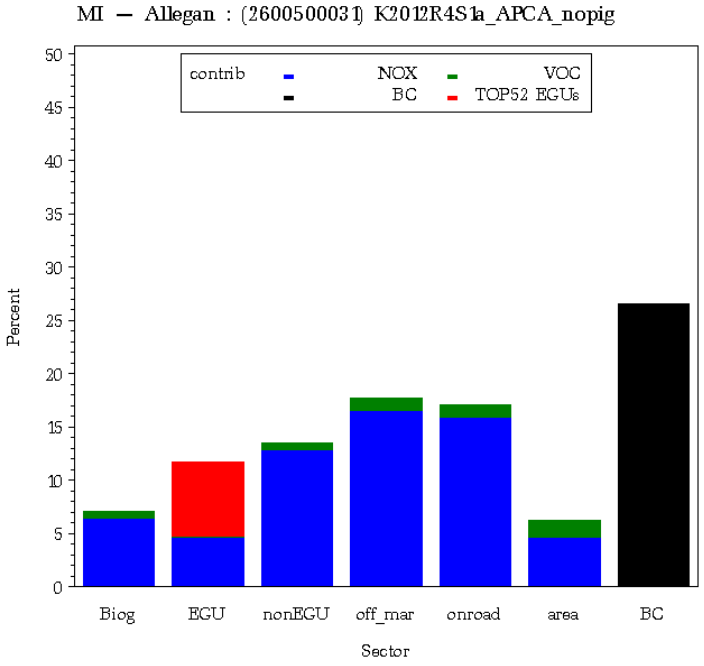
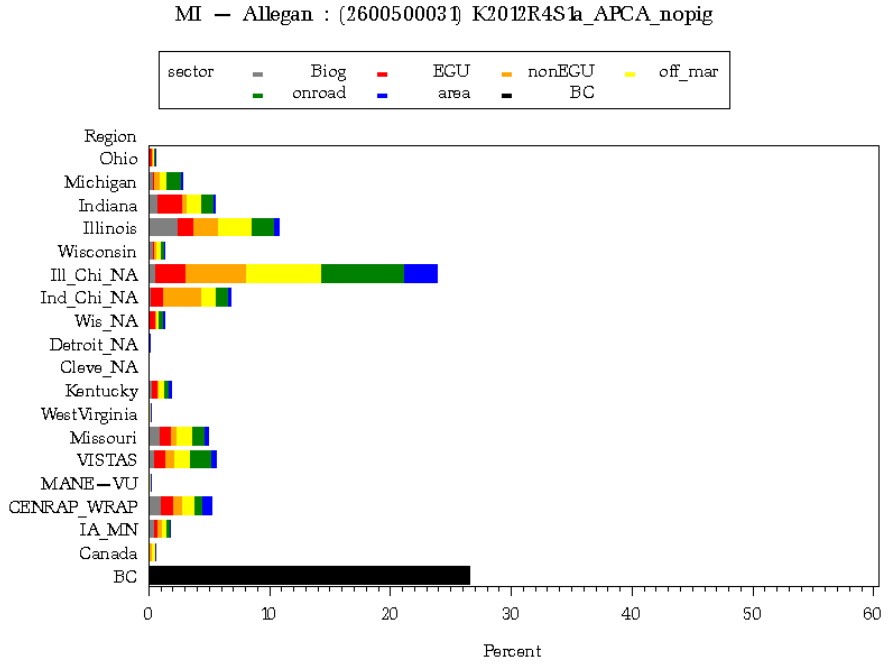
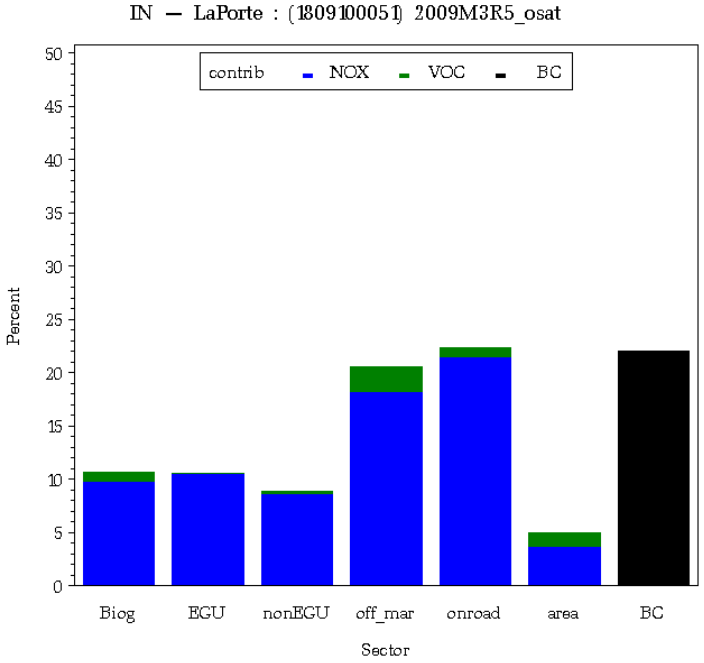
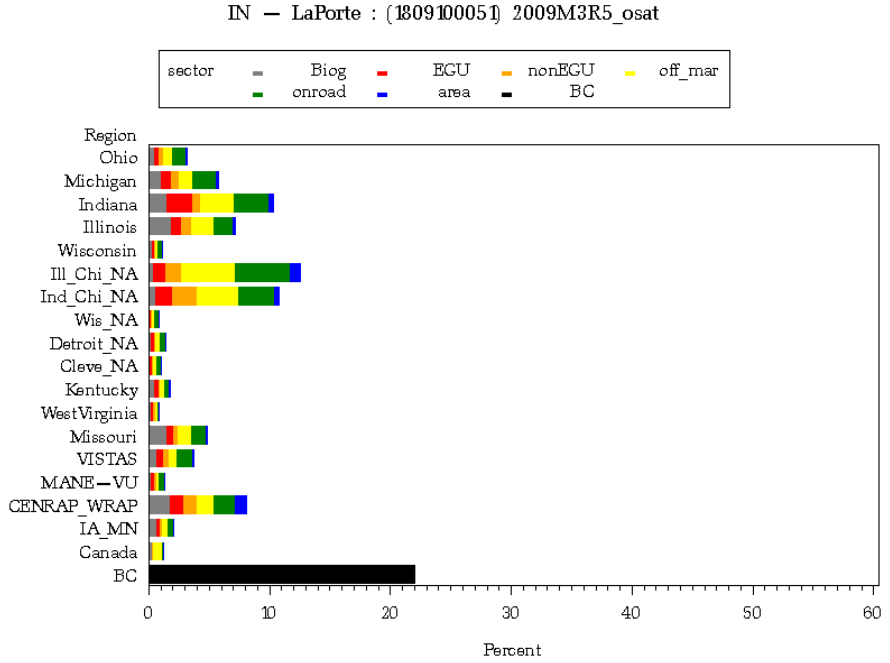
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Allegan : (2600500031) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


MI — Allegan : (2600500031) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Allegan : (2600500031) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — LaPorte : (180910005 1) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — LaPorte : (180910005 1) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
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WestVirginia
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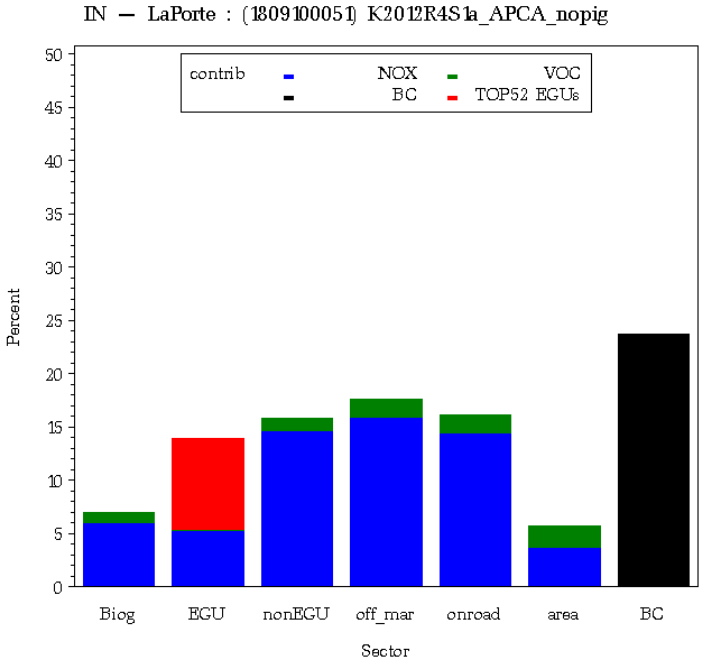
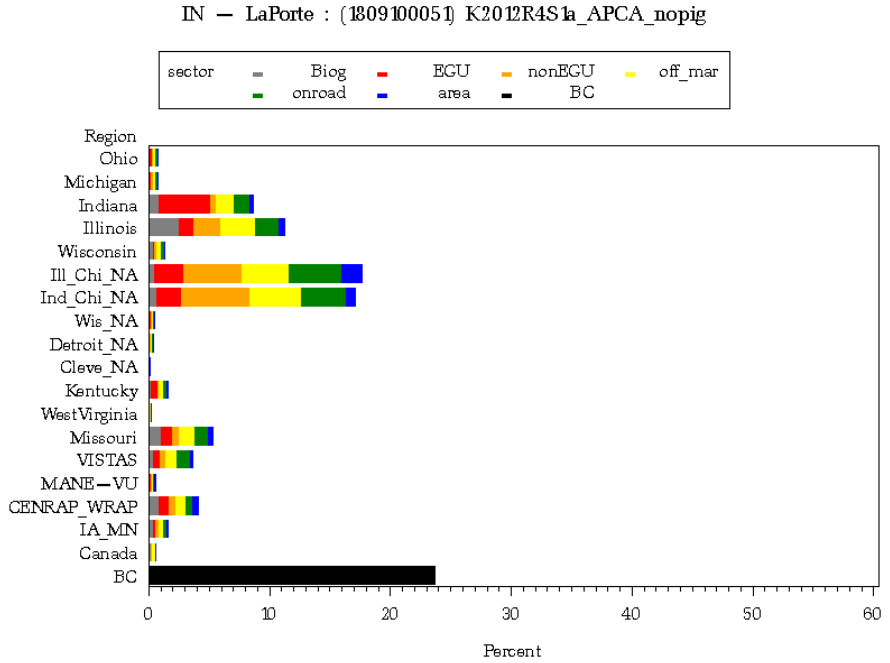
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — LaPorte : (180910005 1) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — LaPorte : (180910005 1) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
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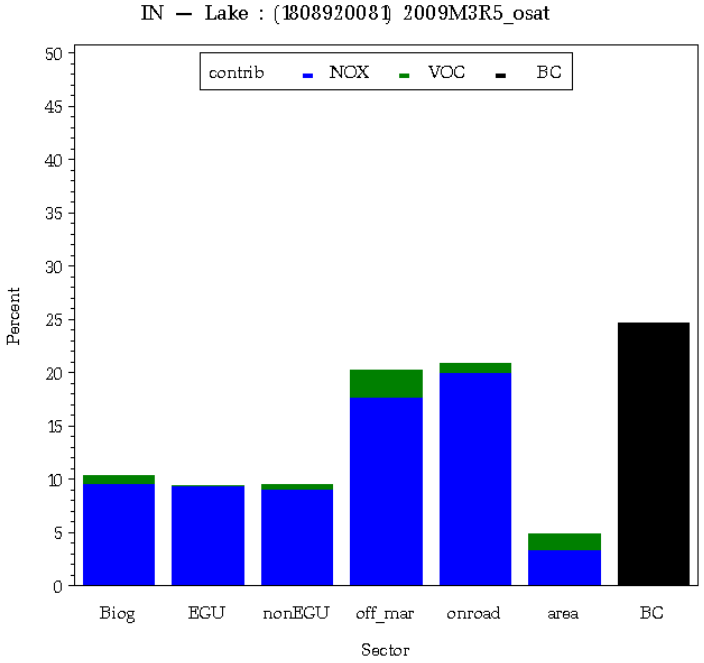
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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contrib
NOX
VOC
BC
Percent
0
5
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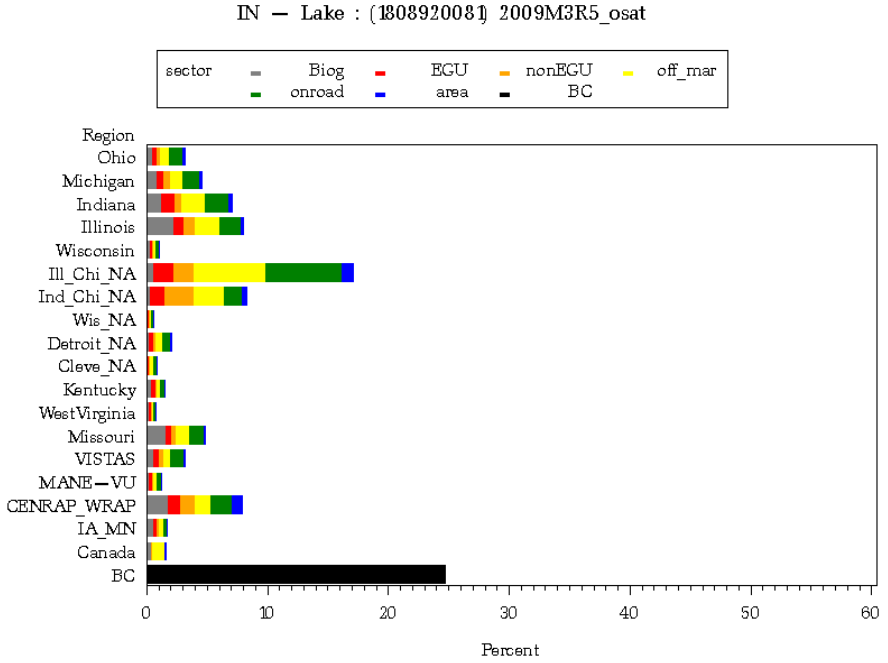
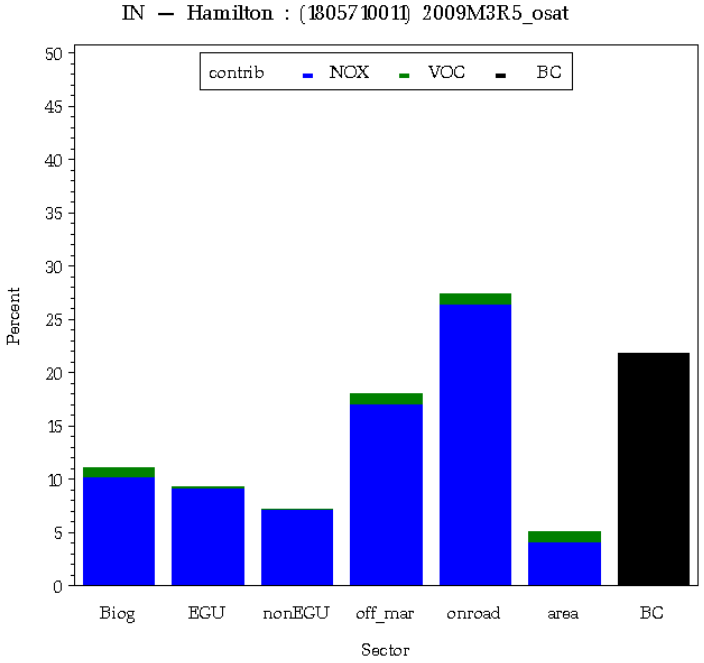
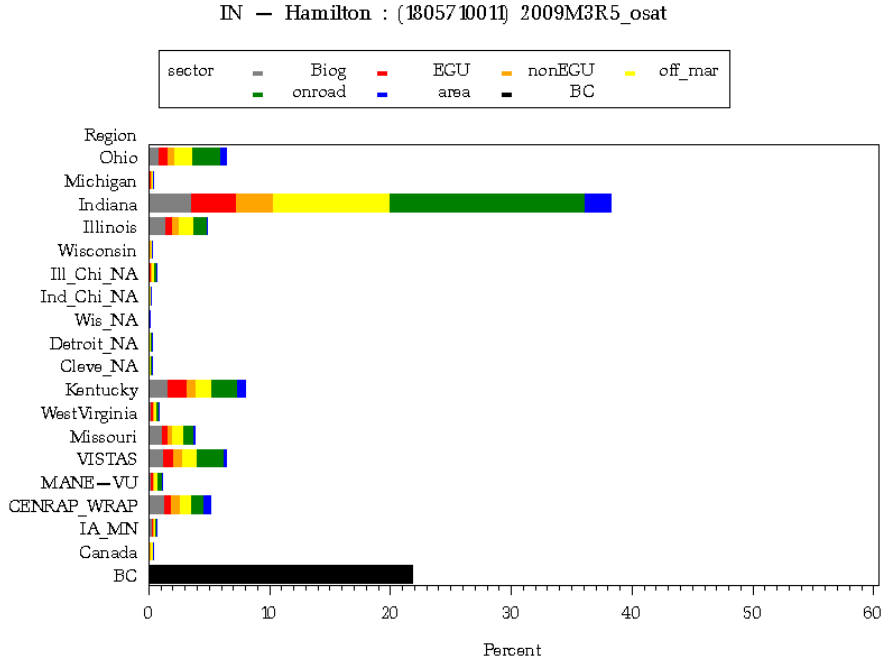
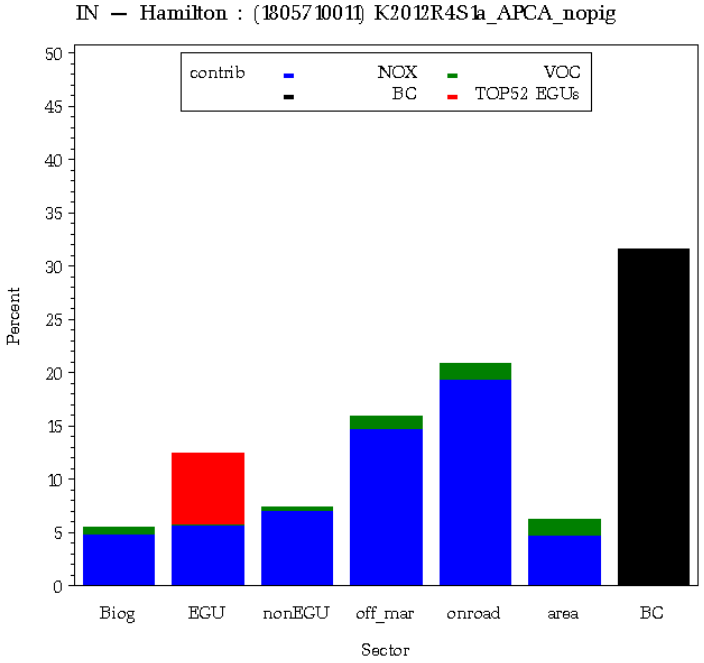
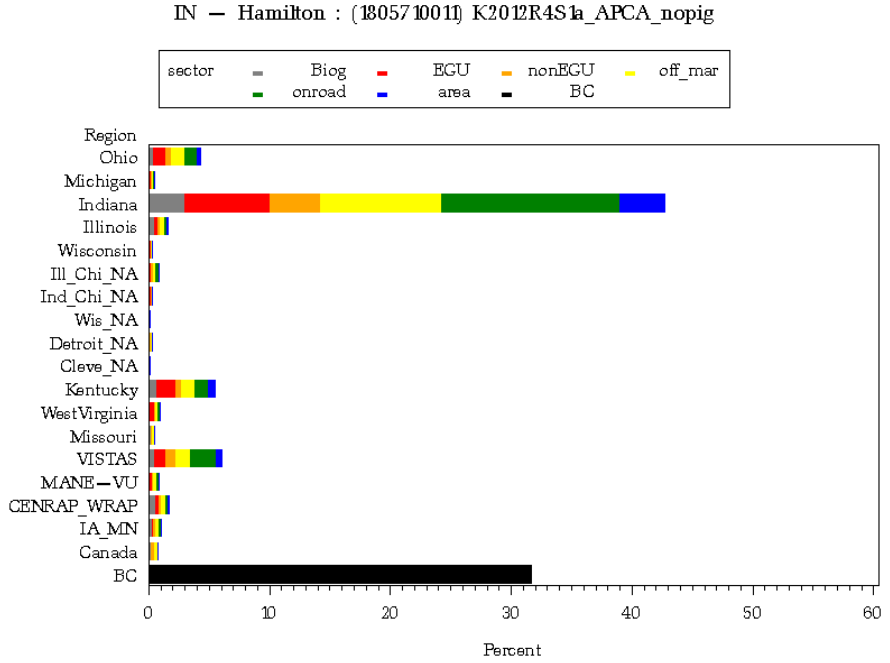
25
30
35
40
45
50
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — Lake : (1808920081) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0
10
20
30
40
50
60
Percent


IN — Hamilton : (180571011) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — Hamilton : (180571011) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — Hamilton : (180571011) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector

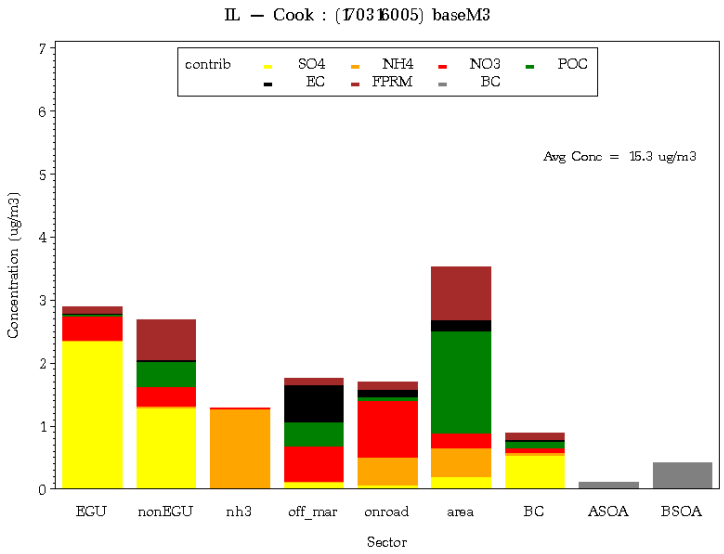

IN — Hamilton : (180571011) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

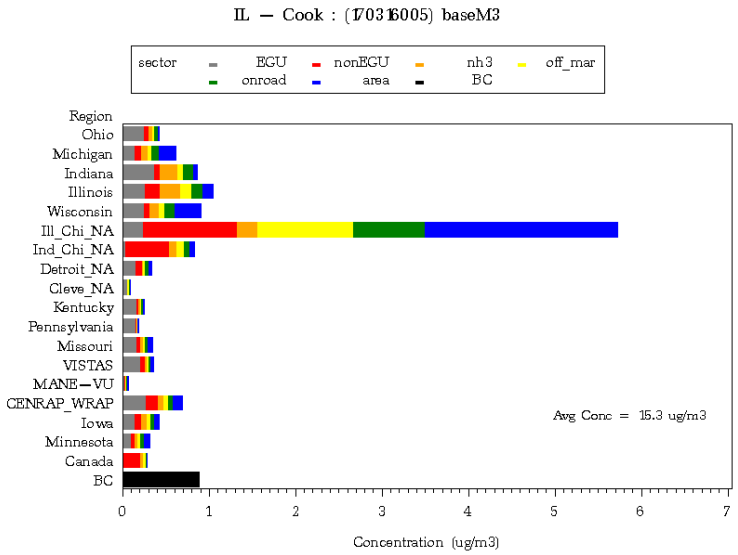
APPENDIX III

$PM_{2.5}$ Source Apportionment Modeling Results

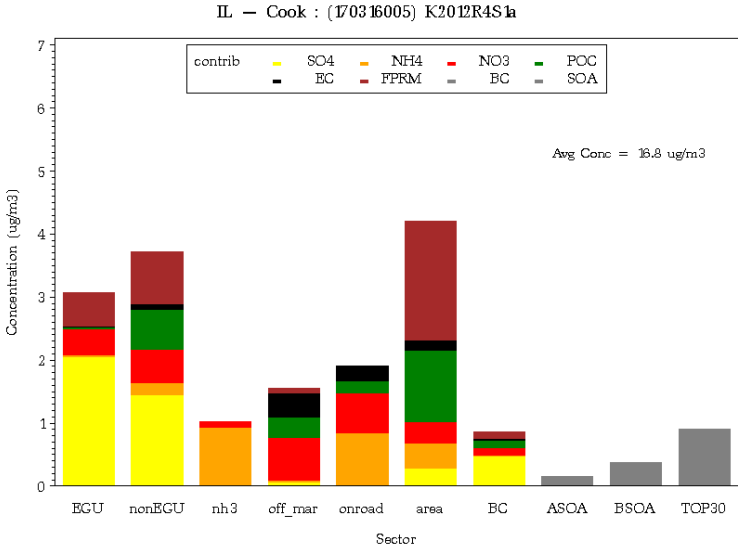
Chicago (Cicero), Illinois

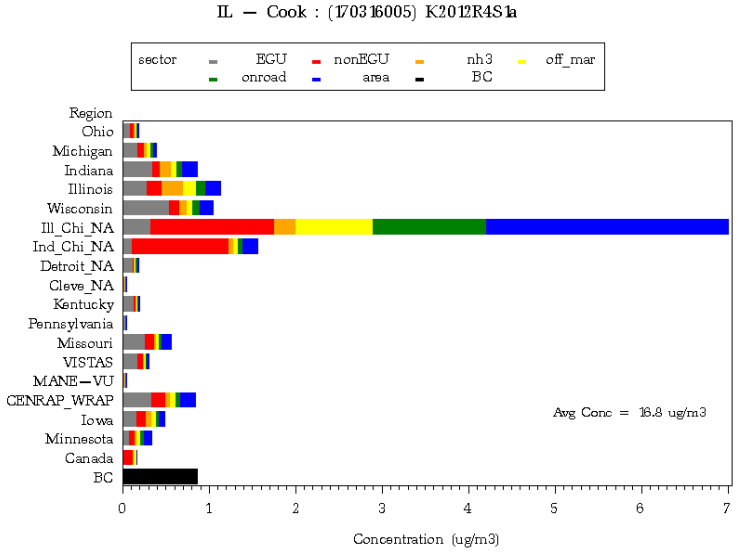
2005 (Round 5)



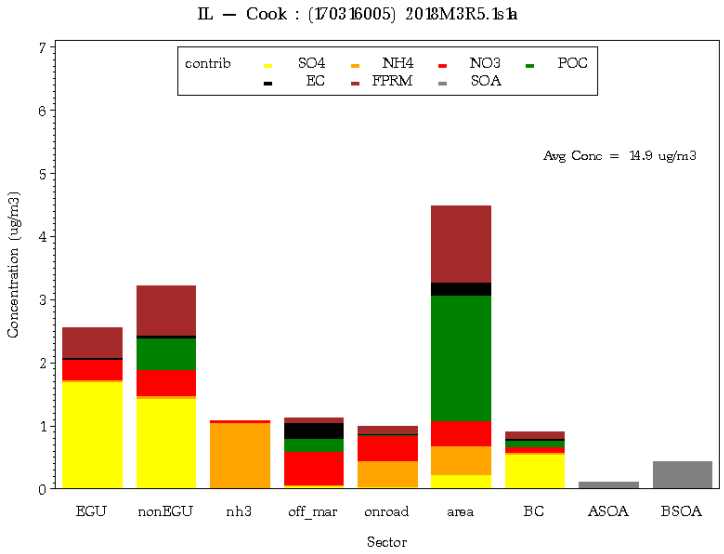


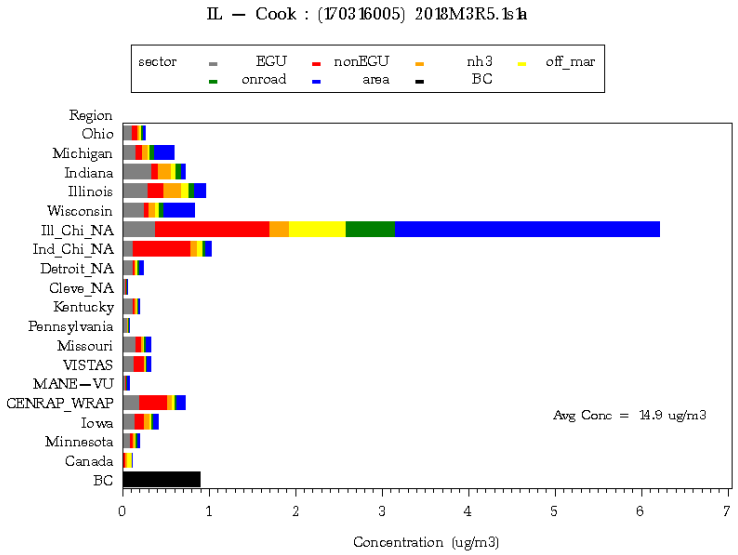
2012 (Round 4)





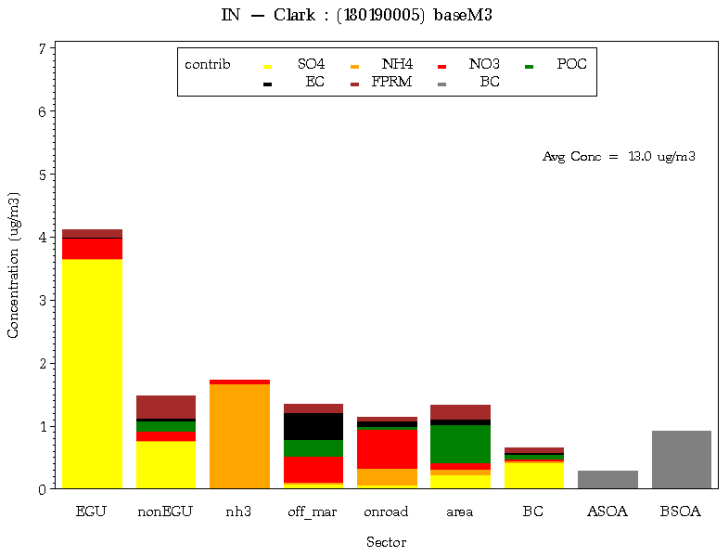
2018 (Round 5)

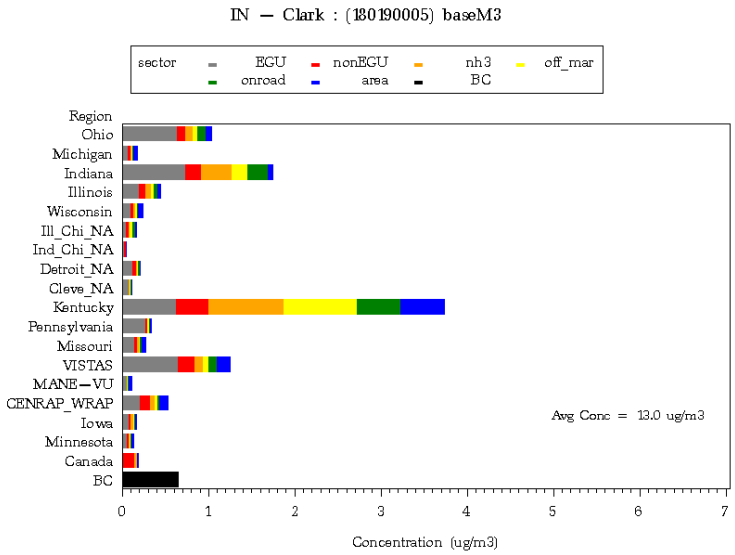




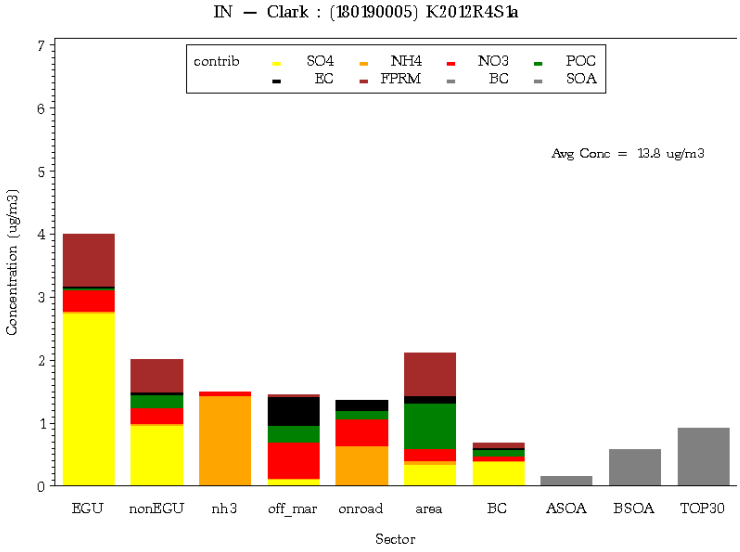
Clark County, Indiana

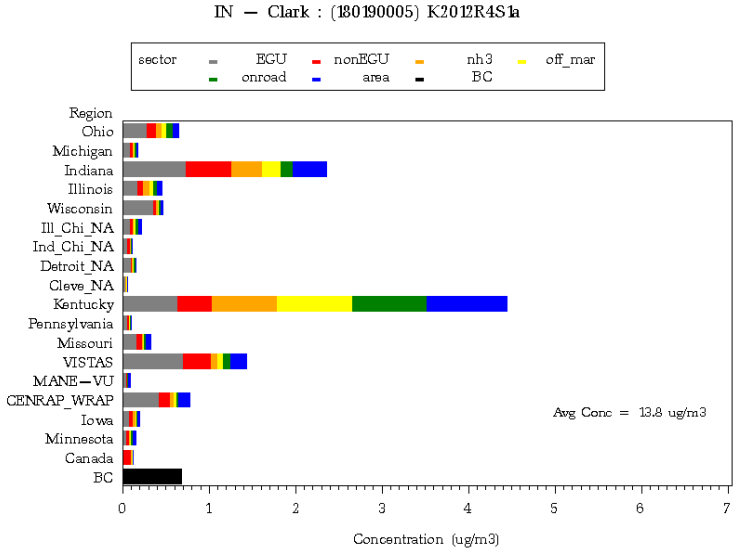
2005 (Round 5)



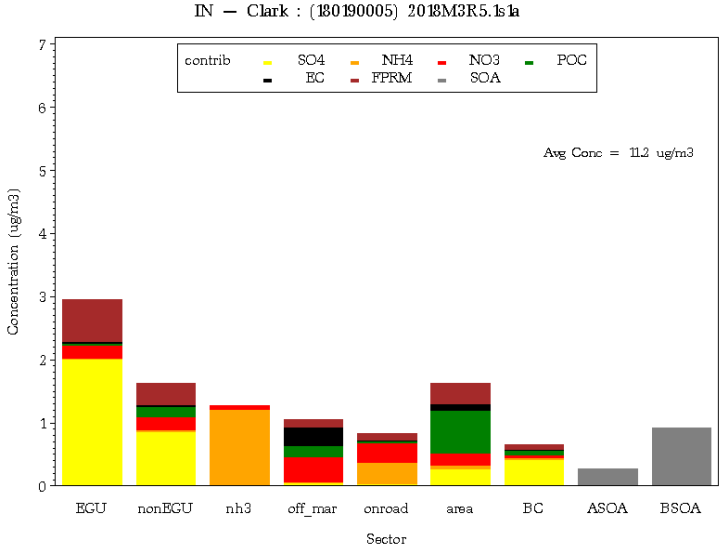


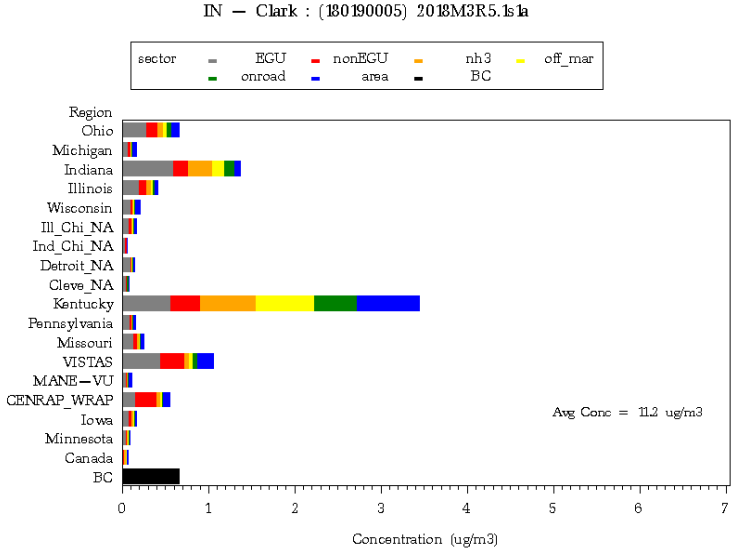
2012 (Round 4)





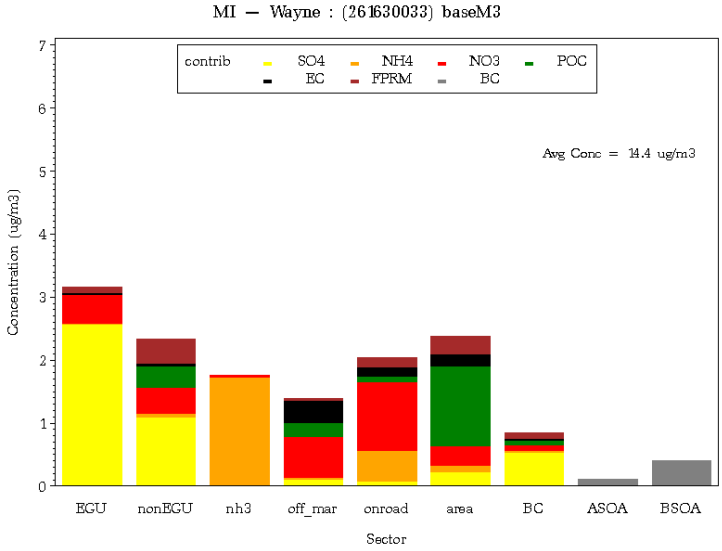
2018 (Round 5)

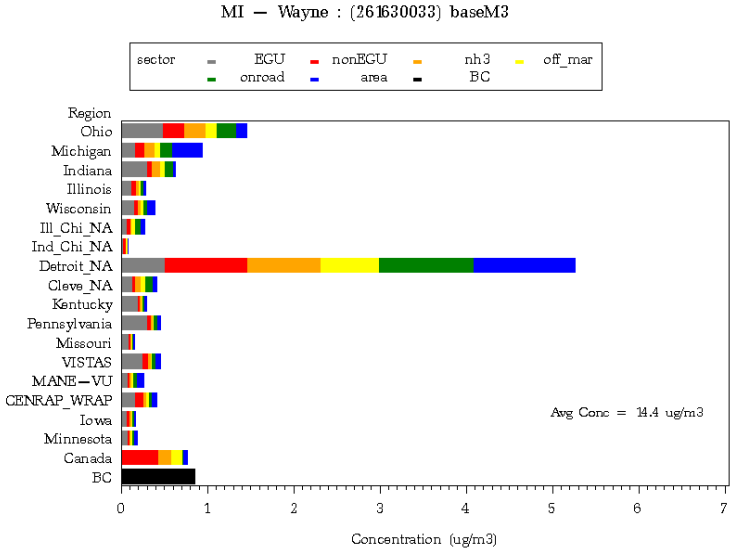




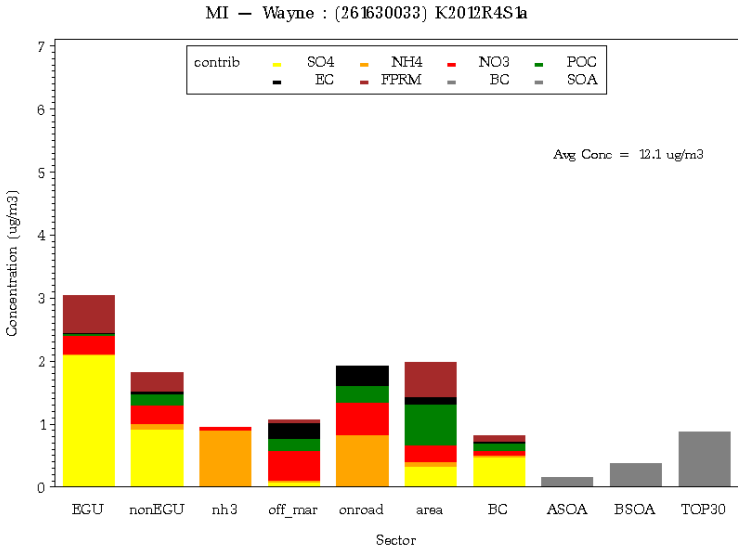
Dearborn, Michigan

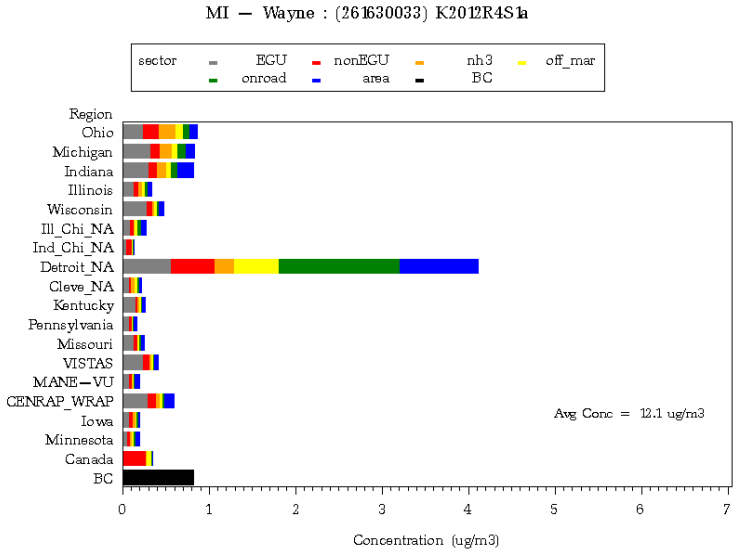
2005 (Round 5)



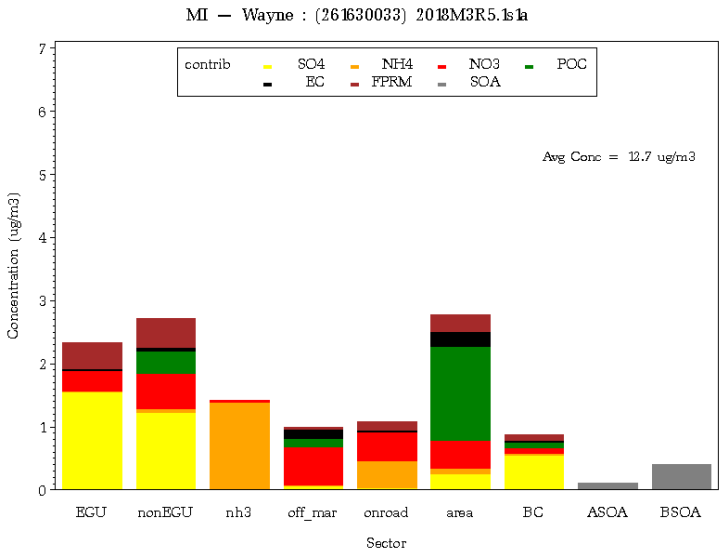


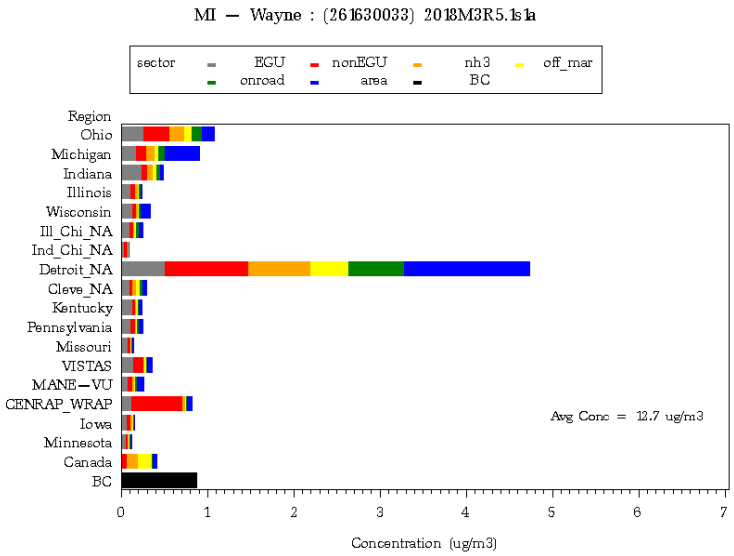
2012 (Round 4)





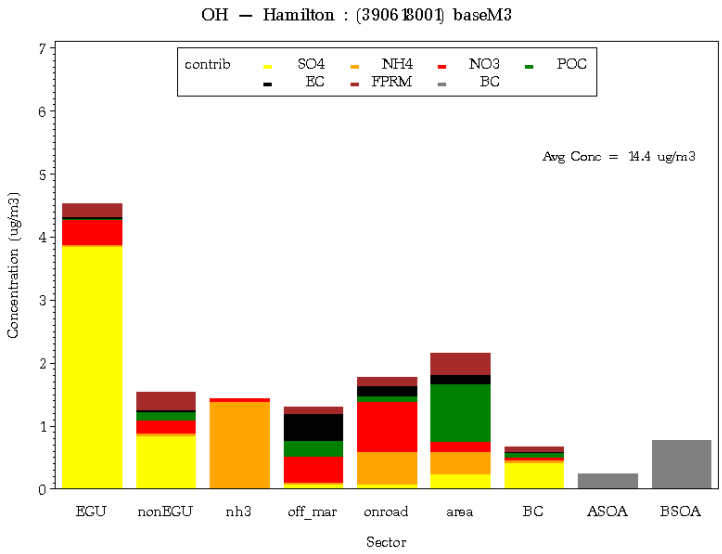
2018 (Round 5)

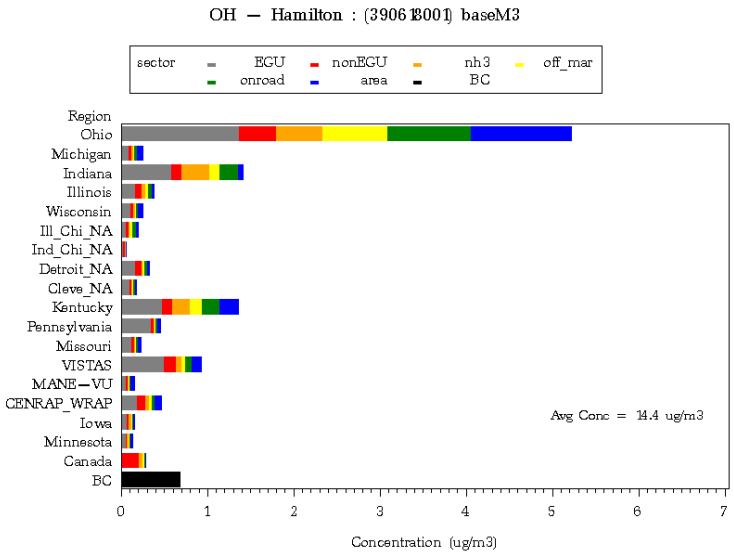




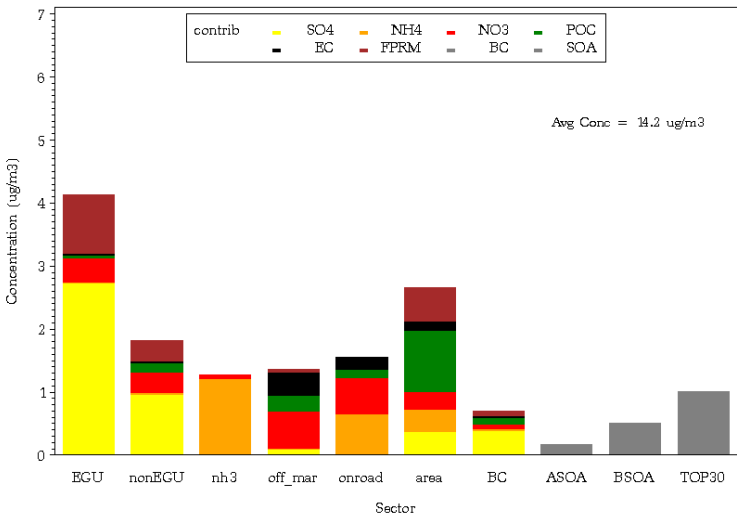
Cincinnati, Ohio

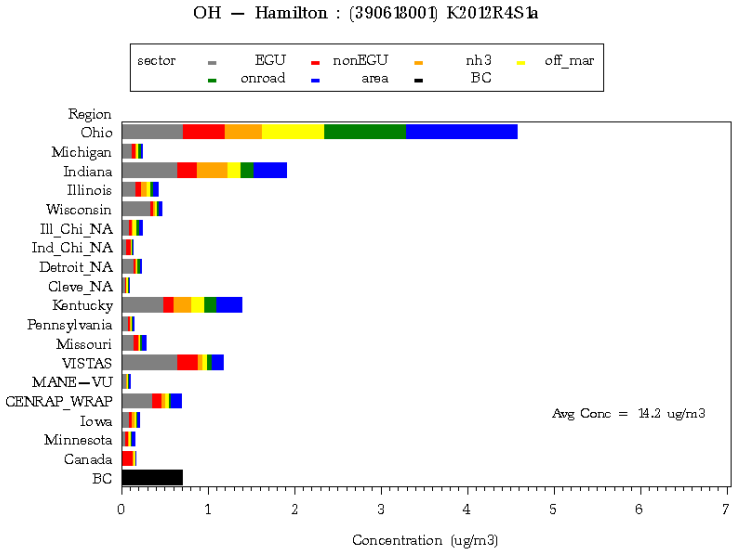
2005 (Round 5)



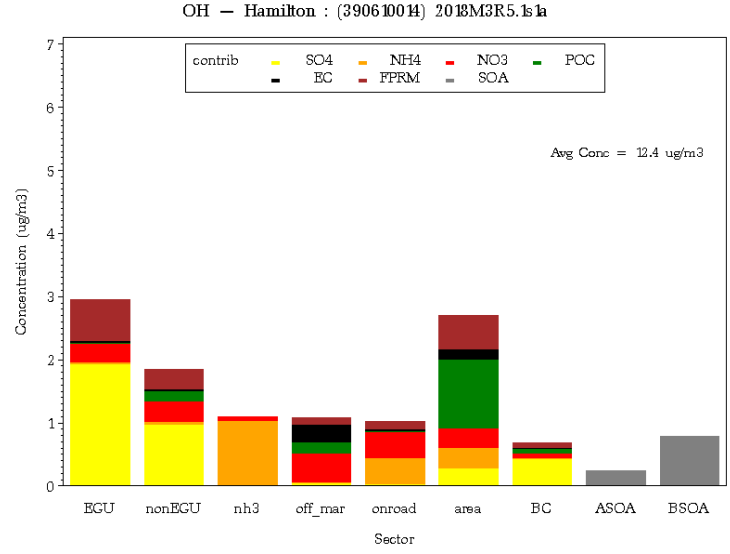


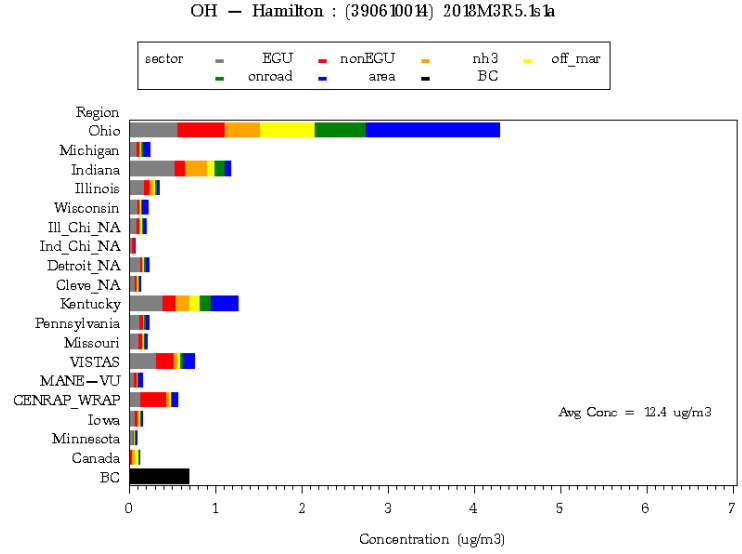
2012 (Round 4)





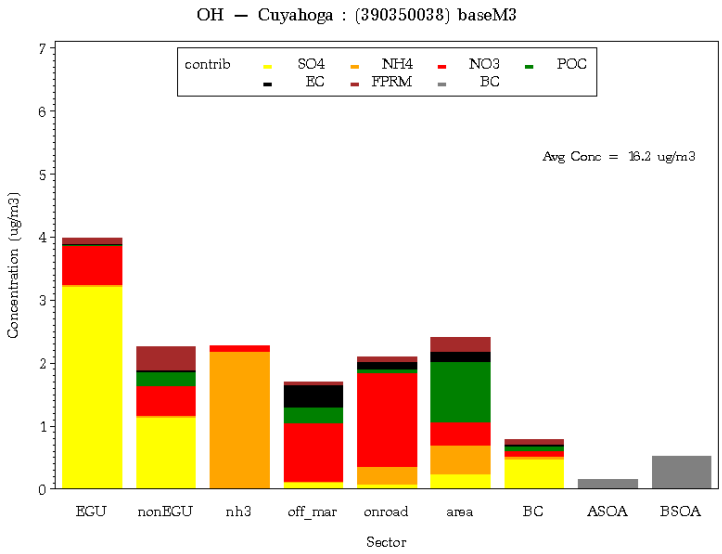
2018 (Round 5)

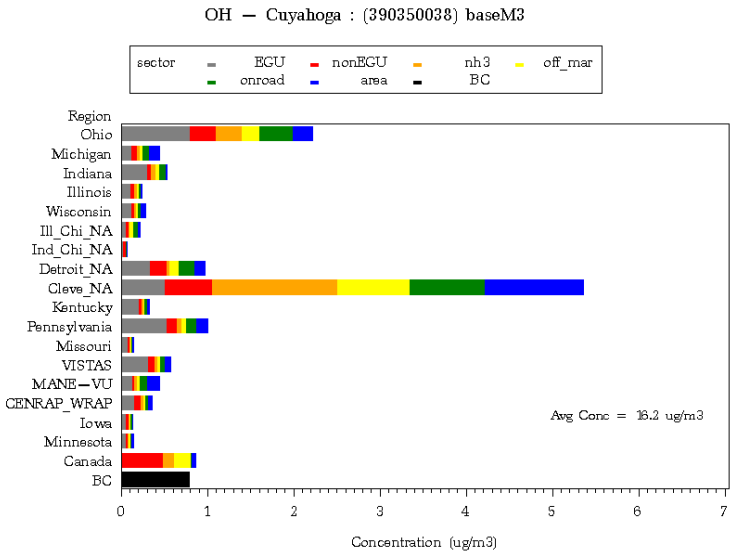




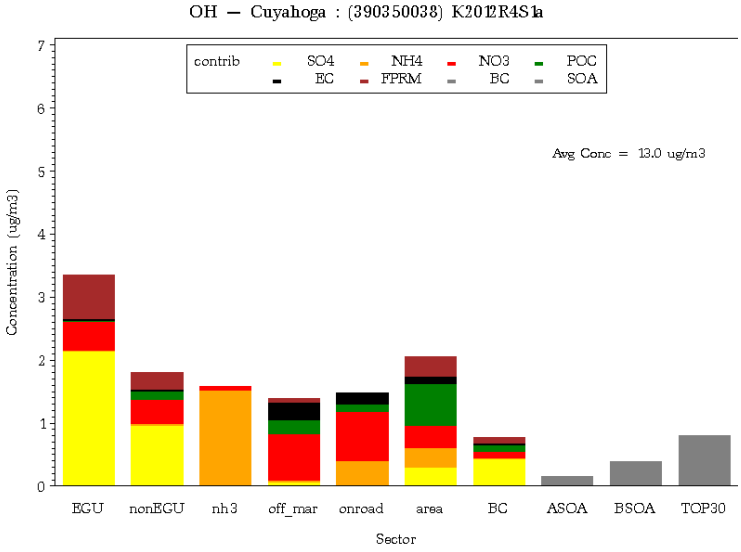
Cleveland, Ohio

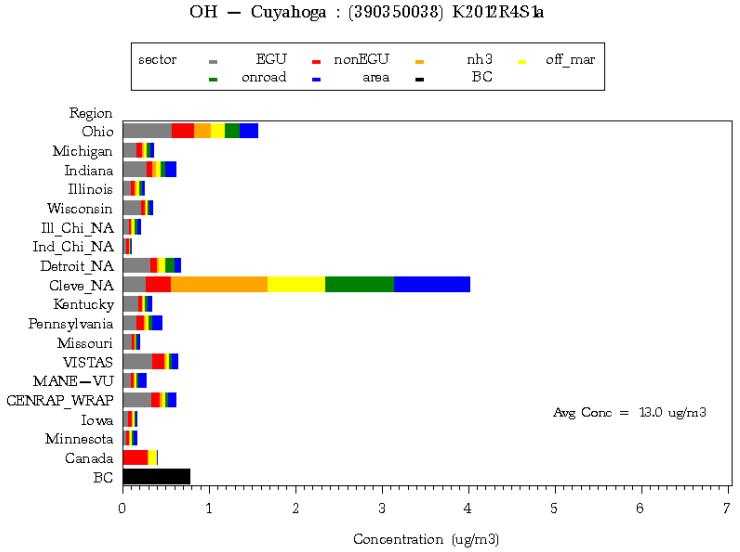
2005 (Round 5)



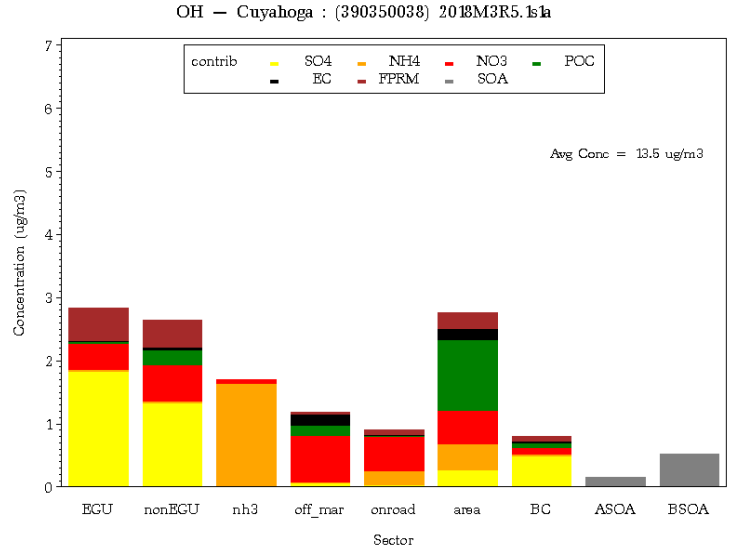


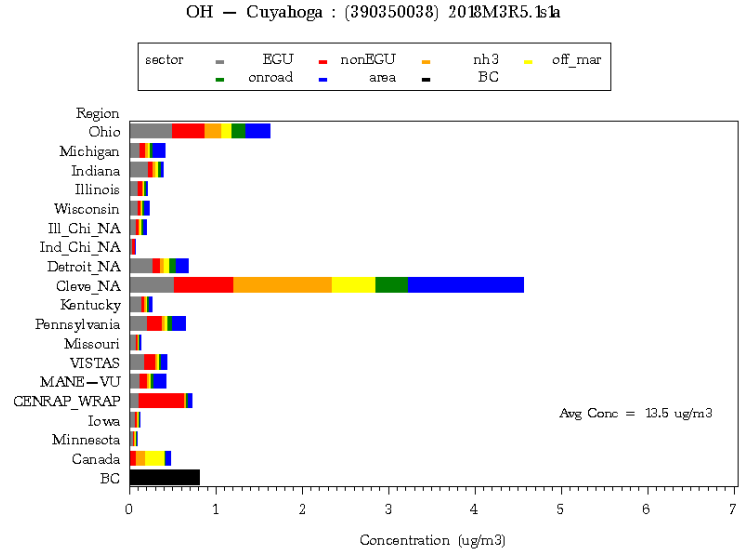
2012 (Round 4)





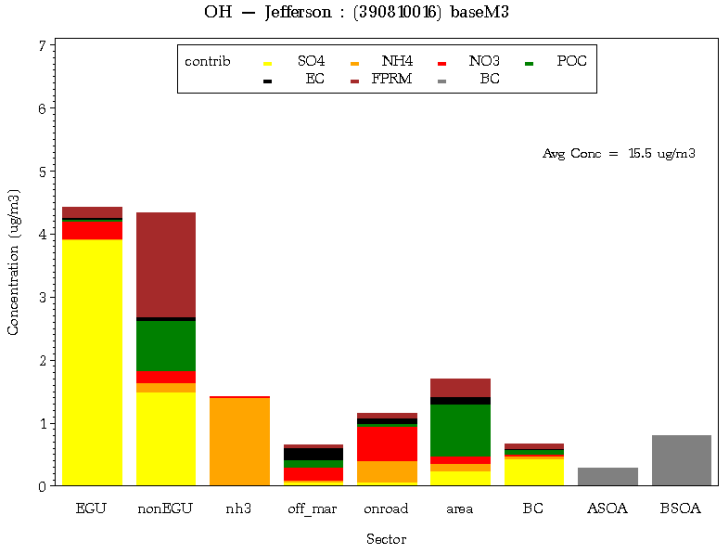
2018 (Round 5)

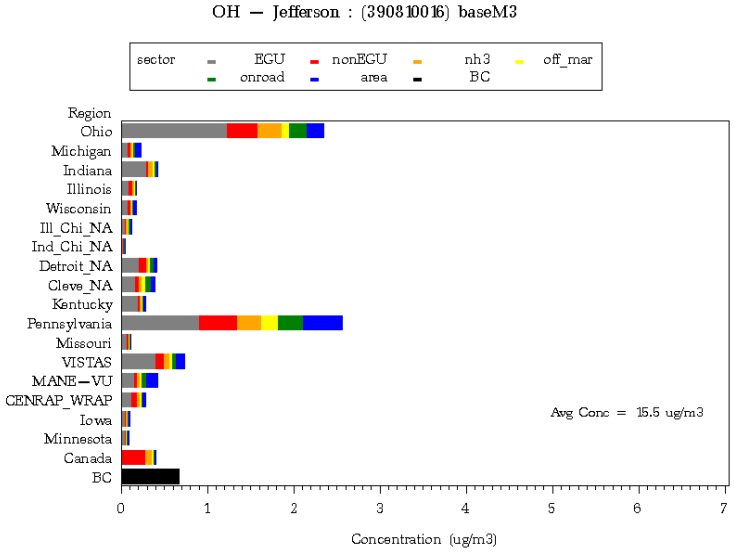




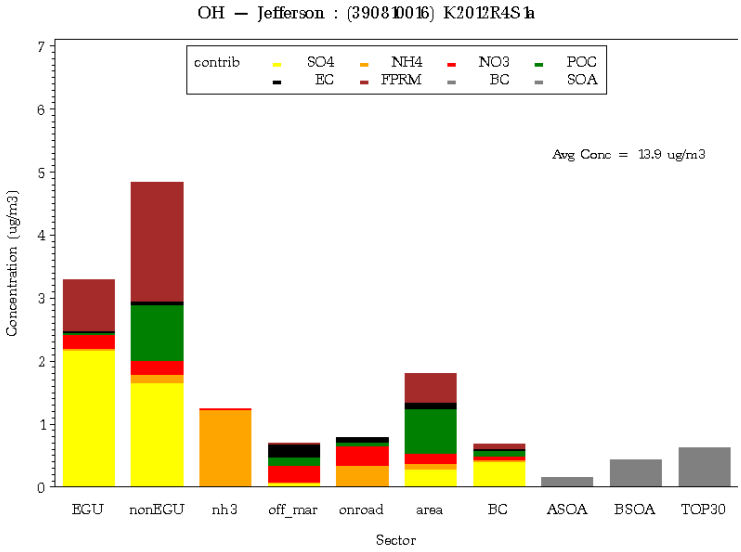
Steubenville, Ohio

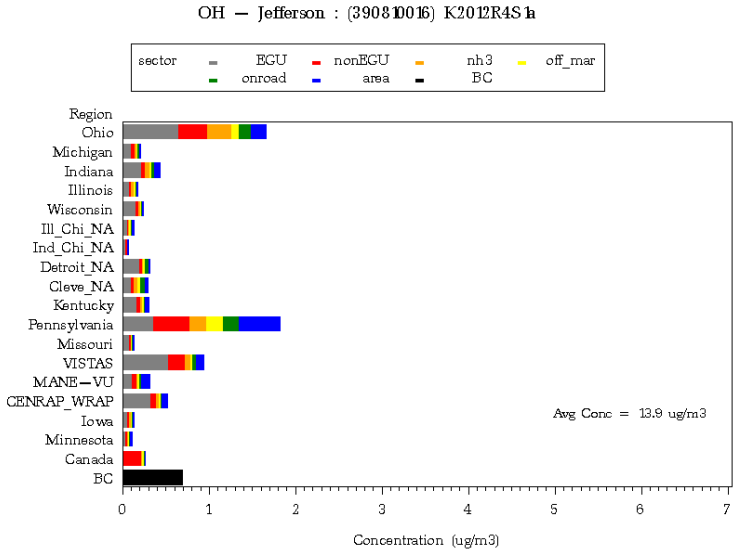
2005 (Round 5)



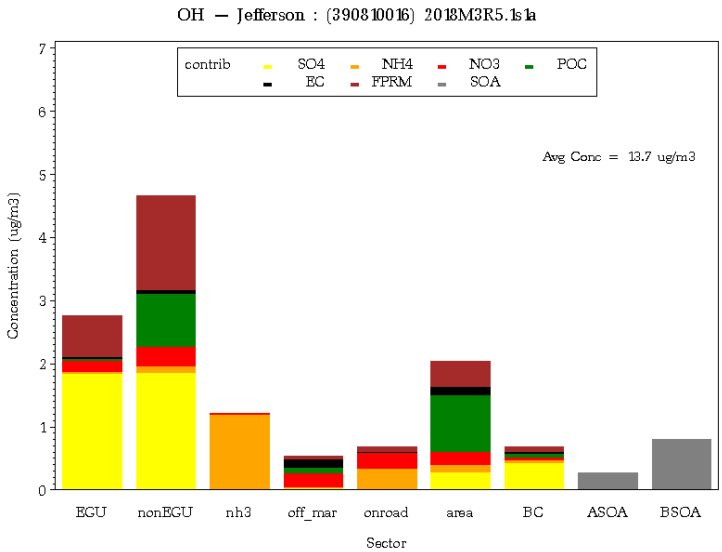


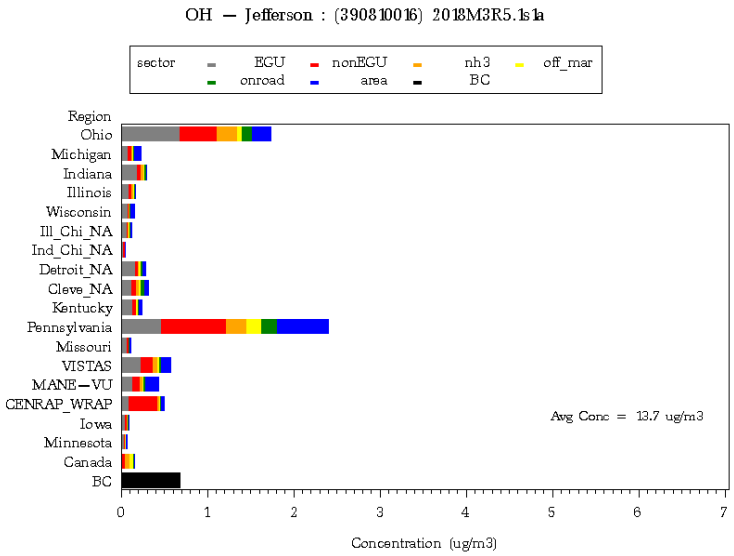
2012 (Round 4)





2018 (Round 5)



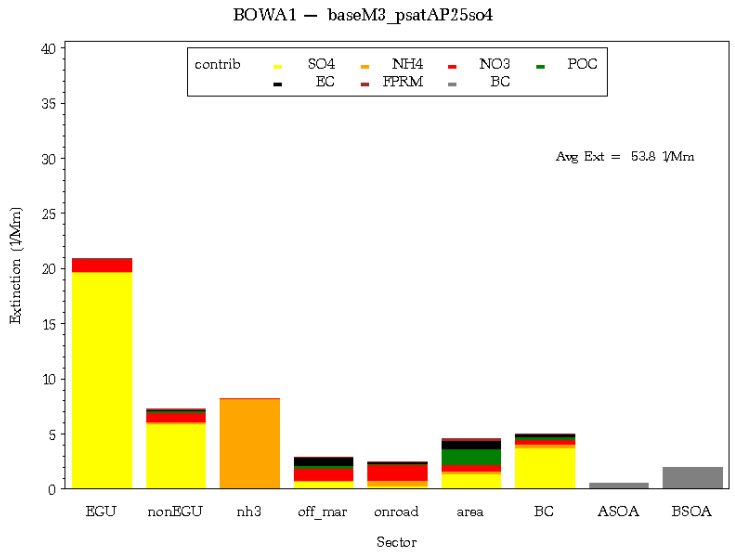


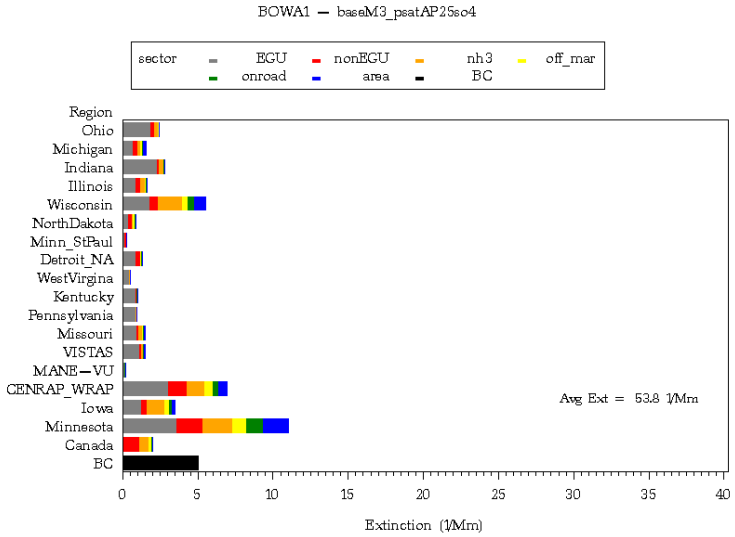
APPENDIX IV

Haze Source Apportionment Modeling Results

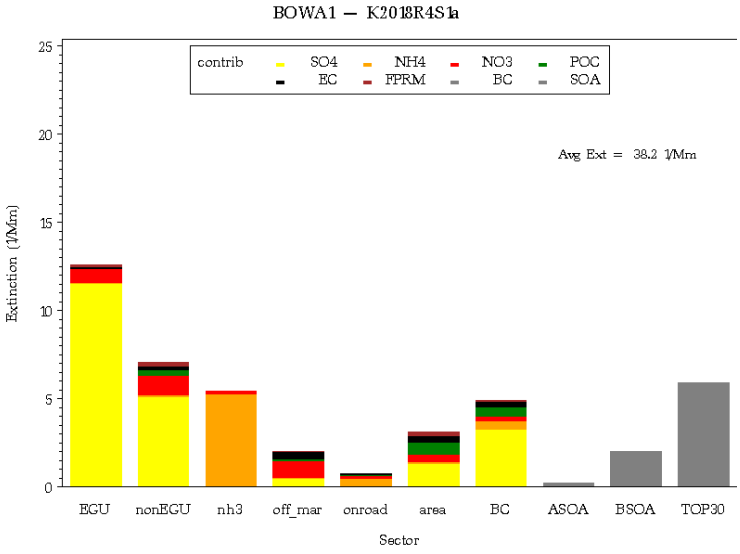
Boundary Waters, Minnesota

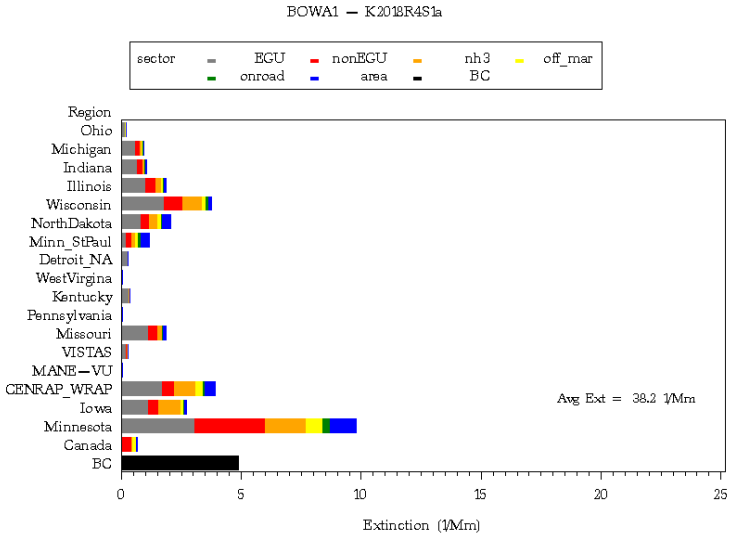
2005 (Round 5)



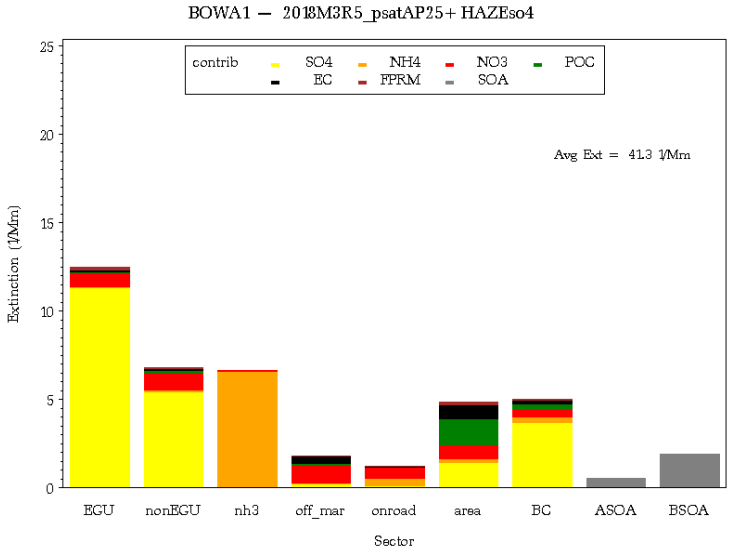


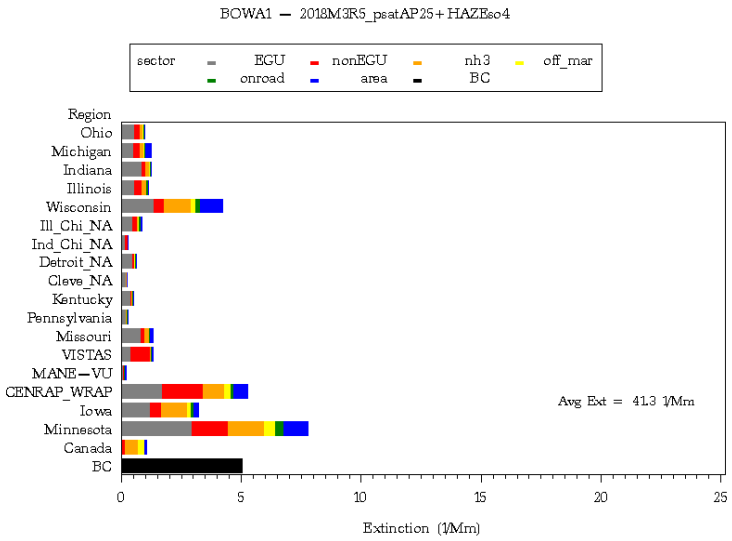
2018 (Round 4)





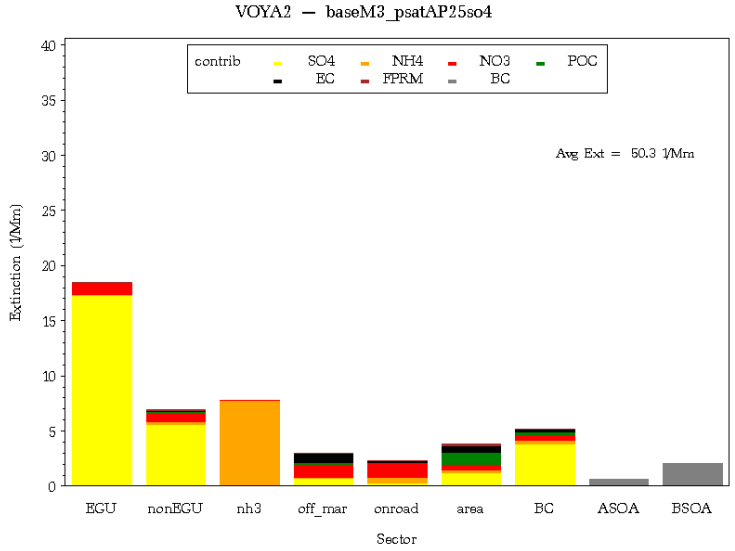
2018 (Round 5)

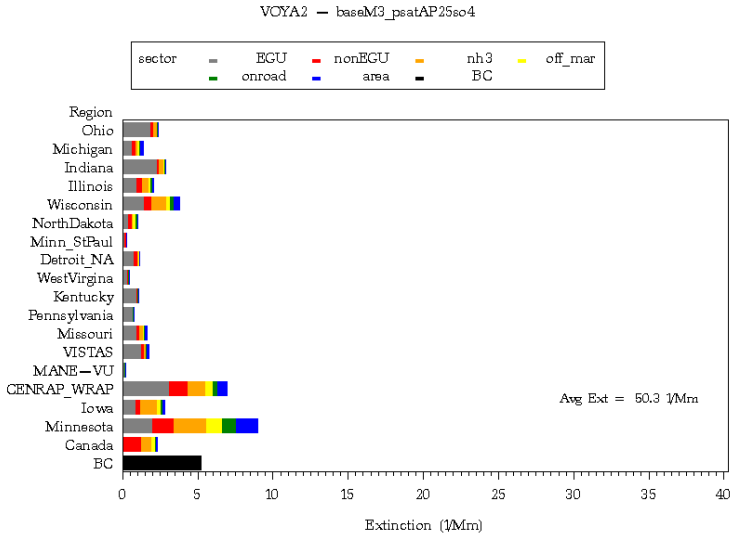




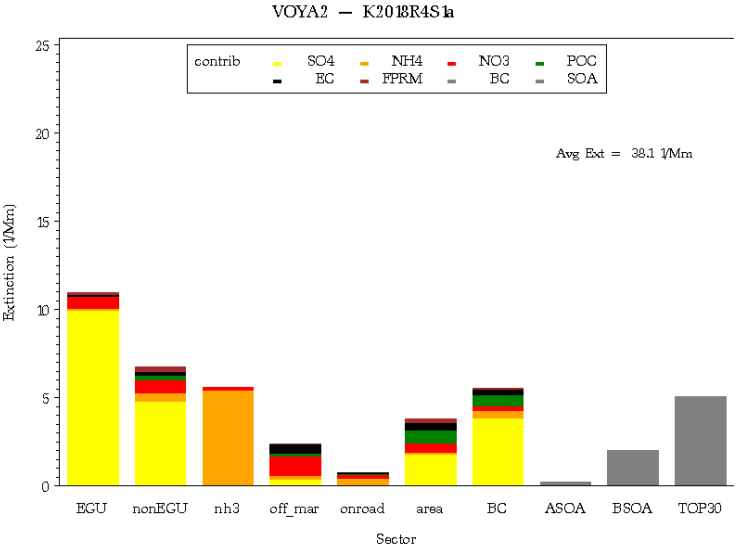
Voyageurs, Minnesota

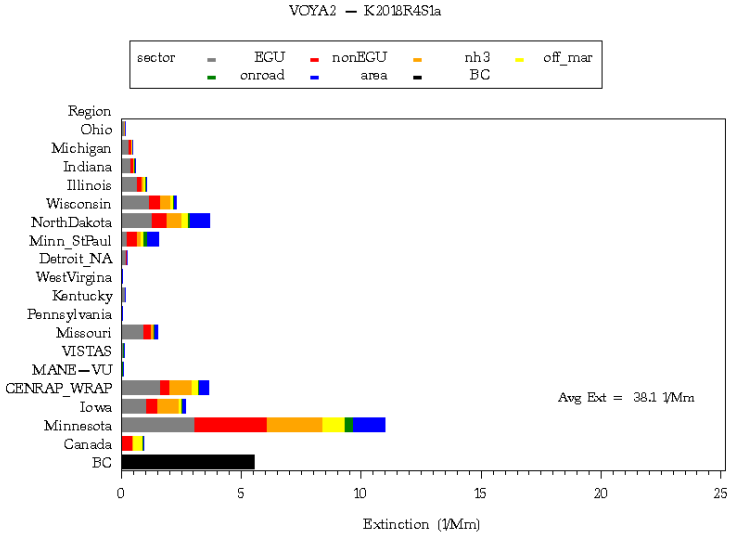
2005 (Round 5)



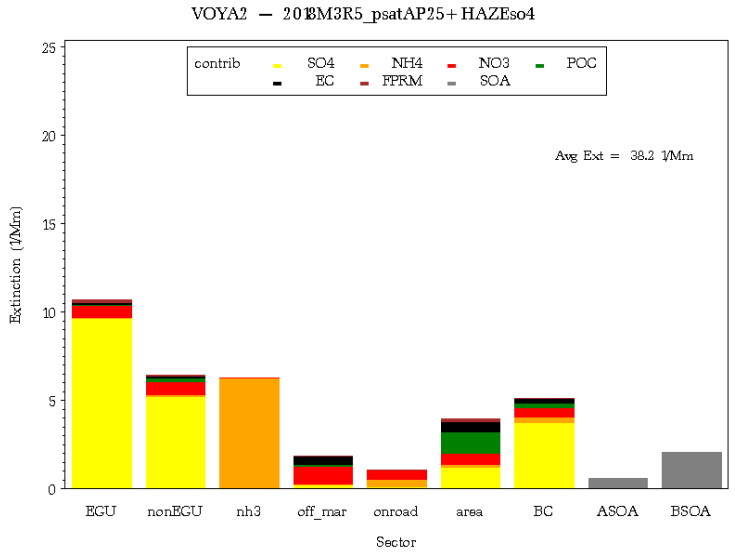


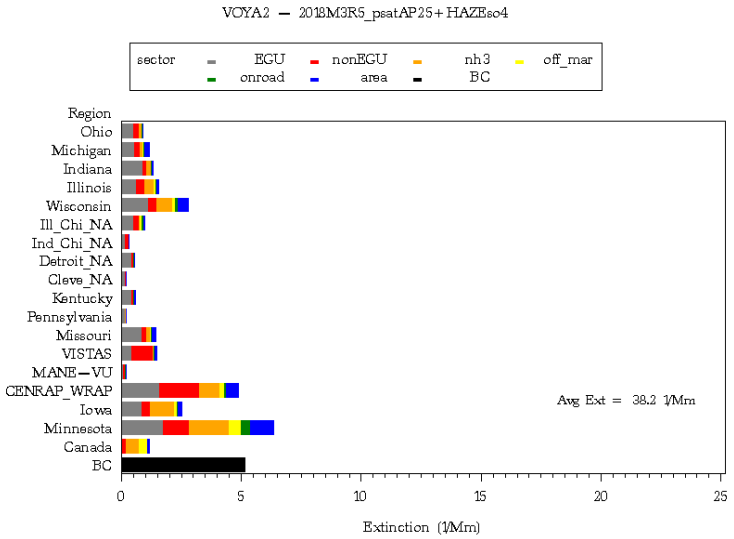
2018 (Round 4)





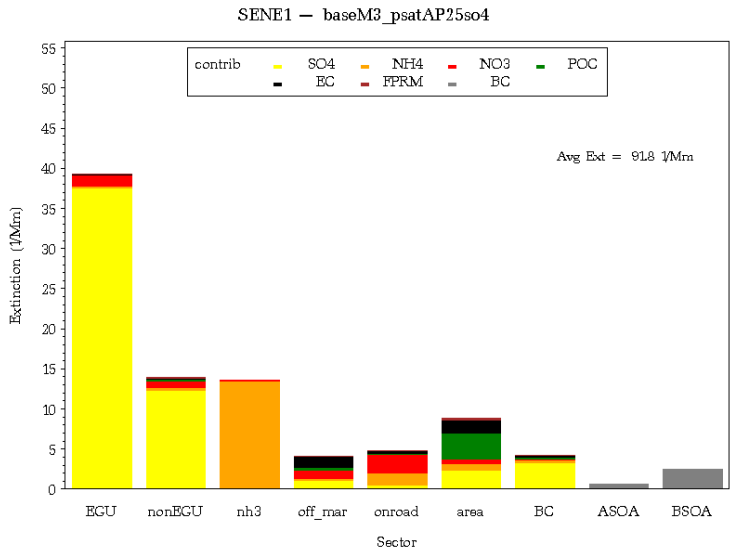
2018 (Round 5)

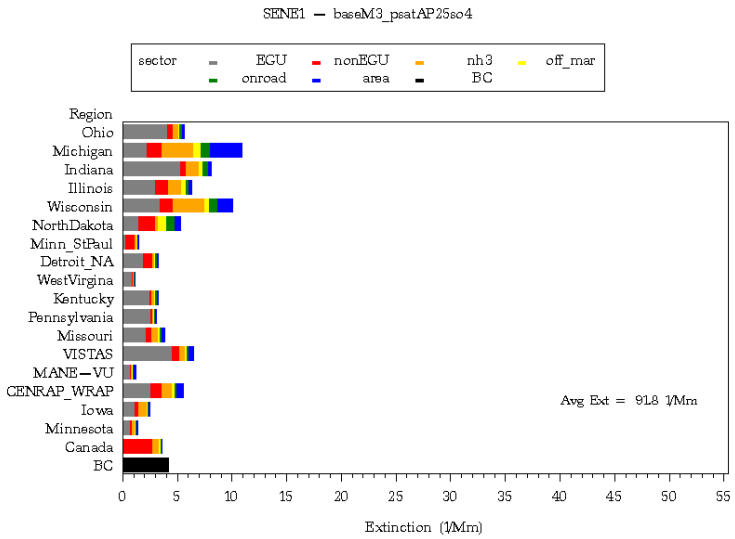




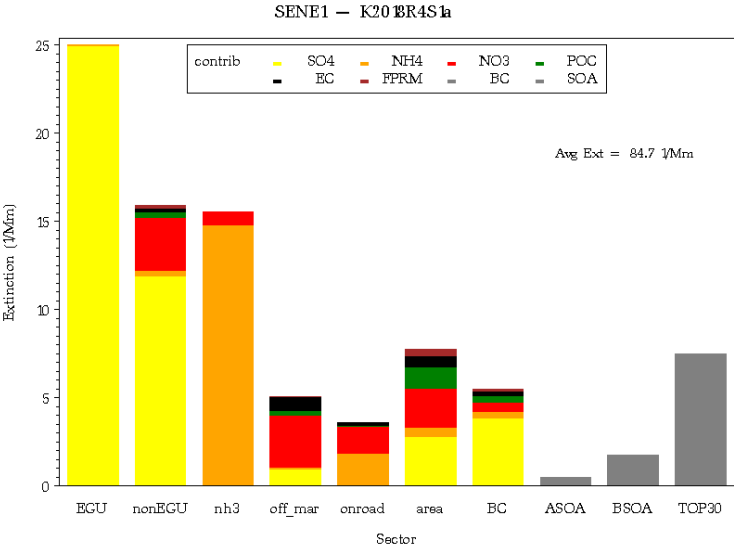
Seney, Michigan

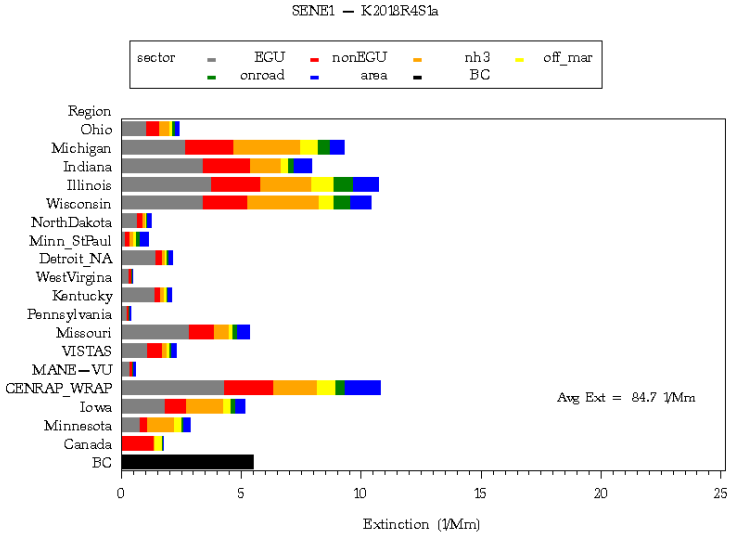
2005 (Round 5)



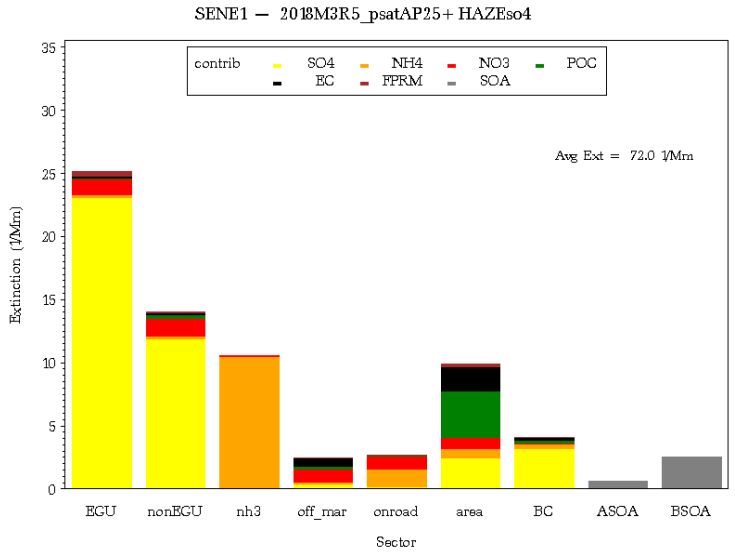


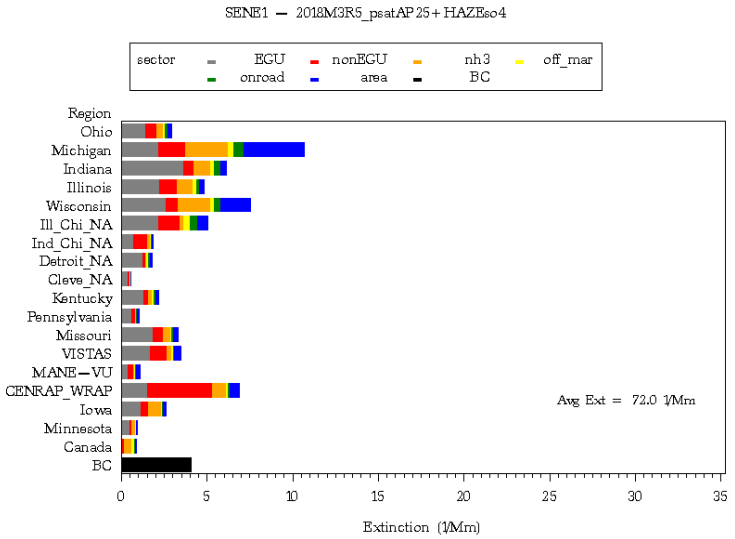
2018 (Round 4)





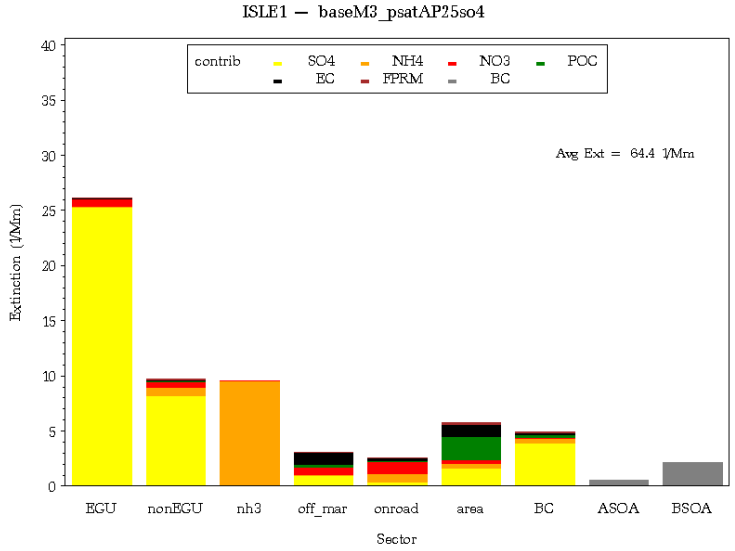
2018 (Round 5)

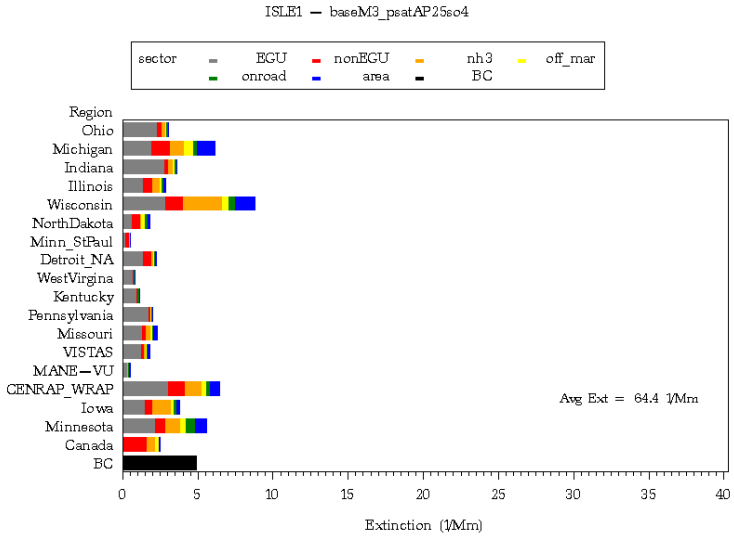




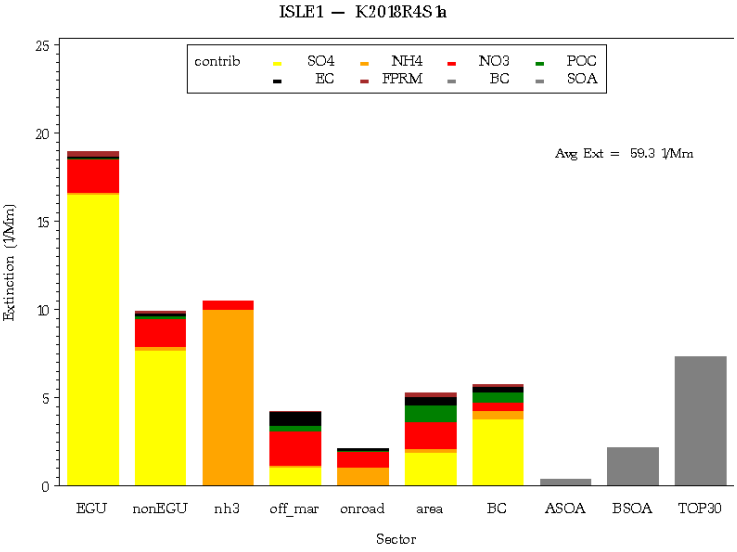
Isle Royale, Michigan

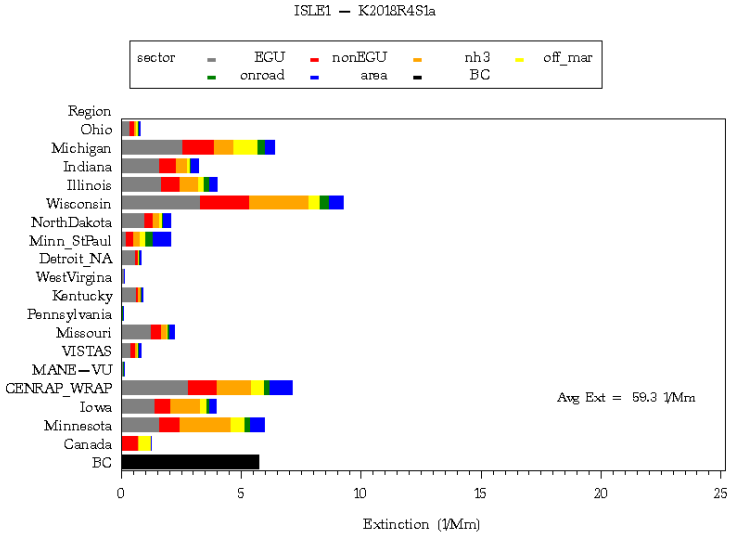
2005 (Round 5)



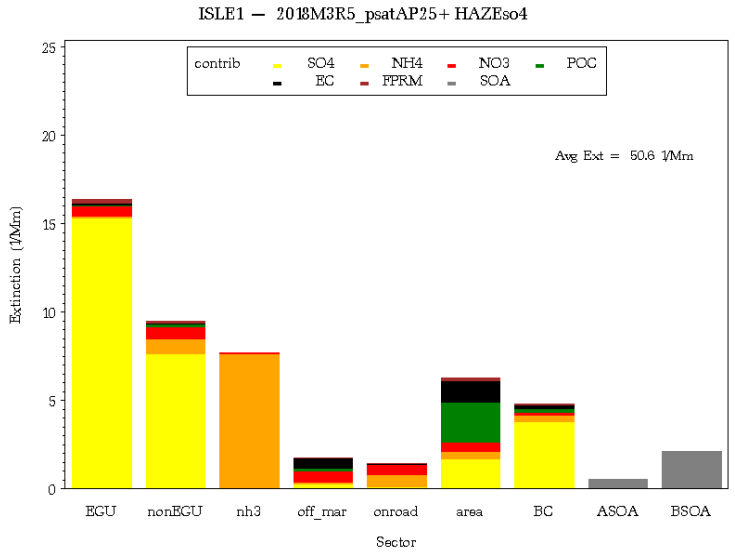


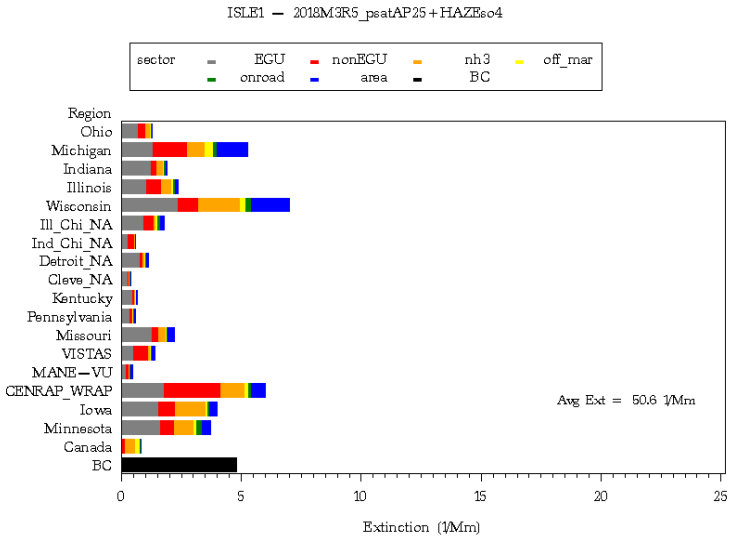
2018 (Round 4)





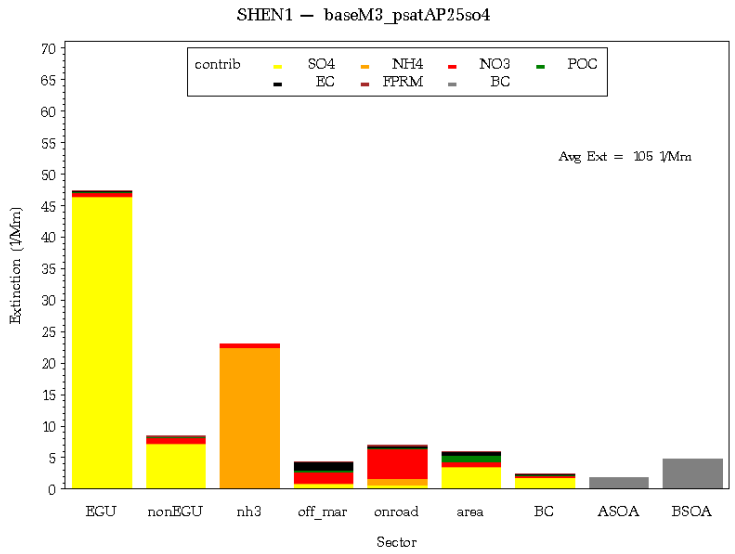
2018 (Round 5)

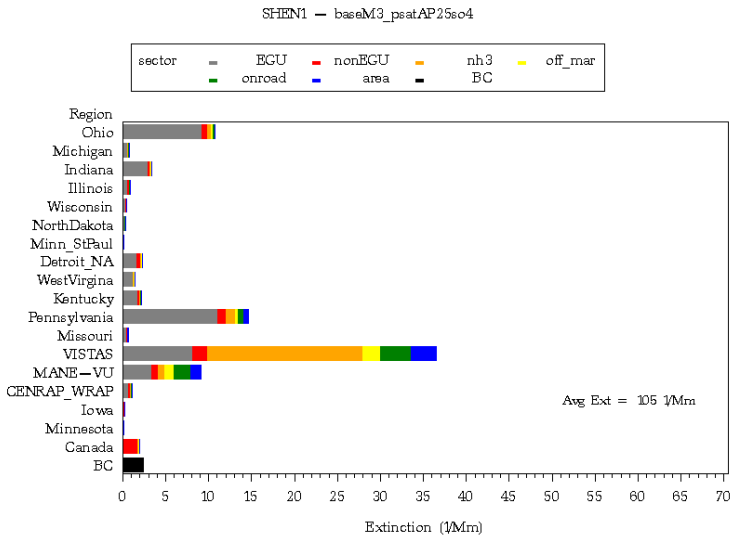




Shenandoah, Virginia

2005 (Round 5)





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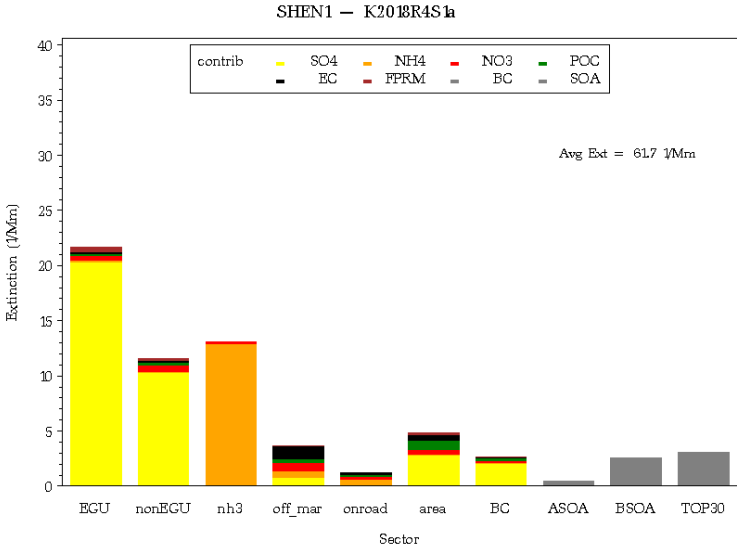

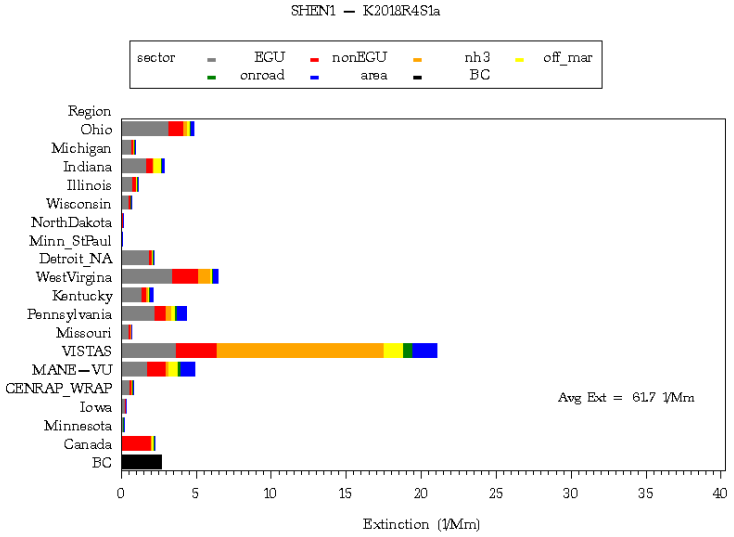

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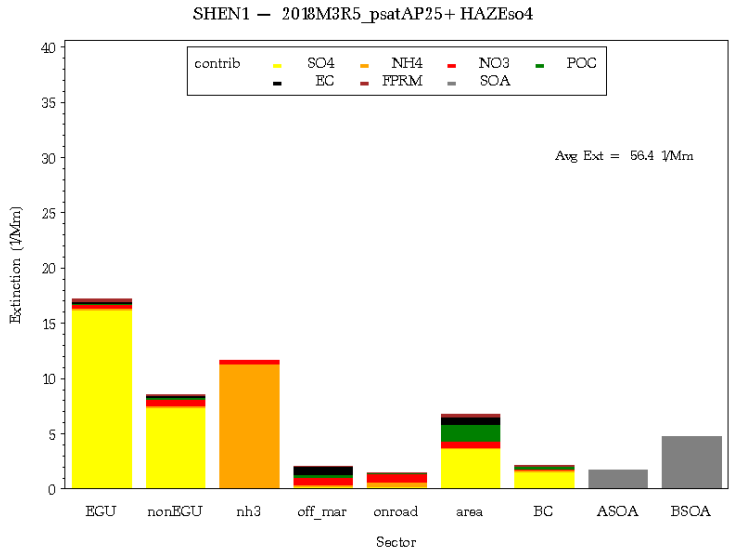
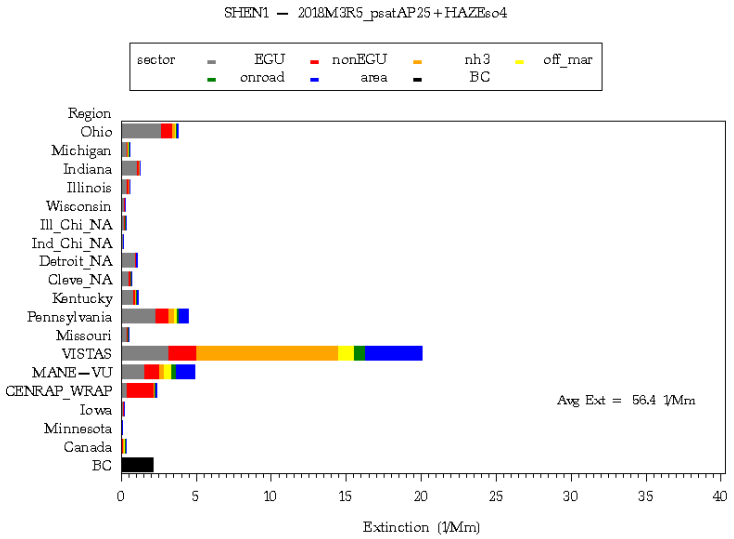
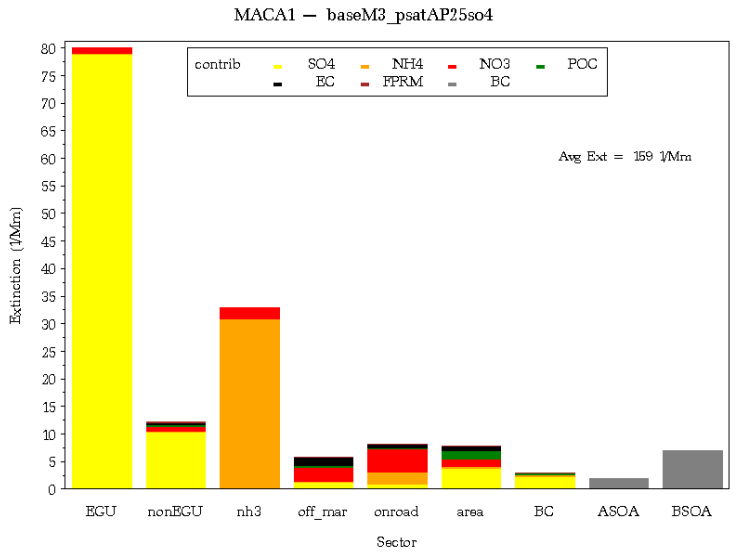
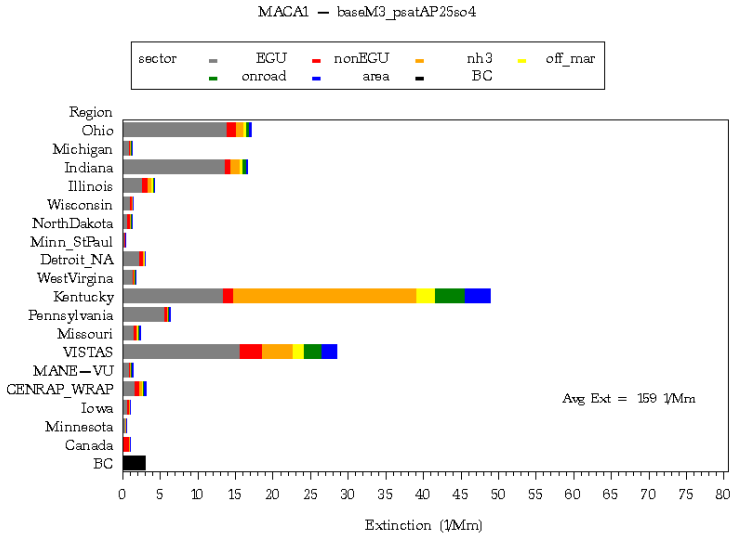




Mammoth Cave, Kentucky

2005 (Round 5)





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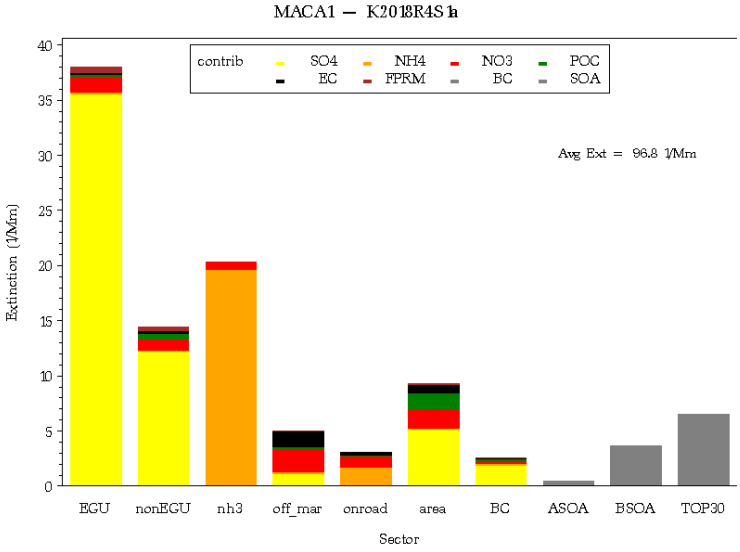

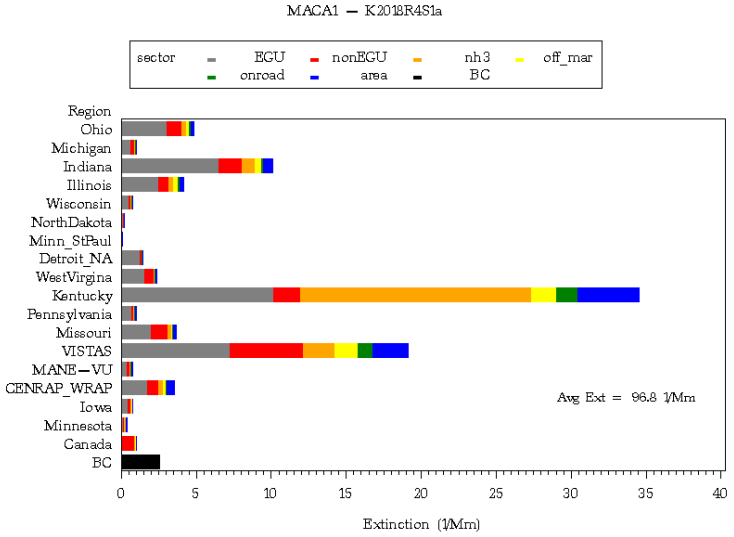

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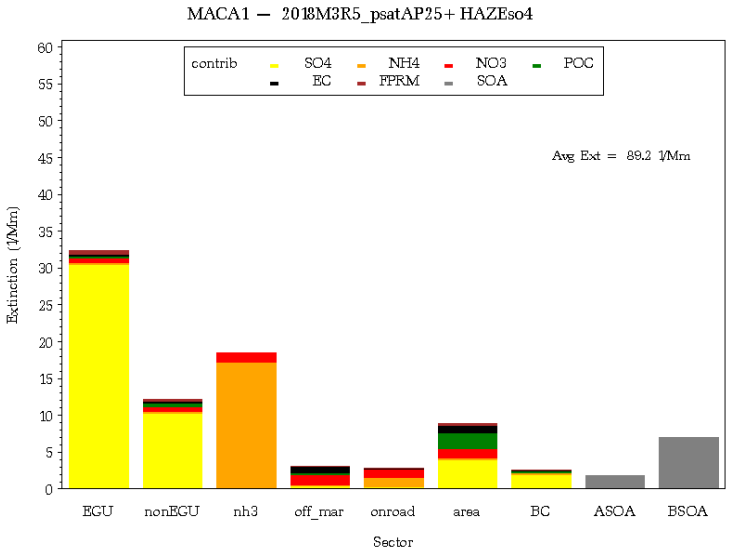
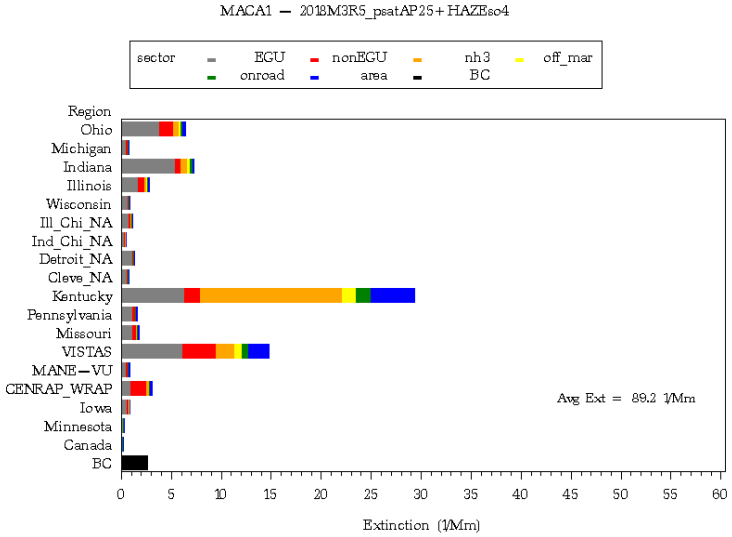
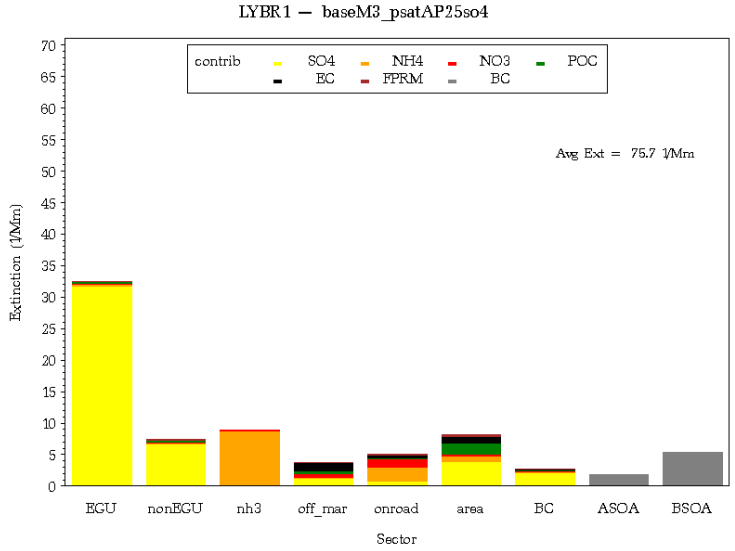
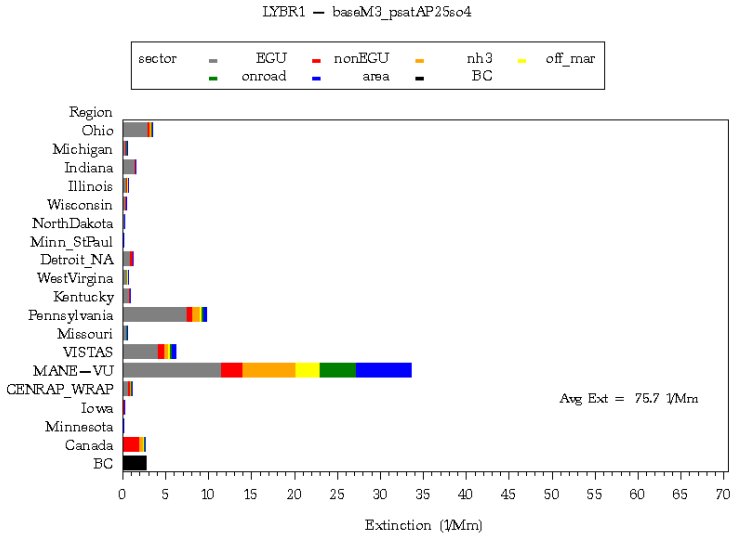




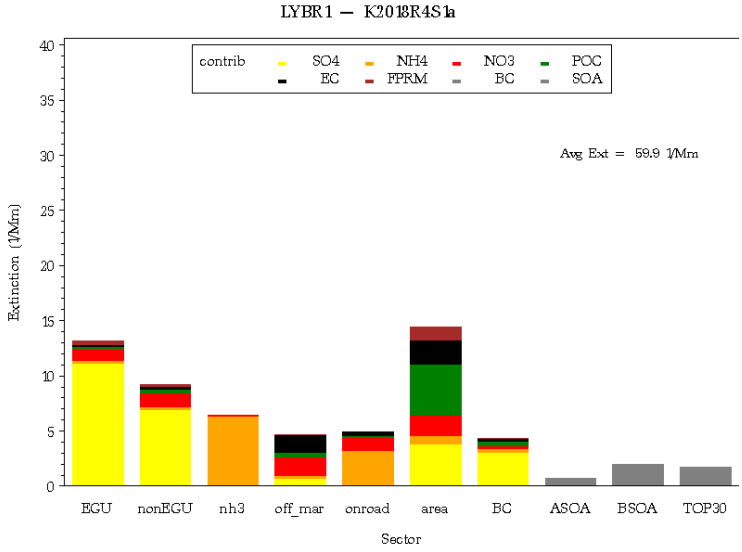
Lye Brook, Vermont

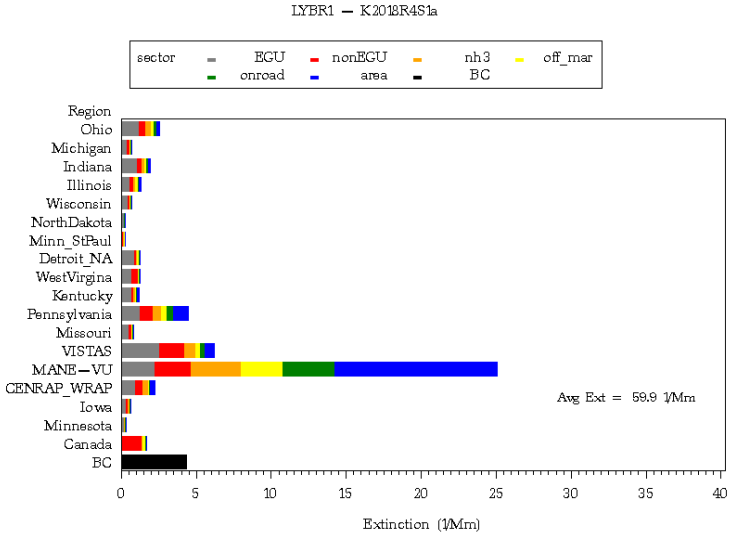
2005 (Round 5)



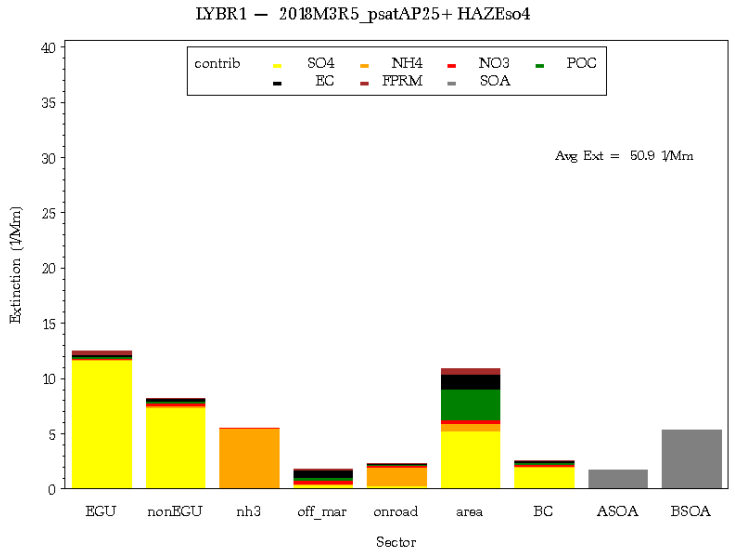


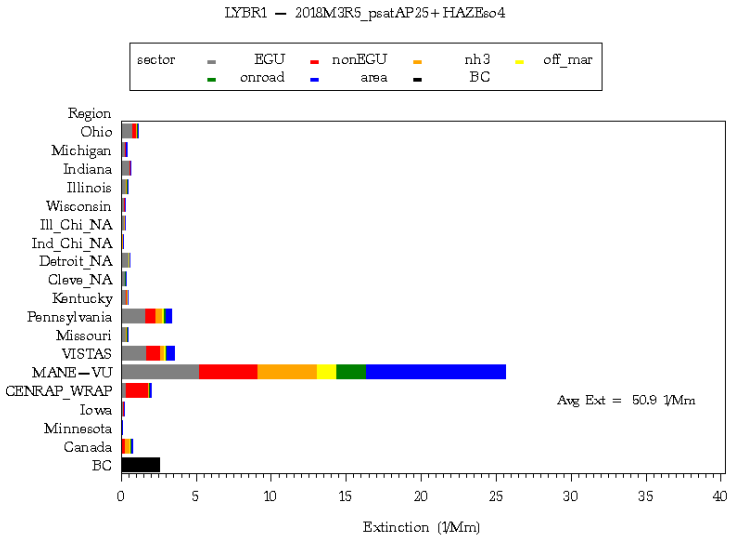
2018 (Round 4)





2018 (Round 5)





Regional Air Quality Analyses for Ozone, PM2.5, and Regional Haze: Final Technical Support Document (Supplement), September 12, 2008

The purpose of this paper is to summarize a new modeling analysis performed by the Lake Michigan Air Directors Consortium (LADCO) to address the effect of the recent court decision vacating EPA's Clean Air Interstate Rule (CAIR). This new modeling is intended to supplement the LADCO Technical Support Document ("Regional Air Quality Analyses for Ozone, PM2.5, and Regional Haze: Final Technical Support Document", April 25, 2008), which summarizes the air quality analyses conducted by LADCO and its contractors to support the development of State Implementation Plans for ozone, PM2.5, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin.

Compared to the previous LADCO modeling (Round 5.1), the new modeling shows similar results for ozone, but much more nonattainment for PM2.5 and higher visibility levels for regional haze. Specifically, the new modeling shows:

> **Ozone:** Attainment of the 0.08 ppm standard by 2009 everywhere in the region, except Holland, MI, and nonattainment of the 0.075 ppm standard through at least 2018.
>
> **PM2.5**: Widespread nonattainment of annual (15 ug/m^3) and daily (35 ug/m^3) standards.
>
> **Haze:** Higher visibility levels on the 20% worst visibility days in 2018 in Class I areas in the eastern U.S., resulting in most areas being above the glide path.

Background: On July 11, 2008, the U.S. Court of Appeals for D.C. Circuit vacated EPA's CAIR rule (cite). The reductions in NOx and SO2 emissions associated with this rule were a key part of the LADCO States' attainment demonstrations for ozone and PM2.5 and the reasonable progress determinations for regional haze. LADCO's previous modeling (Round 5.1) relied on EGU emission projections from EPA's IPM3.0 analysis, which assumed implementation of Phases I and II of CAIR. For this new modeling, alternative EGU emission projections were developed, which did not rely on CAIR (or IPM).

Model Set-Up: The new modeling was performed consistent with LADCO's previous modeling (Round 5.1):

Model Version: CAMx v4.50beta_deposition
Future Years: 2009, 2012, 2018
Runs: (a) Ozone: Summer 2005 meteorology with 12 km grids
(b) PM2.5 and haze: Full year 2005 meteorology with 36 km grids

Emission Scenarios: The new modeling assumed the same set of "on the books" controls as in LADCO's previous modeling (Round 5.1) for all sectors, except EGUs. In light of the CAIR decision, three new EGU scenarios were prepared:

Scenario A: 2007 CEM-based emissions were projected for all states in the modeling domain based on EIA growth rates by state (NERC region) and fuel type. The assumed growth rates for the Midwest States were: MAIN (IL, IA, MO, WI): 8.8% (2007-2018); ECAR (IN, KY, MI, OH): 13.5% (2007-2018); and MAPP (MN): 15.1% (2007-2018). No control was applied. The annual emissions were temporalized based on profiles derived from 2004-2006 CEM data. (Note, these are the same temporal profiles used in Round 5.1.)

Scenario B. Scenario A emissions for the LADCO States and select neighboring states (e.g., MN, IA, MO, KY, TN, and WV) were adjusted by applying legally enforceable controls (i.e., emission reductions required by a Consent Decree, state rule, or permit). Only those legally enforceable controls identified (and justified) by the States were applied. The States also supplied the appropriate control factors. A table summarizing the Scenario B controls is provided in Appendix I.

Scenario C. For the years 2009 and 2012, Scenario A emissions for all states were adjusted by applying all planned SO2 and NOx controls based on the July 10 CAMD list (i.e., 90% reduction for scrubbers, 95% reduction for SCRs). Because the July 10 CAMD list only includes controls generally out to 2011, additional SO2 and NOx controls for the year 2018 were assumed for all BART-eligible EGUs in the five LADCO State plus MN, IA, MO, KY, TN, and MO list (i.e., 90% reduction for scrubbers, 95% reduction for SCRs).[1] All Scenario B controls were included in Scenario C. A table summarizing the Scenario C controls is provided in Appendix II.

Table 1 and Figure 1 provide a summary of the 5-state regional NOx and SO2 emissions for each scenario and future year. (Note, the CAIR emissions included here are based on EPA's IPM3.0 modeling.) Several comments on the emissions should be noted:

Summer NOx

- There is llittle difference between the three alternative scenarios and CAIR. This suggests that summer ozone concentrations for the alternative scenarios are likely to be similar to those predicted with CAIR (i.e., Round 5.1).

Annual NOx:

- There is a significant change in emissions between scenarios, mostly during the non-summer months.
- Scenario B reflects application of NOx controls in several states (e.g., IL,OH,WI).
- Because there are relatively few SCRs (in the LADCO States) on the CAMD list, Scenario C results in only a small emissions decrease compared to Scenario B.
- Assumed BART controls result in a significant emissions decrease.

Annual SO2

- There is a significant change in emissions between scenarios.
- Scenario B reflects application of SO2 controls in several states (e.g., IL,OH,WI).
- Because there are several FGDs (in the LADCO States) on the CAMD list, Scenario C results in a large emissions decrease compared to Scenario B.
- Assumed BART controls result in a significant emissions decrease (i.e., even lower emissions than the IPM-estimated CAIR emissions).

[1] A subsequent analysis was conducted with the following inventory changes: (a) 95% reduction for scrubbers, 90% redcuction for SCRs (consistent with EPA's default assumptions for IPM), and (b) revisions provided for a few plants in Indiana and Minnesota. The changes resulted in a relatively small difference in the regioinal NOx and SO2 emissions (e.g., about a 2% NOx increase and about a 1-2% decrease in SO2). To assess the impact of the changes, PM2.5 modleing was conducted with the new Scenario B and Scenario C emissions for 2012. The modeling showed little change in the predicted PM2.5 concentrations.

Figure 1. Regional NOx and SO2 Emissions

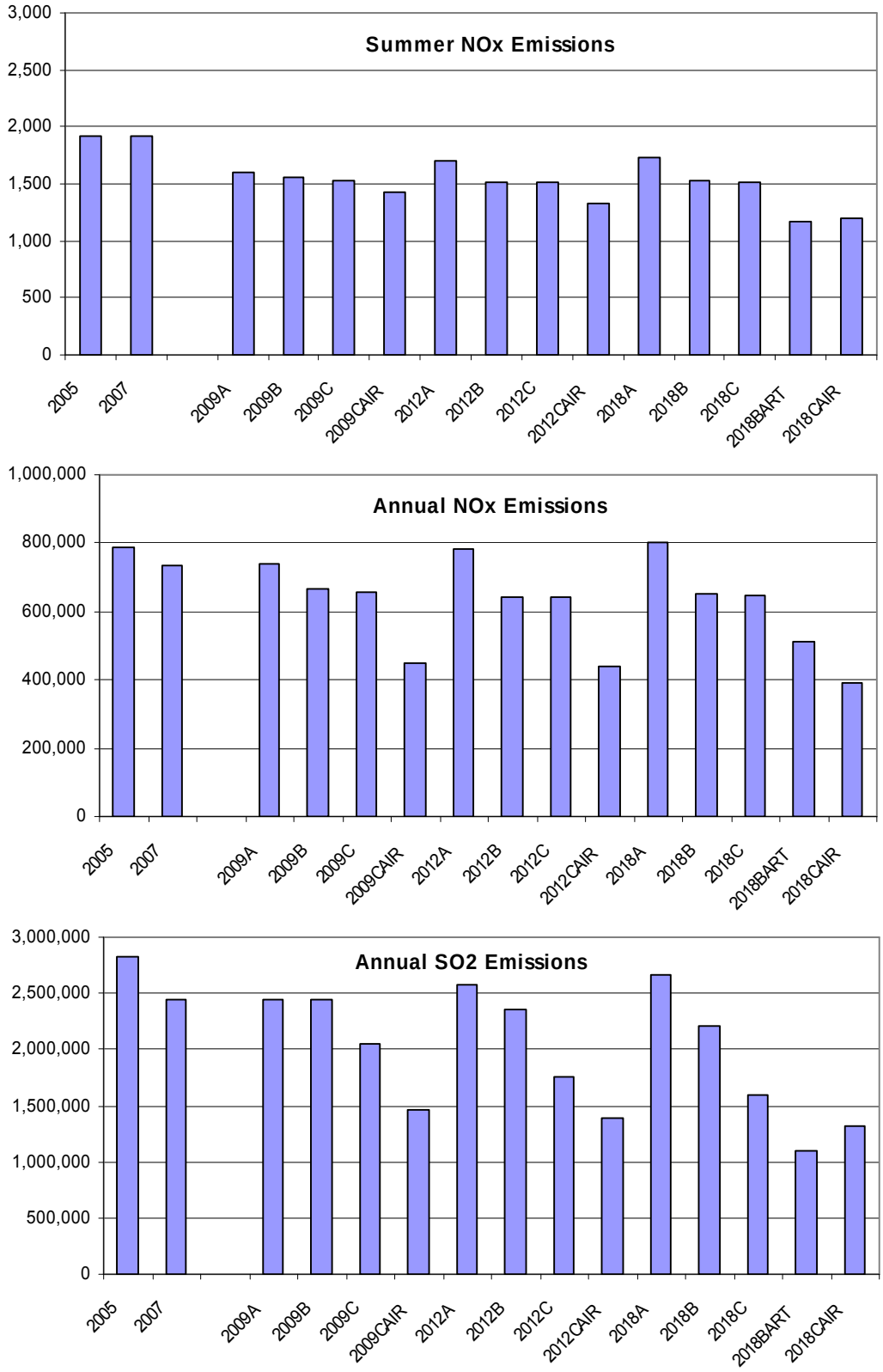


Table 1. Regional NOx and SO2 Emissions

Summer NOx Emissions (TPD)																
	2005	2007		2009 A	2009 B	2009 C	2010 CAIR	2012 A	2012 B	2012 C	2012 CAIR	2018 A	2018 B	2018 C	2018 C-BART	2018 CAIR
IL	305	305		311	311	311	275	340	236	236	266	333	227	227	219	224
IN	393	393		376	376	374	384	393	393	390	368	410	386	383	292	264
MI	393	393		350	350	350	242	366	366	366	229	377	377	377	260	243
OH	408	408		395	355	335	285	423	351	351	290	431	366	366	230	290
WI	413	413		167	160	160	238	184	170	170	177	183	168	168	168	177
	1,912	**1,912**		**1,599**	**1,552**	**1,530**	**1,424**	**1,706**	**1,516**	**1,513**	**1,330**	**1,734**	**1,524**	**1,521**	**1,169**	**1,198**

Annual NOx Emissions (TPY)																
	2005	2007		2009 A	2009 B	2009 C	2010 CAIR	2012 A	2012 B	2012 C	2012 CAIR	2018 A	2018 B	2018 C	2018 C-BART	2018 CAIR
IL	126,786	121,006		124,917	124,917	124,917	83,224	137,438	81,989	81,989	82,248	135,983	79,771	79,771	63,590	69,958
IN	214,727	203,493		203,776	203,776	201,947	133,188	212,790	212,790	210,877	125,541	221,950	212,805	210,810	177,027	90,415
MI	120,332	112,484		112,478	112,478	112,478	83,117	117,621	117,621	117,621	77,897	122,447	122,447	122,447	89,444	79,543
OH	255,554	240,351		240,016	173,071	164,911	94,346	251,065	172,514	172,514	97,679	261,644	179,737	179,737	125,762	95,678
WI	71,414	54,582		56,540	54,065	54,065	53,032	62,266	57,759	57,759	56,480	61,812	56,952	56,952	56,952	56,158
	788,812	**731,917**		**737,727**	**668,307**	**658,317**	**446,908**	**781,179**	**642,673**	**640,760**	**439,845**	**803,837**	**651,712**	**649,717**	**512,774**	**391,752**

Annual SO2 Emissions (TPY)																
	2005	2007		2009 A	2009 B	2009 C	2010 CAIR	2012 A	2012 B	2012 C	2012 CAIR	2018 A	2018 B	2018 C	2018 C-BART	2018 CAIR
IL	326,598	273,467		281,028	281,028	281,028	295,516	309,209	196,238	194,746	267,110	305,364	106,638	105,152	82,351	275,716
IN	866,964	722,301		721,252	721,252	619,486	374,335	754,323	754,323	558,567	379,144	786,551	764,065	559,945	426,695	359,915
MI	350,694	343,487		343,140	343,140	315,326	227,296	358,879	358,879	301,062	233,204	373,964	373,964	313,677	178,680	242,853
OH	1,100,510	960,820		959,466	959,466	693,438	427,145	1,003,633	897,099	572,807	370,532	1,045,945	819,770	481,623	333,740	315,560
WI	181,426	137,562		142,007	142,007	133,738	139,181	156,659	144,818	133,592	139,203	155,818	144,027	132,849	77,214	127,073
	2,826,192	**2,437,638**		**2,446,892**	**2,446,892**	**2,043,017**	**1,463,473**	**2,582,703**	**2,351,356**	**1,760,775**	**1,389,192**	**2,667,641**	**2,208,463**	**1,593,245**	**1,098,679**	**1,321,116**

Modeling Results: Several tables summarizing the modeling results are provided:

Table 2 - future year ozone and PM2.5 concentrations for key monitors in the LADCO region

Table 3 - number of monitoring sites greater than the National Ambient Air Quality Standards (NNAQS)

Table 4 – visibility levels for Class I areas in the eastern U.S.

Note, given that Scenario B and BART controls were only applied in an 11-state Midwest region, the validity of the results for other Class I areas in the eastern U.S. may be questionable. The Scenario C controls, on the other hand, cover all states and are, thus, likely valid in other Class I areas.

Spatial plots of the future year ozone and PM2.5 concentrations are provided in Figures 2 – 4.

Based on these results, the following key findings should be noted:

Ozone

- There is little change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows attainment of the 0.08 ppm (85 ppb) standard by 2009, except Holland. (Note, Holland does meet this standard by 2012.)
- The modeling shows nonattainment of the 0.075 ppm (75 ppb) standard through 2018.

PM2.5 - Annual

- There is a significant change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows extensive nonattainment of the annual standard.

PM2.5 - Daily

- There is a significant change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows extensive nonattainment of the daily standard.

Haze

- There is a significant change from the previous LADCO modeling (Round 5.1 with CAIR)
- The modeling shows higher visibility levels in 2018 for the 20% worst visibility days (average about 0.5 deciviews for the northern Class I areas). The resulting visibility levels in the northern Class I areas (except Voyageurs) are above the glide path.

Table 2a. Ozone Modeling Results

		2005	2009				2012				2018				
			Round 5 without CAIR			Round 5 with CAIR	Round 5 without CAIR			Round 5 with CAIR	Round 5 without CAIR				Round 5 with CAIR
Site	Site ID	Base Year	Scen. A	Scen. B	Scen.C		Scen. A	Scen. B	Scen.C		Scen. A	Scen. B	Scen.C	Scen.C-BART	
Lake Michigan Area															
Chiwaukee	550590019	84.7	82.2	82.2	82.0	82.3	81.1	80.8	80.6	80.9	77.2	77.2	77.0	76.0	76.2
Racine	551010017	80.3	77.8	77.8	77.5	77.5	76.6	76.2	76.1	76.1	72.9	72.3	72.1	71.1	71.2
Milwaukee-Bayside	550890085	82.7	79.9	79.9	79.7	79.8	78.5	78.0	78.0	78.0	74.3	73.6	73.4	72.4	72.7
Harrington Beach	550890009	83.3	80.1	80.1	79.9	80.1	78.6	78.1	78.0	78.3	73.9	73.2	73.1	72.2	72.5
Manitowoc	550710007	**85.0**	80.8	80.8	80.7	80.8	79.0	78.5	78.4	78.6	73.9	73.2	73.1	72.0	72.5
Sheboygan	551170006	**88.0**	84.1	84.0	83.9	84.0	82.2	81.7	81.5	81.8	76.9	76.0	75.9	74.8	75.4
Kewaunee	550610002	82.7	78.2	78.2	78.0	78.1	76.4	75.9	75.7	75.9	71.3	70.7	70.5	69.4	69.9
Door County	550290004	**88.7**	84.1	84.1	83.9	83.9	82.0	81.4	81.3	81.5	76.5	75.6	75.5	74.2	74.7
Hammond	180892008	77.7	76.2	76.2	76.0	75.4	75.6	75.3	75.2	74.6	73.2	72.7	72.6	71.7	71.6
Whiting	180890030	79.3	77.8	77.8	77.7	77.0	77.2	76.9	76.8	76.2	74.8	74.3	74.2	73.2	73.1
Michigan City	180910005	77.0	74.5	74.5	74.3	73.9	73.3	72.9	72.8	72.5	69.7	69.2	69.1	68.1	68.1
Ogden Dunes	181270020	78.3	76.3	76.3	76.2	75.6	75.5	75.1	75.0	74.5	72.9	72.3	72.1	71.2	70.8
Holland	260050003	**90.0**	**85.7**	**85.7**	**85.5**	**85.3**	83.5	83.1	82.9	82.8	78.2	77.5	77.3	76.0	76.1
Jenison	261390005	82.0	76.8	76.8	76.7	76.0	75.1	74.6	74.5	74.5	70.2	69.6	69.5	67.9	68.7
Muskegon	261210039	**85.0**	80.6	80.6	80.5	80.5	78.6	78.2	78.1	78.0	73.5	72.8	72.8	71.5	71.9
Indianapolis Area															
Noblesville	189571001	82.7	78.3	78.3	78.1	78.1	76.1	75.9	75.7	75.6	70.2	69.9	69.8	68.9	68.7
Fortville	180590003	78.0	74.1	74.1	73.9	73.9	71.9	71.8	71.7	71.4	66.7	66.5	66.3	65.4	65.1
Fort B. Harrison	180970050	78.7	75.4	75.3	75.2	75.1	73.8	73.6	73.6	73.2	70.6	70.3	70.2	69.3	69.1
Detroit Area															
New Haven	260990009	86.0	82.4	82.3	82.1	81.4	81.4	81.2	81.1	80.2	78.1	77.8	77.7	76.5	76.1
Warren	260991003	84.0	82.4	82.3	82.2	81.3	82.1	81.8	81.7	80.7	79.7	79.4	79.3	78.0	77.6
Port Huron	261470005	82.7	78.2	78.2	78.1	77.5	76.5	76.3	76.2	75.5	72.6	72.5	72.3	70.9	70.9
Cleveland Area															
Ashtabula	390071001	**89.0**	84.2	84.1	83.9	83.4	82.0	81.8	81.6	81.0	76.8	76.5	76.4	74.8	75.1
Geauga	390550004	79.3	75.8	75.8	75.6	74.7	74.0	73.8	73.7	72.7	69.5	69.2	69.1	67.6	67.3
Eastlake	390850003	**86.3**	83.1	83.1	82.9	81.9	81.8	81.6	81.5	80.5	78.2	78.0	77.8	76.5	76.2
Akron	391530020	83.7	79.1	79.1	79.0	78.1	76.9	76.7	76.6	75.6	70.9	70.6	70.4	68.7	68.7
Cincinnati Area															
Wilmington	390271002	82.3	77.3	77.4	77.1	77.5	75.3	75.2	74.8	74.9	70.1	69.9	69.5	67.1	68.3
Sycamore	390610006	84.7	81.5	81.4	81.1	81.9	80.4	80.2	79.8	80.3	76.4	76.0	75.7	73.5	74.6
Lebanon	391650007	**87.7**	82.8	82.8	82.4	83.0	80.8	80.7	80.3	80.7	75.4	75.1	74.8	72.6	74.2
Columbus Area															
London	390970007	79.7	75.0	75.0	74.8	75.0	73.0	72.8	72.7	72.6	68.1	67.8	67.6	65.9	66.3
New Albany	390490029	**86.3**	82.1	82.1	81.9	81.8	80.2	80.0	79.9	79.6	74.7	74.3	74.2	73.3	73.0
Franklin	290490028	80.3	76.7	76.6	76.5	75.9	75.1	74.9	74.8	74.1	70.5	70.2	70.1	70.2	69.0
St. Louis Area															
W. Alton (MO)	291831002	**86.3**	81.1	81.2	81.1	81.0	80.0	79.9	79.9	78.6	76.9	76.8	76.7	74.2	74.9
Orchard (MO)	291831004	**87.0**	82.1	82.1	82.0	82.0	80.9	80.8	80.7	80.0	77.7	77.6	77.4	75.2	76.2
Sunset Hills (MO)	291890004	82.3	79.2	79.2	79.1	78.7	78.3	78.1	78.1	77.1	75.3	75.2	75.1	73.0	73.9
Arnold (MO)	290990012	82.3	77.8	77.8	77.7	77.2	76.7	76.6	76.5	75.6	73.6	73.4	73.4	71.3	72.0
Margaretta (MO)	295100086	83.0	79.8	79.8	79.7	79.3	78.8	78.7	78.6	77.9	75.7	75.6	75.5	73.7	74.4
Maryland Heights (MO)	291890014	**87.3**	**85.4**	**85.4**	**85.3**	84.0	84.3	84.1	84.0	81.7	81.1	80.9	80.8	78.4	78.1

Table 2b. $PM_{2.5}$ Modeling Results (Annual)

		2005		2009					2012					2018				
				Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR				Round 5 with CAIR
Site	Site ID	Base Year		Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C	Scen.C-BART	
Illinois																		
Chicago - Washington HS	170310022	15.2		14.9	14.8	14.5	14.1		14.8	14.7	14.2	14.0		15.0	14.6	14.2	13.7	13.9
Chicago - Mayfair	170310052	15.8		15.1	15.1	14.8	14.4		15.1	14.9	14.5	14.2		15.1	14.7	14.3	13.7	13.9
Chicago - Springfield	170310057	15.0		14.6	14.6	14.3	13.9		14.6	14.4	14.0	13.8		14.8	14.4	14.0	13.4	13.7
Chicago - Lawndale	170310076	14.9		14.5	14.5	14.2	13.8		14.5	14.3	13.9	13.7		14.7	14.3	13.9	13.3	13.6
Blue Island	170312001	14.8		14.4	14.4	14.0	13.7		14.4	14.2	13.8	13.6		14.5	14.1	13.7	13.2	13.4
Summit	170313301	15.2		14.9	14.9	14.6	14.2		14.9	14.7	14.3	14.0		15.0	14.6	14.3	13.7	13.9
Cicero	170316005	15.5		15.1	15.1	14.8	14.4		15.1	14.9	14.5	14.3		15.2	14.9	14.4	13.9	14.2
Granite City	171191007	16.7		16.3	16.2	15.9	15.1		16.1	16.0	15.3	14.9		15.9	15.6	14.9	14.2	14.3
E. St. Louis	171630010	15.6		15.2	15.2	14.8	14.1		15.0	14.9	14.3	13.9		14.9	14.6	14.0	13.3	13.4
Indiana																		
Jeffersonville	180190005	16.4		15.8	15.7	14.8	13.8		15.8	15.6	14.5	13.7		16.0	15.5	14.3	13.7	13.4
Jasper	180372001	15.2		14.3	14.2	13.4	12.4		14.2	14.0	13.0	12.2		14.3	13.9	12.8	12.1	11.8
Gary	180890031	15.6		13.9	13.9	13.5	13.0		13.8	13.6	13.1	12.8		13.7	13.4	12.9	12.3	12.4
Indy-Washington Park	180970078	15.3		14.4	14.4	13.6	12.8		14.3	14.2	13.2	12.6		14.3	13.9	12.9	12.2	12.0
Indy-W 18th Street	180970081	16.0		15.1	15.1	14.3			15.0	14.9	13.9			15.0	14.6	13.5	12.8	
Indy- Michigan Street	180970083	15.9		15.0	15.0	14.2	13.4		14.9	14.8	13.8	13.1		14.9	14.5	13.5	12.8	12.6
Michigan																		
Allen Park	261630001	14.5		11.0	14.0	13.5	13.0		14.0	13.8	13.2	12.8		13.9	13.6	13.0	12.4	12.4
Southwest HS	261630015	15.9		15.3	15.3	14.8	14.2		15.2	15.0	14.4	13.9		15.1	14.8	14.1	13.5	13.5
Linwood	261630016	14.6		14.1	14.1	13.6	13.1		14.0	13.9	13.3	12.8		13.9	13.6	13.0	12.5	12.5
Dearborn	261630033	17.5		17.0	17.0	16.4	15.8		16.9	16.7	16.0	15.5		16.8	16.4	15.7	15.1	15.1
Wyandotte	261630036	14.7		14.2	14.1	13.6	13.1		14.1	13.9	13.3	12.8		14.0	13.7	13.0	12.4	12.5
Ohio																		
Middletown - Bonita	390170003	16.2		15.3	15.2	14.3	13.5		15.2	15.0	13.9	13.2		15.2	14.8	13.7	13.0	12.8
Fairfield	390170016	15.8		15.1	15.0	14.1	13.1		15.1	14.9	13.7	12.9		15.2	14.7	13.5	12.8	12.5
Cleveland-28th Street	390350027	15.4		14.9	14.9	14.3	13.5		14.7	14.5	13.9	13.2		14.6	14.2	13.5	12.8	12.7
Cleveland-St. Tikhon	390350038	17.4		16.7	16.7	16.0	15.2		16.5	16.3	15.6	14.8		16.3	16.0	15.2	14.4	14.3
Cleveland-Broadway	390350045	16.5		15.9	15.8	15.2	14.4		15.6	15.5	14.8	14.0		15.5	15.1	14.4	13.6	13.5
Cleveland-GT Craig	390350060	17.1		16.5	16.4	15.8	15.0		16.3	16.1	15.4	14.6		16.1	15.7	15.0	14.2	14.1
Newburg Hts - Harvard Ave	390350065	16.0		15.4	15.3	14.7	14.0		15.2	15.0	14.3	13.6		15.1	14.7	14.0	13.2	13.1
Columbus - Fairgrounds	390490024	15.3		14.6	14.5	13.7	12.9		14.4	14.1	13.2	12.6		14.2	13.8	12.8	12.2	12.0
Columbus - Ann Street	390490025	15.1		14.4	14.3	13.5	12.7		14.2	13.9	13.1	12.4		14.1	13.6	12.6	12.0	11.9
Cincinnati - Seymour	390610014	17.3		16.6	16.5	15.5	14.5		16.5	16.3	15.1	14.3		16.6	16.2	14.9	14.2	13.8
Cincinnati - Taft Ave	390610040	15.5		14.8	14.7	13.8	12.8		14.8	14.6	13.4	12.6		14.9	14.5	13.2	12.5	12.2
Cincinnati - 8th Ave	390610042	16.9		12.0	16.1	15.0	14.0		16.1	15.9	14.7	13.8		16.2	15.7	14.4	13.7	13.4
Sharonville	390610043	15.6		14.9	14.8	13.9	12.9		14.9	14.7	13.5	12.7		14.9	14.5	13.3	12.6	12.3
Norwood	390617001	16.2		15.5	15.4	14.4	13.4		15.4	15.2	14.0	13.2		15.5	15.1	13.8	13.1	12.8
St. Bernard	390618001	17.6		16.8	16.7	15.7	14.7		16.7	16.5	15.3	14.4		16.8	16.4	15.1	14.3	14.0
Steubenville	390810016	15.8		14.5	14.4	13.5	12.8		14.3	14.2	13.1	12.5		14.8	14.5	13.3	12.9	12.7
Mingo Junction	390811001	16.5		15.2	15.2	14.3	13.5		15.0	14.9	13.8	13.2		15.6	15.2	14.0	13.6	13.4
Ironton	390870010	15.2		14.8	14.6	13.6	12.8		14.6	14.4	13.2	12.5		14.8	14.1	12.8	12.4	12.3
Dayton	391130032	15.5		14.9	14.8	14.0	13.2		14.8	14.6	13.6	12.9		14.8	14.3	13.3	12.6	12.4
New Boston	391450013	14.7		12.0	14.0	13.0	12.1		14.1	13.8	12.5	11.9		14.2	13.6	12.2	11.7	11.6
Canton - Dueber	391510017	16.3		15.7	15.6	14.8	14.0		15.5	15.3	14.4	13.6		15.4	14.9	14.0	13.3	13.3
Canton - Market	391510020	14.6		11.0	14.1	13.3	12.6		13.9	13.7	12.9	12.3		13.9	13.5	12.6	12.0	11.9
Akron - Brittain	391530017	15.1		14.6	14.5	13.8	13.0		14.4	14.2	13.4	12.7		14.3	13.8	13.0	12.3	12.3
Akron - W. Exchange	391530023	14.3		13.7	13.7	13.0	12.3		13.6	13.3	12.6	12.0		13.4	13.0	12.2	11.6	11.5

Table 2c. $PM_{2.5}$ Modeling Results (Daily)

			2005		2009					2012					2018				
					Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR				Round 5 with CAIR
Key Site	County	Site ID	Base Year		Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C			Scen. A	Scen. B	Scen.C	Scen. C - BART	
Illinois																			
Chicago - Washington HS	Cook	170310022	36.6		36	36	36	36		36	36	37	36		37	36	37	37	35
Chicago - Mayfair	Cook	170310052	40.3		37	37	37	36		37	36	37	36		38	37	37	37	36
Chicago - Springfield	Cook	170310057	37.4		34	34	33	32		35	34	33	32		36	34	33	33	31
Chicago - Lawndale	Cook	170310076	38.1		35	35	35	35		36	35	36	35		36	35	36	36	34
McCook	Cook	170311016	43.0		39	39	39	39		40	39	40	39		40	40	41	40	38
Blue Island	Cook	170312001	37.7		35	35	35	34		36	35	36	34		36	35	36	36	33
Schiller Park	Cook	170313103	41.6		40	40	40	39		40	40	40	39		41	40	40	39	39
Summit	Cook	170313301	40.2		38	38	39	38		39	38	39	38		39	38	39	39	37
Maywood	Cook	170316005	39.2		38	38	38	38		38	38	39	38		39	38	39	39	37
Granite City	Madison	171191007	39.2		36	36	35	33		36	35	34	33		36	35	35	33	32
E. St. Louis	St. Clair	171630010	33.7		31	31	30	28		31	30	29	28		31	30	30	29	28
Indiana																			
Jeffersonville	Clark	180190005	38.4		35	33	31	29		35	34	32	31		37	35	34	33	31
Jasper	Dubois	180372001	36.2		32	32	30	28		32	32	30	29		33	31	31	30	28
Gary - IITRI	Lake	180890022	39.0		35	35	35	34		35	34	35	34		36	36	36	35	35
Gary - Burr School	Lake	180890026	39.0		34	34	34	33		34	34	35	34		34	34	34	34	32
Gary	Lake	180890031	35.2		29	28	26	24		28	28	24	24		29	28	27	27	27
Indy-West Street	Marion	180970043	38.0		34	34	33	33		35	35	34	33		36	35	34	34	33
Indy-English Avenue	Marion	180970066	38.0		34	34	32	32		35	34	33	32		35	34	33	33	32
Indy-Washington Park	Marion	180970078	36.6		33	33	32	31		33	33	32	31		34	33	32	32	32
Indy-W 18th Street	Marion	180970081	38.3		33	33	31	31		33	33	32	31		34	33	32	32	31
Indy- Michigan Street	Marion	180970083	36.0		32	32	29	28		32	31	29	28		32	31	29	29	29
Michigan																			
Luna Pier	Monroe	261150005	38.9		34	34	32	32		34	34	32	32		34	33	32	31	31
Oak Park	Oakland	261250001	39.9		38	38	37	36		38	37	37	36		38	37	37	36	35
Port Huron	St. Clair	261470005	39.6		36	35	35	34		35	35	35	34		35	35	34	33	33
Ypsilanti	Washtenaw	261610008	39.5		37	37	36	35		37	36	36	35		37	36	36	35	34
Allen Park	Wayne	261630001	38.6		36	36	36	35		36	35	35	34		36	35	35	34	33
Southwest HS	Wayne	261630015	40.1		36	36	36	35		36	35	35	35		36	35	35	34	33
Linwood	Wayne	261630016	43.0		40	40	40	39		40	40	40	39		40	39	39	39	38
E 7 Mile	Wayne	261630019	41.0		39	39	39	38		39	39	39	38		39	38	38	38	37
Dearborn	Wayne	261630033	43.9		41	41	41	40		41	41	41	40		41	40	40	40	39
Wyandotte	Wayne	261630036	37.2		36	36	36	35		35	35	35	35		35	35	35	35	34
Newberry	Wayne	261630038	42.7		39	39	39	38		39	38	38	37		39	38	38	37	36
FIA	Wayne	261630039	39.7		35	34	34	33		35	34	34	33		35	34	33	33	31
Ohio																			
Middleton	Butler	390170003	39.3		33	32	29	28		33	33	29	28		34	32	29	28	27
Fairfield	Butler	390170016	37.1		32	31	29	27		31	30	28	28		32	30	29	28	27
	Butler	390170017	40.8		33	32	30	29		33	33	30	29		33	32	30	29	28
Cleveland-28th Street	Cuyahoga	390350027	36.9		34	34	33	32		34	33	33	32		34	33	33	31	31
Cleveland-St. Tikhon	Cuyahoga	390350038	44.2		40	40	37	36		40	39	36	35		40	38	36	35	34
Cleveland-Broadway	Cuyahoga	390350045	38.8		35	35	33	31		35	34	32	30		35	34	31	29	29
Cleveland-GT Craig	Cuyahoga	390350060	42.1		39	39	38	37		39	38	38	37		39	38	37	36	35
Newburg Hts - Harvard Ave	Cuyahoga	390350065	38.9		35	35	33	31		35	34	32	30		36	35	32	31	30
Columbus - Fairgrounds	Franklin	390490024	38.5		34	34	33	33		34	33	32	32		34	34	33	32	31
Columbus - Ann Street	Franklin	390490025	38.5		34	33	31	31		33	33	31	31		34	33	31	31	30
Cincinnait	Hamilton	390610006	40.6		33	33	30	27		33	32	29	28		34	32	29	28	27

Table 2c. $PM_{2.5}$ Modeling Results (Daily)

			2005		2009					2012					2018				
					Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR			Round 5 with CAIR		Round 5 without CAIR				Round 5 with CAIR
Key Site	**County**	**Site ID**	**Base Year**		**Scen. A**	**Scen. B**	**Scen.C**			**Scen. A**	**Scen. B**	**Scen.C**			**Scen. A**	**Scen. B**	**Scen.C**	**Scen. C - BART**	
Cincinnati - Seymour	Hamilton	390610014	38.4		33	33	28	26		33	32	27	25		33	31	29	25	24
Cincinnati - Taft Ave	Hamilton	390610040	36.7		31	30	26	24		31	30	26	24		32	29	26	24	23
Cincinnati - 8th Ave	Hamilton	390610042	37.3		32	32	30	28		32	31	29	28		33	31	29	28	27
Sharonville	Hamilton	390610043	36.0		32	31	30	28		32	31	29	28		32	31	29	28	27
Norwood	Hamilton	390617001	38.8		34	33	32	30		33	33	31	30		34	33	31	30	29
St. Bernard	Hamilton	390618001	40.6		35	35	32	30		35	34	31	30		35	33	32	31	29
Steubenville	Jefferson	390810016	40.7		**36**	35	32	29		35	34	30	28		**37**	35	31	29	28
Mingo Junction	Jefferson	390811001	42.0		**37**	**37**	33	30		**37**	**36**	32	30		**38**	**36**	32	30	30
Dayton	Montgomery	391130032	37.8		34	33	31	30		33	33	31	30		34	33	31	31	30
Canton - Dueber	Stark	391510017	38.6		33	32	30	28		33	31	30	28		33	30	29	28	27
Akron - Brittain	Summit	391530017	38.1		33	33	31	30		33	32	31	30		33	32	30	29	29
Wisconsin																			
Green Bay - Est High	Brown	550090005	37.1		35	34	35	35		34	35	35	34		33	33	33	32	32
Madison	Dane	550250047	36.4		33	33	32	32		33	32	32	31		32	31	30	29	29
Milwaukee-Health Center	Milwaukee	550790010	38.7		35	35	35	35		35	35	35	34		35	34	34	34	33
Milwaukee-SER Hdqs	Milwaukee	550790026	37.4		34	34	34	34		34	34	34	34		34	34	34	34	33
Milwaukee-Virginia FS	Milwaukee	550790043	39.9		**37**	**37**	**37**	**36**		**37**	**36**	**37**	**36**		**36**	**36**	**37**	**36**	**36**
Milwaukee- Fire Dept Hdqs	Milwaukee	550790099	37.8		34	34	33	33		34	33	33	32		34	33	33	33	32
Waukesha	Waukesha	551330027	35.5		32	32	32	31		32	32	32	31		32	31	31	30	29

Table 3. Modeling Results: Number of Sites > NAAQS

Ozone (85 ppb)		Round 5 without CAIR				Round 5 w/ CAIR
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	0	0	0	0	----	0
IN	0	0	0	0	----	0
MI	3	1	1	1	----	1
OH	4	0	0	0	----	0
WI	2	0	0	0	----	0
Total	**9**	**1**	**1**	**1**		**1**
2012						
IL	0	0	0	0	----	0
IN	0	0	0	0	----	0
MI	3	0	0	0	----	0
OH	4	0	0	0	----	0
WI	2	0	0	0	----	0
Total	**9**	**0**	**0**	**0**		**0**
2018						
IL	0	0	0	0	0	0
IN	0	0	0	0	0	0
MI	3	0	0	0	0	0
OH	4	0	0	0	0	0
WI	2	0	0	0	0	0
Total	**9**	**0**	**0**	**0**	**0**	**0**
Ozone (75 ppb)		**Round 5 without CAIR**				**Round5 w/ CAIR**
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	12	6	6	6	----	4
IN	26	10	9	8	----	5
MI	21	12	12	12	----	12
OH	45	27	25	24	----	21
WI	12	10	10	10	----	10
Total	**116**	**65**	**62**	**60**	**----**	**52**
2012						
IL	12	3	3	3	----	1
IN	26	5	4	4	----	3
MI	21	9	8	8	----	6
OH	45	18	14	12	----	11
WI	12	10	9	9	----	9
Total	**116**	**45**	**38**	**36**		**30**
2018						
IL	12	0	0	0	0	0
IN	26	0	0	0	0	0
MI	21	3	3	3	3	3
OH	45	3	3	2	1	1
WI	12	3	2	1	1	1
Total	**116**	**9**	**8**	**6**	**5**	**5**

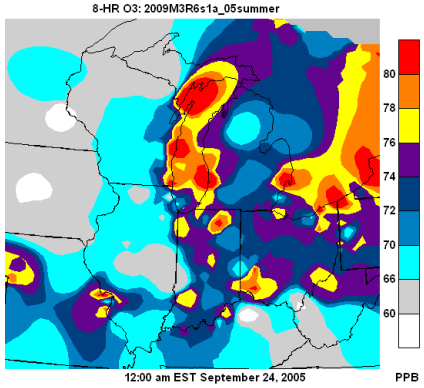
PM2.5 - Annual		Round 5 without CAIR				Round 5 w/ CAIR
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	7	4	4	1	----	1
IN	6	2	2	0	----	0
MI	2	2	2	1	----	1
OH	26	13	12	5	----	1
WI	0	0	0	0	----	0
Total	**41**	**21**	**20**	**7**		**3**
2012						
IL	7	3	1	1	----	0
IN	6	1	1	0	----	0
MI	2	2	1	1	----	1
OH	26	12	9	4	----	0
WI	0	0	0	0	----	0
Total	**41**	**18**	**12**	**6**		**1**
2018						
IL	7	3	1	0	0	0
IN	6	1	1	0	0	0
MI	2	2	1	1	1	1
OH	26	13	8	2	0	0
WI	0	0	0	0	0	0
Total	**41**	**19**	**11**	**3**	**1**	**1**
PM2.5 - Daily						
		Round 5 without CAIR				**Round 5 w/ CAIR**
2009	**Baseyear**	**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
IL	16	7	7	6	----	6
IN	13	0	0	0	----	0
MI	14	10	9	9	----	5
OH	31	4	3	2	----	2
WI	8	1	1	1	----	1
Total	**82**	**22**	**20**	**18**	**----**	**14**
2012						
IL	16	9	6	8	----	6
IN	13	0	0	0	----	0
MI	14	8	6	6	----	5
OH	31	3	3	2	----	1
WI	8	1	1	1	----	1
Total	**82**	**21**	**16**	**17**		**13**
2018						
IL	16	10	6	8	8	5
IN	13	4	1	1	0	0
MI	14	8	6	6	5	4
OH	31	5	3	2	1	0
WI	8	1	1	1	1	1
Total	**82**	**28**	**17**	**18**	**15**	**10**

Table 4. Modeling Results: Future Year Visibility Levels

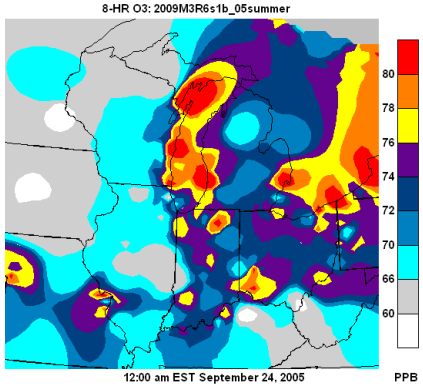
Worst 20%				2018				
				Round 5 without CAIR				Round 5 w/ CAIR
Site	Baseline (2000-2004)	2018 URP		Scen. A	Scen. B	Scen. C	Scen. C-BART	
BOWA1	19.86	17.94		19.09	18.87	18.54	18.02	17.94
VOYA2	19.48	17.75		18.60	18.44	18.17	17.77	17.63
SENE1	24.38	21.64		24.02	23.58	23.03	22.38	22.59
ISLE1	21.59	19.43		21.05	20.86	20.62	20.22	20.09
ISLE9	21.59	19.43		20.83	20.58	20.38	19.84	19.84
HEGL1	26.75	23.13		26.24	25.83	24.87	24.23	24.22
MING1	28.15	24.27		27.51	26.98	25.81	24.93	24.74
CACR1	26.36	22.91		25.32	24.80	23.57	22.97	22.44
UPBU1	26.27	22.82		25.31	24.79	23.50	22.79	22.59
MACA1	31.37	26.64		30.11	29.08	27.06	26.24	26.10
DOSO1	29.05	24.69		27.88	26.96	24.36	23.74	23.00
SHEN1	29.31	25.12		28.38	27.65	25.24	24.69	23.92
JARI1	29.12	24.91		28.06	27.21	25.00	24.48	24.06
BRIG1	29.01	25.05		28.10	28.07	26.57	26.25	25.21
LYBR1	24.45	21.48		24.06	23.86	22.58	22.30	21.14
ACAD1	22.89	20.45		22.88	22.76	22.31	22.16	21.49
Best 20%				**2018**				
				Round 5 without CAIR				**Round 5 w/ CAIR**
Site	**Baseline (2000-2004)**	**2018 Max**		**Scen. A**	**Scen. B**	**Scen. C**	**Scen. C-BART**	
BOWA1	6.42	6.42		6.20	6.17	6.16	6.12	6.14
VOYA2	7.09	7.09		6.87	6.83	6.81	6.78	6.75
SENE1	7.14	7.14		7.80	7.78	7.81	7.77	7.71
ISLE1	6.75	6.75		6.77	6.76	6.72	6.67	6.60
ISLE9	6.75	6.75		6.63	6.61	6.58	6.53	6.52
HEGL1	12.84	12.84		12.17	12.20	12.07	11.63	11.66
MING1	14.46	14.46		13.78	13.77	13.70	13.37	13.28
CACR1	11.24	11.24		10.94	10.99	10.97	10.78	10.52
UPBU1	11.71	11.71		11.18	11.23	11.18	10.96	10.73
MACA1	16.51	16.51		16.32	16.21	15.76	15.34	15.25
DOSO1	12.28	12.28		12.02	11.84	11.27	11.03	11.00
SHEN1	10.93	10.93		10.98	10.91	10.25	10.16	9.91
JARI1	14.21	14.21		14.19	13.98	13.42	13.21	13.14
BRIG1	14.33	14.33		14.32	14.46	14.22	14.17	13.92
LYBR1	6.37	6.37		6.39	6.38	6.31	6.28	6.14
ACAD1	8.78	8.78		8.97	8.96	8.90	8.89	8.82

Figure 2. Ozone Modeling Results

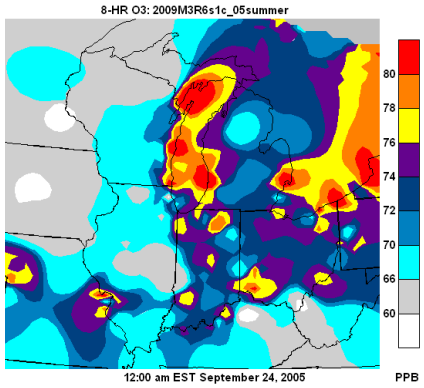
2009 Round 5 – Scen. A



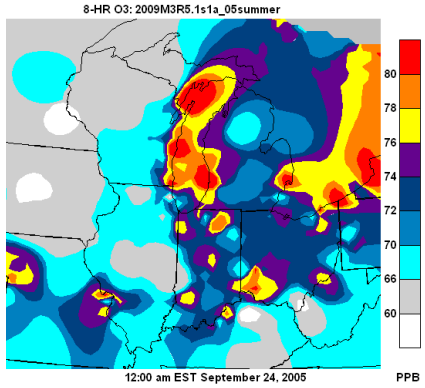
Round 5 – Scen. B



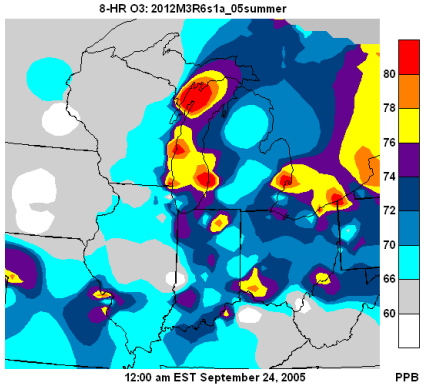
Round 5 – Scen. C



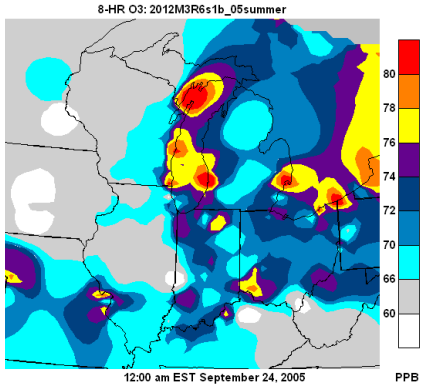
Round 5 - CAIR



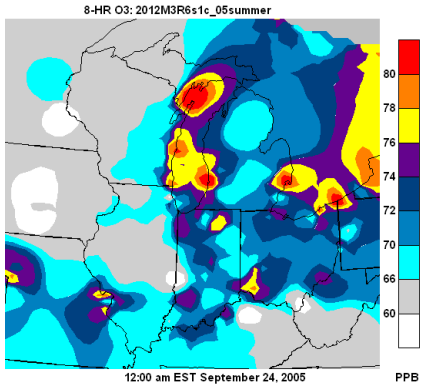
2012 Round 5 – Scen. A



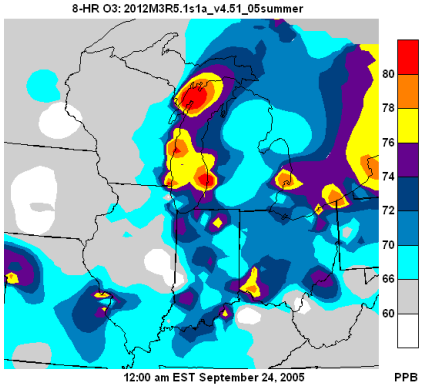
Round 5 – Scen. B



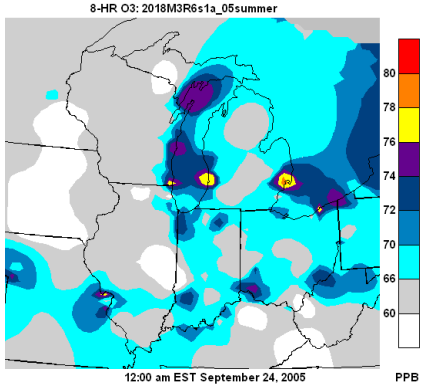
Round 5 – Scen. C



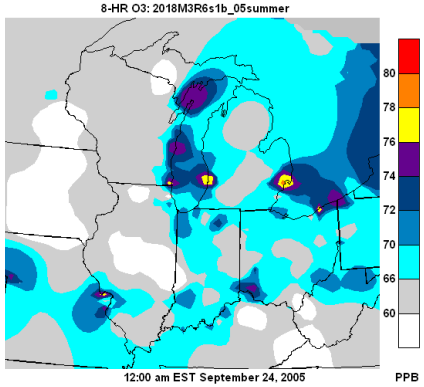
Round 5 - CAIR



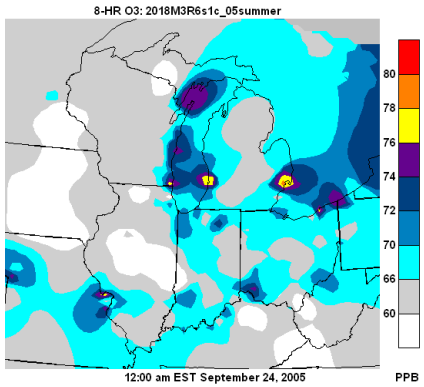
2018 Round 5 – Scen. A



Round 5 – Scen. B



Round 5 – Scen. C



Round 5 - CAIR

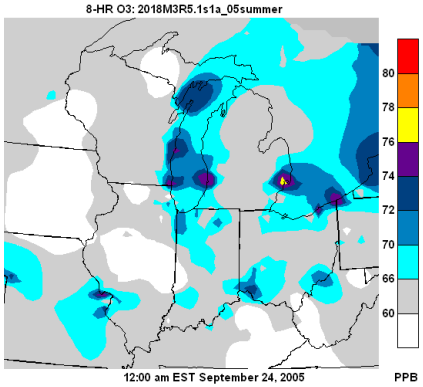


Figure 3. PM2.5 Annual Modeling Results

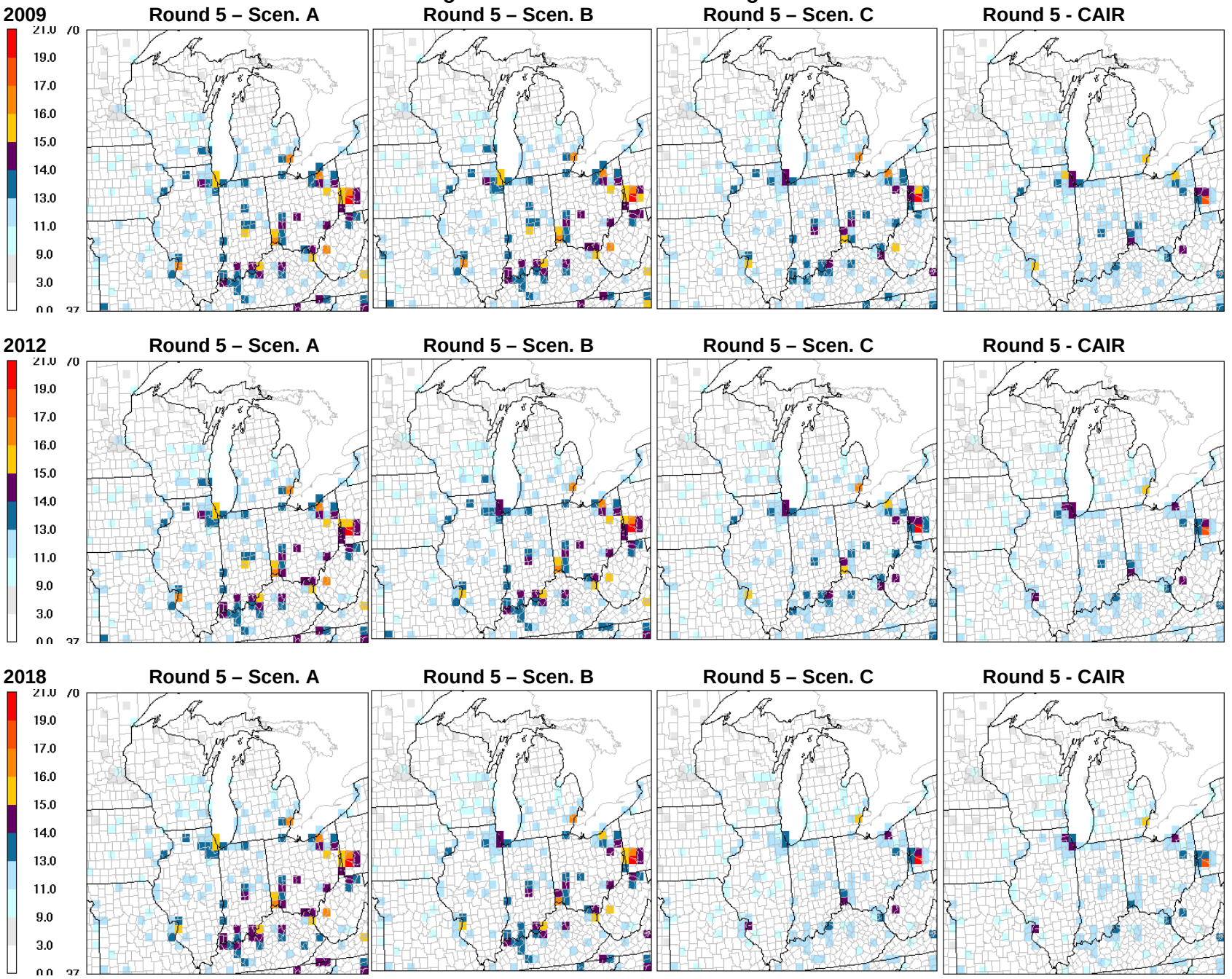
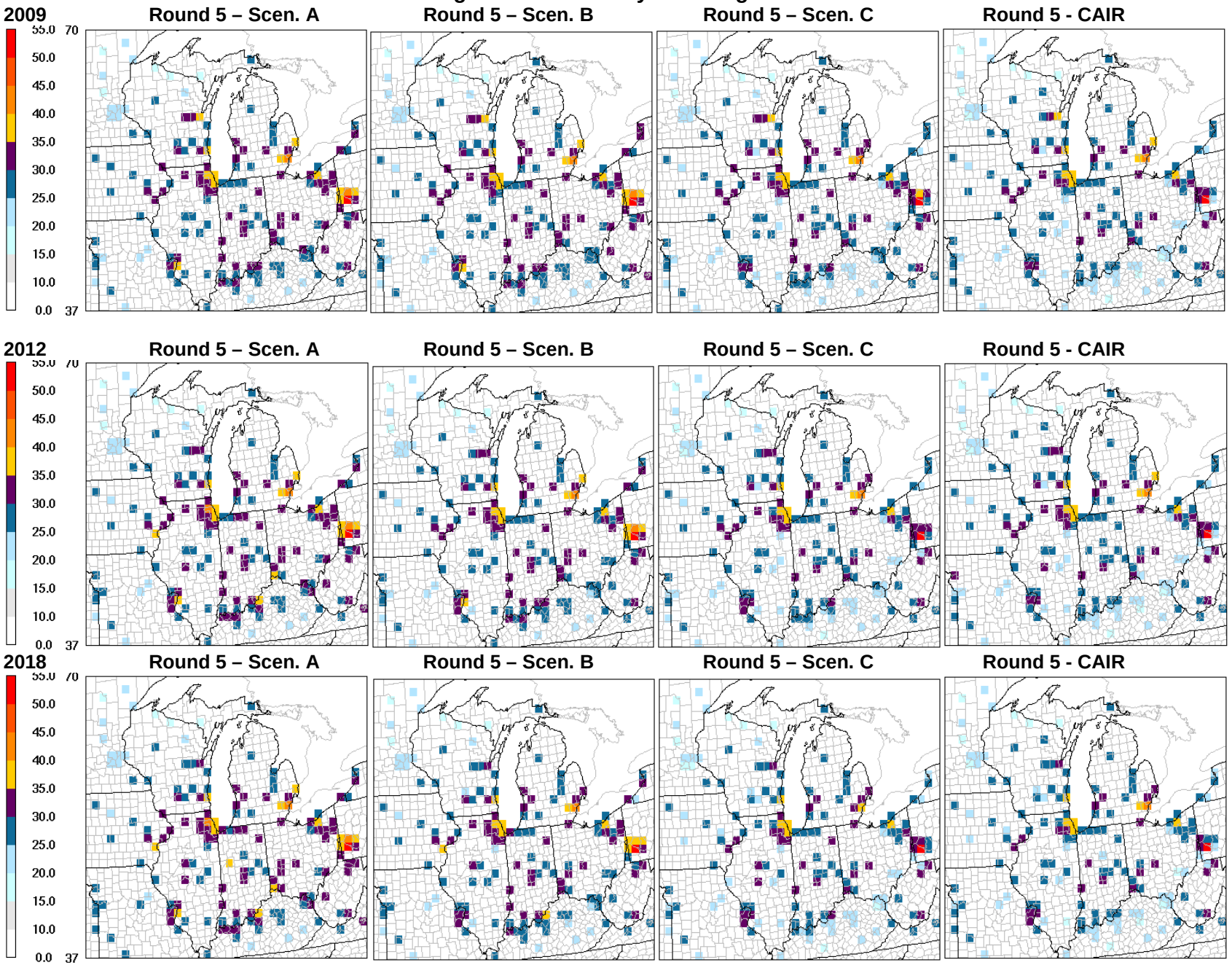


Figure 4. PM2.5 Daily Modeling Results



Appendix I

Scenario B (Legally Enforceable) Controls

NOx – 2009

Point Source Grown and Controlled Emissions by facility for NOX r6s1b_2009 Base Year = 2002

Future Year = 2009

STID=17 CYID=57 fcid=057801AAA name=AES DUCK CREEK

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	57	057801AAA	0001	0001	01	10100202	NOX	0.8147	0.8416	0.8416	0.00	0.00	SCR	SCR added by LADCO

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0001	0001	01	10100202	NOX	3.0515	3.1522	3.1522	0.00	0.00	lnb	LNB added by LADCO
17	143	143805AAG	0001	0003	01	10100202	NOX	6.9419	7.1708	7.1708	0.00	0.00	lnb	LNB added by LADCO
17	143	143805AAG	0002	0004	01	10100202	NOX	2.1310	2.2013	2.2013	0.00	0.00	lnb	LNB added by LADCO
----								--------	--------	----------				
fcid								12.1244	12.5243	12.5243				
cyid								12.1244	12.5243	12.5243				
stid								12.9392	13.3659	13.3659				

STID=39 CYID=1 fcid=0701000007 name="DP&L, J.M. STUART GENERATING STATION"

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	1	0701000007	R1	B001	B001P1	10100202	NOX	6.9860	6.9756	2.3252	0.85	0.95	SCR	SCR added by LADCO
39	1	0701000007	R2	B002	B002P1	10100202	NOX	3.6327	3.6273	1.2091	0.85	0.95	SCR	SCR added by LADCO
39	1	0701000007	R3	B003	B003P1	10100202	NOX	5.0133	5.0058	1.6686	0.85	0.95	SCR	SCR added by LADCO
39	1	0701000007	R4	B004	B004P1	10100202	NOX	7.8493	7.8376	2.6125	0.85	0.95	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								23.4814	23.4464	7.8155				
cyid								23.4814	23.4464	7.8155				

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	167	0684000000	R1	B001	B001P1	10200501	NOX	0.0017	0.0017	0.0001	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P1	10100201	NOX	5.8167	5.8080	0.2904	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	NOX	7.9017	7.8899	0.3945	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	NOX	7.8775	7.8657	0.3933	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	NOX	3.8586	3.8528	0.1926	0.00	0.95	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	NOX	0.0000	0.0000	0.0000	0.00	0.95	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								25.4561	25.4182	1.2709				
cyid								25.4561	25.4182	1.2709				
stid								48.9375	48.8646	9.0864				

STID=55 CYID=79 fcid=241007800 name=WIS ELECTRIC POWER VALLEY STATION

Base Yr	Grown	Controlled	Base Year	Future Year

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007800	S11	B21	01	10100202	NOX	2.7972	2.8895	1.6470	0.00	0.43	SCR	SCR added by LADCO
55	79	241007800	S11	B22	01	10100202	NOX	2.9073	3.0032	1.7118	0.00	0.43	SCR	SCR added by LADCO
55	79	241007800	S12	B23	01	10100202	NOX	2.3270	2.4038	1.2740	0.00	0.47	SCR	SCR added by LADCO
55	79	241007800	S12	B24	01	10100202	NOX	2.3427	2.4199	1.2826	0.00	0.47	SCR	Scrubber added by LADCO
----								--------	--------	----------				
fcid								10.3742	10.7164	5.9154				
cyid								10.3742	10.7164	5.9154				

STID=55 CYID=117 fcid=460033090 name=WP & L Alliant Energy - Edgewater Gen Station

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
55	117	460033090	S11	B23	01	10100203	NOX	1.6197	1.6731	1.0038	0.00	0.40	SCR	SCR added by LADCO
55	117	460033090	S11	B24	01	10100203	NOX	4.1072	4.2426	3.4789	0.00	0.18	SCR	SCR added by LADCO
55	117	460033090	S12	B25	01	10100221	NOX	5.6804	5.8677	4.9876	0.00	0.15	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								11.4072	11.7834	9.4703				
cyid								11.4072	11.7834	9.4703				
stid								21.7814	22.4997	15.3857				
								========	========	==========				
								83.6581	84.7302	37.8380				

NOx - 2012

Point Source Grown and Controlled Emissions by facility for NOX r6s1b_2012 Base Year = 2002

Future Year = 2012

STID=17 CYID=33 fcid=033801AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	33	033801AAA	0005	0005	01	10100202	NOX	1.642	1.871	0.9357	0.00	0.500	SCR	SCR added by LADCO
17	33	033801AAA	0006	0006	01	10100202	NOX	2.116	2.413	1.2063	0.00	0.500	SCR	SCR added by LADCO
---								--------	--------	----------				
fcid								3.758	4.284	2.1420				
cyid								3.758	4.284	2.1420				

STID=17 CYID=57 fcid=057801AAA name=AES DUCK CREEK

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	57	057801AAA	0001	0001	01	10100202	NOX	0.815	0.929	0.9288	0.00	0.000	SCR	SCR added by LADCO

STID=17 CYID=79 fcid=079808AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	79	079808AAA	0003	0003	01	10100202	NOX	6.735	7.678	7.6780	0.00	0.000	SCR	SCR added by LADCO
17	79	079808AAA	0012	0013	01	10100501	NOX	5.936	5.378	5.3781	0.00	0.000	SCR	SCR added by LADCO
---								--------	--------	----------				
fcid								12.671	13.056	13.0561				
cyid								12.671	13.056	13.0561				

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0016	0031	02	10100401	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO

STID=17 CYID=137 fcid=137805AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	137	137805AAA	0003	0003	01	10100202	NOX	5.356	6.106	6.1058	0.00	0.000	LNB	LNB added by LADCO

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0001	0001	01	10100202	NOX	3.052	3.479	3.4789	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0001	0003	01	10100202	NOX	6.942	7.914	7.9141	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0002	0004	01	10100202	NOX	2.131	2.429	2.4294	0.00	0.000	lnb	LNB added by LADCO
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fcid								12.124	13.822	13.8224				
cyid								12.124	13.822	13.8224				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	NOX	6.527	7.441	0.0074	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
17	167	167120AAO	0010	0013	01	10100203	NOX	2.646	3.017	0.0030	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
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fcid								9.173	10.458	0.0105				
cyid								9.173	10.458	0.0105				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	NOX	22.429	25.570	1.2785	0.00	0.950	SCR	SCR added by LADCO
17	179	179801AAA	0018	0031	01	10100203	NOX	38.993	44.454	2.2227	0.00	0.950	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								61.422	70.024	3.5012				
cyid								61.422	70.024	3.5012				

STID=17 CYID=197 fcid=197809AAO name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197809AAO	0032	0033	02	10100604	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197810AAK	0011	0016	02	10100222	NOX	5.731	6.534	3.9203	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0011	0016	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0013	0010	02	10100223	NOX	8.598	9.802	0.0098	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0013	0010	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	02	10100223	NOX	10.974	12.511	0.0125	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
----								--------	--------	----------				
fcid								25.303	28.847	3.9426				
cyid								25.303	28.847	3.9426				
stid								130.622	147.527	43.5096				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	NOX	13.661	14.142	2.8284	0.00	0.800	SCR	SCR added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO
----								--------	--------	----------				
fcid								13.661	14.142	2.8284				
cyid								13.661	14.142	2.8284				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

27	109	2710900011	SV003	EU004	001	10100202	NOX	2.079	2.152	1.2911	0.00	0.400	SNCR	SCR added by LADCO
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stid								15.739	16.294	4.1195				

STID=39 CYID=1 fcid=0701000007 name="DP&L, J.M. STUART GENERATING STATION"

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	1	0701000007	R1	B001	B001P1	10100202	NOX	6.986	7.296	2.4319	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R2	B002	B002P1	10100202	NOX	3.633	3.794	1.2646	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R3	B003	B003P1	10100202	NOX	5.013	5.235	1.7452	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R4	B004	B004P1	10100202	NOX	7.849	8.197	2.7324	0.85	0.950	SCR	SCR added by LADCO
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fcid								23.481	24.522	8.1740				
cyid								23.481	24.522	8.1740				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	NOX	20.852	21.776	1.0888	0.00	0.950	SCR	SCR added by LADCO

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	167	0684000000	R1	B001	B001P1	10200501	NOX	0.002	0.002	0.0001	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P1	10100201	NOX	5.817	6.074	0.3037	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	NOX	7.902	8.252	0.4126	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	NOX	7.877	8.227	0.4113	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	NOX	3.859	4.030	0.2015	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
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fcid								25.456	26.584	1.3292				
cyid								25.456	26.584	1.3292				
stid								69.789	72.882	10.5920				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	NOX	4.755	5.421	3.0898	0.00	0.430	SCR	SCR added by LADCO
55	79	241007690	S13	B26	01	10100202	NOX	3.277	3.736	2.2045	0.00	0.410	SCR	SCR added by LADCO
55	79	241007690	S14	B27	01	10100212	NOX	3.333	3.800	2.8499	0.00	0.250	SCR	SCR added by LADCO
55	79	241007690	S14	B28	01	10100212	NOX	3.384	3.857	2.9316	0.00	0.240	SCR	SCR added by LADCO
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fcid								14.749	16.814	11.0757				

STID=55 CYID=79 fcid=241007800 name=WIS ELECTRIC POWER VALLEY STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Grown Tons/Day	Controlled Base Year Tons/Day	Future Year Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007800	S11	B21	01	10100202	NOX	2.797	3.189	1.8177	0.00	0.430	SCR	SCR added by LADCO
55	79	241007800	S11	B22	01	10100202	NOX	2.907	3.314	1.8893	0.00	0.430	SCR	SCR added by LADCO
55	79	241007800	S12	B23	01	10100202	NOX	2.327	2.653	1.4061	0.00	0.470	SCR	SCR added by LADCO
55	79	241007800	S12	B24	01	10100202	NOX	2.343	2.671	1.4155	0.00	0.470	SCR	Scrubber added by LADCO
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fcid								10.374	11.827	6.5285				
cyid								25.123	28.641	17.6042				

STID=55 CYID=117 fcid=460033090 name=WP & L Alliant Energy - Edgewater Gen Station

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Grown Tons/Day	Controlled Base Year Tons/Day	Future Year Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	117	460033090	S11	B23	01	10100203	NOX	1.620	1.846	1.1079	0.00	0.400	SCR	SCR added by LADCO
55	117	460033090	S11	B24	01	10100203	NOX	4.107	4.682	3.8395	0.00	0.180	SCR	SCR added by LADCO
55	117	460033090	S12	B25	01	10100221	NOX	5.680	6.476	5.5045	0.00	0.150	SCR	SCR added by LADCO
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fcid								11.407	13.005	10.4519				
cyid								11.407	13.005	10.4519				
stid								36.530	41.646	28.0562				
								========	========	==========				
								252.681	278.349	86.2773				

NOx 2018

Point Source Grown and Controlled Emissions by facility for NOX r6s1b_2018 Base Year = 2002

Future Year = 2018

STID=17 CYID=31 fcid=031600AIN name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AIN	0010	0013	01	10100226	NOX	2.283	2.592	1.5550	0.00	0.400	SCR	SCR added by LADCO
17	31	031600AIN	0010	0013	02	10100601	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
17	31	031600AIN	0012	0016	01	10100226	NOX	3.991	4.531	2.7184	0.00	0.400	SCR	SCR added by LADCO
17	31	031600AIN	0012	0016	02	10100601	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
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fcid								6.274	7.122	4.2734				
cyid								6.274	7.122	4.2734				

STID=17 CYID=33 fcid=033801AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	33	033801AAA	0005	0005	01	10100202	NOX	1.642	1.863	0.9317	0.00	0.500	SCR	SCR added by LADCO
17	33	033801AAA	0006	0006	01	10100202	NOX	2.116	2.402	1.2012	0.00	0.500	SCR	SCR added by LADCO
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fcid								3.758	4.266	2.1329				
cyid								3.758	4.266	2.1329				

STID=17 CYID=57 fcid=057801AAA name=AES DUCK CREEK

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	57	057801AAA	0001	0001	01	10100202	NOX	0.815	0.925	0.9249	0.00	0.000	SCR	SCR added by LADCO

STID=17 CYID=79 fcid=079808AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	79	079808AAA	0003	0003	01	10100202	NOX	6.735	7.645	7.6453	0.00	0.000	SCR	SCR added by LADCO
17	79	079808AAA	0012	0013	01	10100501	NOX	5.936	3.984	3.9838	0.00	0.000	SCR	SCR added by LADCO
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fcid								12.671	11.629	11.6291				
cyid								12.671	11.629	11.6291				

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0016	0031	02	10100401	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO

STID=17 CYID=137 fcid=137805AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	137	137805AAA	0003	0003	01	10100202	NOX	5.356	6.080	6.0798	0.00	0.000	LNB	LNB added by LADCO

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0001	0001	01	10100202	NOX	3.052	3.464	3.4641	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0001	0003	01	10100202	NOX	6.942	7.880	7.8804	0.00	0.000	lnb	LNB added by LADCO
17	143	143805AAG	0002	0004	01	10100202	NOX	2.131	2.419	2.4191	0.00	0.000	lnb	LNB added by LADCO
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fcid								12.124	13.764	13.7636				
cyid								12.124	13.764	13.7636				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	NOX	6.527	7.410	0.0074	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
17	167	167120AAO	0010	0013	01	10100203	NOX	2.646	3.004	0.0030	0.00	0.999	SHUTDOWN	SHUTDOWN added by LADCO
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fcid								9.173	10.414	0.0104				
cyid								9.173	10.414	0.0104				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	NOX	22.429	25.462	1.2731	0.00	0.950	SCR	SCR added by LADCO
17	179	179801AAA	0018	0031	01	10100203	NOX	38.993	44.265	2.2132	0.00	0.950	SCR	SCR added by LADCO
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fcid								61.422	69.726	3.4863				
cyid								61.422	69.726	3.4863				

STID=17 CYID=197 fcid=197809AAO name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197809AAO	0032	0033	02	10100604	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197810AAK	0011	0016	02	10100222	NOX	5.731	6.506	3.9036	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0011	0016	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.400	SCR	SCR added by LADCO
17	197	197810AAK	0013	0010	02	10100223	NOX	8.598	9.760	0.0098	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0013	0010	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	02	10100223	NOX	10.974	12.458	0.0125	0.00	0.999	SHUTDOWN	SCR added by LADCO
17	197	197810AAK	0007	0012	03	10100501	NOX	0.000	0.000	0.0000	0.00	0.999	SHUTDOWN	SCR added by LADCO
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fcid								25.303	28.724	3.9258				
cyid								25.303	28.724	3.9258				
stid								136.896	152.649	46.2263				

STID=18 CYID=147 fcid=00020 name=INDIANA MICHIGAN POWER-ROCKPORT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
18	147	00020	1	001	01	10100222	NOX	23.226	25.291	1.2646	0.00	0.950	SCR	SCR added by LADCO
18	147	00020	1	001	02	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
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fcid								23.226	25.291	1.2646				
cyid								23.226	25.291	1.2646				
stid								23.226	25.291	1.2646				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	NOX	13.661	15.733	3.1466	0.00	0.800	SCR	SCR added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	NOX	0.000	0.000	0.0000	0.00	0.800	SCR	SCR added by LADCO
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fcid								13.661	15.733	3.1466				
cyid								13.661	15.733	3.1466				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	109	2710900011	SV003	EU004	001	10100202	NOX	2.079	2.394	1.4363	0.00	0.400	SNCR	SCR added by LADCO
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stid								15.739	18.127	4.5830				

STID=39 CYID=1 fcid=0701000007 name="DP&L, J.M. STUART GENERATING STATION"

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	1	0701000007	R1	B001	B001P1	10100202	NOX	6.986	7.607	2.5358	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R2	B002	B002P1	10100202	NOX	3.633	3.956	1.3186	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R3	B003	B003P1	10100202	NOX	5.013	5.459	1.8197	0.85	0.950	SCR	SCR added by LADCO
39	1	0701000007	R4	B004	B004P1	10100202	NOX	7.849	8.547	2.8491	0.85	0.950	SCR	SCR added by LADCO
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fcid								23.481	25.570	8.5232				
cyid								23.481	25.570	8.5232				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	NOX	20.852	22.706	1.1353	0.00	0.950	SCR	SCR added by LADCO

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Future Year Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	167	0684000000	R1	B001	B001P1	10200501	NOX	0.002	0.002	0.0001	0.00	0.950	SCR	SCR added by LADCO

39	167	0684000000	R2	B002	B002P1	10100201	NOX	5.817	6.334	0.3167	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	NOX	7.902	8.604	0.4302	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	NOX	7.877	8.578	0.4289	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	NOX	3.859	4.202	0.2101	0.00	0.950	SCR	SCR added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	NOX	0.000	0.000	0.0000	0.00	0.950	SCR	SCR added by LADCO
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fcid								25.456	27.720	1.3860				
cyid								25.456	27.720	1.3860				
stid								69.789	75.996	11.0445				

STID=54 CYID=39 fcid=0006 name=APPALACHIAN POWER - KANAWHA RIVER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	39	0006	012	001	99	10100202	NOX	4.829	5.258	2.6291	0.00	0.500	SCR	Scrubber added by LADCO
54	39	0006	012	002	99	10100202	NOX	4.921	5.359	2.6794	0.00	0.500	SCR	Scrubber added by LADCO
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fcid								9.750	10.617	5.3085				
cyid								9.750	10.617	5.3085				
stid								9.750	10.617	5.3085				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	NOX	4.755	5.398	3.0766	0.00	0.430	SCR	SCR added by LADCO
55	79	241007690	S13	B26	01	10100202	NOX	3.277	3.720	2.1951	0.00	0.410	SCR	SCR added by LADCO
55	79	241007690	S14	B27	01	10100212	NOX	3.333	3.784	2.8378	0.00	0.250	SCR	SCR added by LADCO
55	79	241007690	S14	B28	01	10100212	NOX	3.384	3.841	2.9191	0.00	0.240	SCR	SCR added by LADCO
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fcid								14.749	16.743	11.0285				

STID=55 CYID=79 fcid=241007800 name=WIS ELECTRIC POWER VALLEY STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007800	S11	B21	01	10100202	NOX	2.797	3.175	1.4289	0.00	0.550	SCR	SCR added by LADCO
55	79	241007800	S11	B22	01	10100202	NOX	2.907	3.300	1.4852	0.00	0.550	SCR	SCR added by LADCO
55	79	241007800	S12	B23	01	10100202	NOX	2.327	2.642	1.1887	0.00	0.550	SCR	SCR added by LADCO
55	79	241007800	S12	B24	01	10100202	NOX	2.343	2.659	1.1967	0.00	0.550	SCR	SCR added by LADCO
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fcid								10.374	11.777	5.2995				
cyid								25.123	28.519	16.3281				

STID=55 CYID=117 fcid=460033090 name=WP & L Alliant Energy - Edgewater Gen Station

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	117	460033090	S11	B23	01	10100203	NOX	1.620	1.839	1.1032	0.00	0.400	SCR	SCR added by LADCO

55	117	460033090	S11	B24	01	10100203	NOX	4.107	4.662	3.8232	0.00	0.180	SCR	SCR added by LADCO
55	117	460033090	S12	B25	01	10100221	NOX	5.680	6.448	5.4811	0.00	0.150	SCR	SCR added by LADCO
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fcid						11.407	12.949	10.4074						
cyid						11.407	12.949	10.4074						
stid						36.530	41.469	26.7355						
						========	========	==========						
						291.931	324.149	95.1624						

SO2 – 2009

Point Source Grown and Controlled Emissions by facility for SO2 r6s1b_2009

Base Year = 2002

Future Year = 2009

STID=19 CYID=115 fcid=58-07-001 name=MIDAMERICAN ENERGY CO. - LOUISA STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
19	115	58-07-001	117487	147281	99	10100222	SO2	33.664	34.774	3.4774	0.0	0.90	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=161 fcid=2116100009 name=EAST KY POWER COOP

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
21	161	2116100009	1	001	99	10100202	SO2	42.166	42.103	4.2103	0.0	0.90	SCRUBBER	Scrubber added by LADCO
21	161	2116100009	2	002	99	10100212	SO2	55.385	55.303	5.5303	0.0	0.90	SCRUBBER	Scrubber added by LADCO
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fcid								97.551	97.406	9.7406				
cyid								97.551	97.406	9.7406				
stid								97.551	97.406	9.7406				

STID=27 CYID=141 fcid=2714100004 name=NSP - Sherburne Generating Plant

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	141	2714100004	SV001	EU001	001	10100222	SO2	16.765	16.987	3.6401	0.3	0.85	SCRUBBER	Scrubber added by LADCO
27	141	2714100004	SV001	EU002	001	10100222	SO2	22.549	22.848	4.8959	0.3	0.85	SCRUBBER	Scrubber added by LADCO
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fcid								39.314	39.834	8.5360				
cyid								39.314	39.834	8.5360				
stid								39.314	39.834	8.5360				

STID=54 CYID=51 fcid=0005 name=OHIO POWER - MITCHELL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0005	012	001	99	10100202	SO2	17.775	17.748	1.7748	0.0	0.90	SCRUBBER	Scrubber added by LADCO
54	51	0005	012	002	99	10100202	SO2	5.689	5.680	0.5680	0.0	0.90	SCRUBBER	Scrubber added by LADCO
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fcid								23.463	23.428	2.3428				
cyid								23.463	23.428	2.3428				

STID=54 CYID=53 fcid=0009 name=APPALACHIAN POWER - MOUNTAINEER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	53	0009	001	001	99	10100202	SO2	11.196	11.179	1.1179	0.0	0.90	SCRUBBER	Scrubber added by LADCO

STID=54 CYID=79 fcid=0006 name=APPALACHIAN POWER - JOHN E AMOS PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

54	79	0006	012	001	99	10100202	SO2	79.635	79.516	7.9516	0.0	0.90	SCRUBBER Scrubber added by LADCO
54	79	0006	003	003	99	10100202	SO2	139.377	139.169	13.9169	0.0	0.90	SCRUBBER Scrubber added by LADCO

fcid	219.012	218.685	21.8685
cyid	219.012	218.685	21.8685
stid	253.671	253.293	25.3293
	424.200	425.307	47.0832

SO2 – 2012

Point Source Grown and Controlled Emissions by facility for SO2 r6s1b_2012

Base Year = 2002

Future Year = 2012

STID=17 CYID=31 fcid=031600AMI name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AMI	0007	0010	01	10100226	SO2	16.13	18.39	1.839	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0018	0033	01	10100226	SO2	24.14	27.52	2.752	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0021	0036	01	10100226	SO2	19.23	21.92	2.192	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0016	0031	01	10100203	SO2	4.59	5.24	0.005	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								47.96	54.68	4.950				
cyid								47.96	54.68	4.950				

STID=17 CYID=125 fcid=125804AAB name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	125	125804AAB	0019	0023	01	10100202	SO2	22.34	25.47	3.821	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=127 fcid=127855AAC name=ELECTRIC ENERGY INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	127	127855AAC	0001	0001	01	10100222	SO2	11.83	13.48	13.482	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0001	0002	01	10100222	SO2	11.48	13.09	13.085	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0002	0003	01	10100222	SO2	10.25	11.68	11.680	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0002	0004	01	10100222	SO2	12.04	13.73	13.731	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0003	0006	01	10100222	SO2	12.68	14.46	14.456	0.0	0.000	LNB	LNB added by LADCO
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fcid								58.27	66.43	66.435				
cyid								58.27	66.43	66.435				

STID=17 CYID=135 fcid=135803AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	135	135803AAA	0001	0001	01	10100203	SO2	32.99	37.61	3.761	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	135	135803AAA	0001	0003	01	10100203	SO2	72.92	83.13	8.313	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								105.91	120.74	12.074				
cyid								105.91	120.74	12.074				

STID=17 CYID=157 fcid=157851AAA name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	157	157851AAA	0001	0001	01	10100203	SO2	25.14	28.66	4.299	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0002	0002	01	10100203	SO2	25.79	29.41	4.411	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0013	0013	01	10100202	SO2	27.79	31.68	4.752	0.0	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								78.72	89.75	13.462				
cyid								78.72	89.75	13.462				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	SO2	44.20	50.39	0.050	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	167	167120AAO	0010	0013	01	10100203	SO2	16.40	18.70	0.019	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								60.61	69.10	0.069				
cyid								60.61	69.10	0.069				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	SO2	25.35	28.90	2.890	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	179	179801AAA	0018	0031	01	10100203	SO2	41.57	47.39	4.739	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.91	76.29	7.629				
cyid								66.91	76.29	7.629				

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	197	197810AAK	0013	0010	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	02	10100223	SO2	15.33	17.48	0.017	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								15.33	17.48	0.017				
cyid								15.33	17.48	0.017				
stid								472.19	538.32	110.295				

STID=19 CYID=115 fcid=58-07-001 name=MIDAMERICAN ENERGY CO. - LOUISA STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
19	115	58-07-001	117487	147281	99	10100222	SO2	33.66	38.38	3.838	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=161 fcid=2116100009 name=EAST KY POWER COOP

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

21	161	2116100009	1	001	99	10100202	SO2	42.17	44.03	4.403	0.0	0.900	SCRUBBER	Scrubber added by LADCO
21	161	2116100009	2	002	99	10100212	SO2	55.39	57.84	5.784	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								97.55	101.87	10.187				
cyid								97.55	101.87	10.187				
stid								97.55	101.87	10.187				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	SO2	33.99	35.19	15.081	0.3	0.700	SCRUBBER	Scrubber added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	SO2	0.00	0.00	0.000	0.3	0.700	SCRUBBER	Scrubber added by LADCO
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fcid								33.99	35.19	15.081				
cyid								33.99	35.19	15.081				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	109	2710900011	SV003	EU004	001	10100202	SO2	7.86	8.13	1.220	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=27 CYID=141 fcid=2714100004 name=NSP - Sherburne Generating Plant

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
27	141	2714100004	SV001	EU001	001	10100222	SO2	16.76	17.36	3.719	0.3	0.850	SCRUBBER	Scrubber added by LADCO
27	141	2714100004	SV001	EU002	001	10100222	SO2	22.55	23.34	5.002	0.3	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								39.31	40.70	8.721				
cyid								39.31	40.70	8.721				
stid								81.16	84.02	25.023				

STID=39 CYID=13 fcid=0607130015 name=R. E. BURGER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	13	0607130015	R6	B011	B011P1	10100202	SO2	29.83	31.15	3.115	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	13	0607130015	R7	B012	B012P1	10100202	SO2	34.77	36.31	3.631	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								64.60	67.46	6.746				
cyid								64.60	67.46	6.746				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	SO2	316.00	330.00	33.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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stid								380.60	397.46	39.746				

STID=47 CYID=1 fcid=0009 name=TVA BULL RUN FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	1	0009	S-1	001	99	10100212	SO2	130.81	133.01	13.301	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=47 CYID=73 fcid=0007 name=TVA JOHN SEVIER FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	73	0007	S-1A	001	99	10100212	SO2	20.15	20.49	2.049	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-1B	002	99	10100212	SO2	20.25	20.59	2.059	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2A	003	99	10100212	SO2	19.62	19.95	1.995	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2B	004	99	10100212	SO2	18.93	19.25	1.925	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								78.95	80.28	8.028				
cyid								78.95	80.28	8.028				

STID=47 CYID=85 fcid=0011 name=TVA JOHNSONVILLE FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	85	0011	S1-01	001	99	10100212	SO2	17.06	17.35	1.735	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-04	004	99	10100212	SO2	19.85	20.18	2.018	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-05	005	99	10100212	SO2	24.11	24.52	2.452	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								61.02	62.04	6.204				
cyid								61.02	62.04	6.204				

STID=47 CYID=145 fcid=0013 name=TVA KINGSTON FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	145	0013	S-1	001	99	10100202	SO2	12.68	12.89	1.289	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	002	99	10100202	SO2	14.00	14.24	1.424	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	003	99	10100202	SO2	13.80	14.04	1.404	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	004	99	10100202	SO2	12.24	12.44	1.244	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	005	99	10100202	SO2	19.57	19.90	1.990	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	006	99	10100202	SO2	18.92	19.24	1.924	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	007	99	10100202	SO2	21.30	21.66	2.166	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	008	99	10100202	SO2	18.54	18.85	1.885	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	009	99	10100202	SO2	20.72	21.07	2.107	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								151.77	154.33	15.433				
cyid								151.77	154.33	15.433				

STID=47 CYID=165 fcid=0025 name=TVA GALLATIN FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	165	0025	S-01	001	99	10100212	SO2	13.91	14.14	1.414	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-01	002	99	10100212	SO2	14.87	15.12	1.512	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	003	99	10100212	SO2	16.33	16.60	1.660	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	004	99	10100212	SO2	20.39	20.73	2.073	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								65.49	66.59	6.659				
cyid								65.49	66.59	6.659				
stid								488.04	496.25	49.625				

STID=54 CYID=51 fcid=0005 name=OHIO POWER - MITCHELL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0005	012	001	99	10100202	SO2	17.77	18.56	1.856	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0005	012	002	99	10100202	SO2	5.69	5.94	0.594	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								23.46	24.50	2.450				
cyid								23.46	24.50	2.450				

STID=54 CYID=53 fcid=0009 name=APPALACHIAN POWER - MOUNTAINEER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	53	0009	001	001	99	10100202	SO2	11.20	11.69	1.169	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=54 CYID=79 fcid=0006 name=APPALACHIAN POWER - JOHN E AMOS PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	79	0006	012	001	99	10100202	SO2	79.63	83.16	8.316	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	012	002	99	10100202	SO2	100.33	104.78	10.478	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	003	003	99	10100202	SO2	139.38	145.55	14.555	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								319.35	333.50	33.350				
cyid								319.35	333.50	33.350				
stid								354.00	369.69	36.969				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	SO2	12.75	14.54	3.490	0.0	0.760	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S13	B26	01	10100202	SO2	8.68	9.89	2.473	0.0	0.750	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B27	01	10100212	SO2	10.97	12.51	2.876	0.0	0.770	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B28	01	10100212	SO2	11.28	12.86	2.958	0.0	0.770	SCRUBBER	Scrubber added by LADCO
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fcid								43.68	49.80	11.797				
cyid								43.68	49.80	11.797				
stid								43.68	49.80	11.797				
								========	========	==========				
								1950.90	2075.80	287.480				

SO2 – 2018

Point Source Grown and Controlled Emissions by facility for SO2 r6s1b_2018

Base Year = 2002

Future Year = 2018

STID=17 CYID=31 fcid=031600AIN name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AIN	0010	0013	01	10100226	SO2	10.92	12.39	1.239	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	31	031600AIN	0012	0016	01	10100226	SO2	17.69	20.08	2.008	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								28.61	32.48	3.248				

STID=17 CYID=31 fcid=031600AMI name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	31	031600AMI	0007	0010	01	10100226	SO2	16.13	18.31	1.831	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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cyid								44.74	50.79	5.079				

STID=17 CYID=79 fcid=079808AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	79	079808AAA	0003	0003	01	10100202	SO2	36.35	41.27	4.127	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	79	079808AAA	0012	0013	01	10100501	SO2	28.99	19.46	1.946	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								65.34	60.72	6.072				
cyid								65.34	60.72	6.072				

STID=17 CYID=97 fcid=097190AAC name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	97	097190AAC	0018	0033	01	10100226	SO2	24.14	27.40	2.740	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0021	0036	01	10100226	SO2	19.23	21.83	2.183	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	97	097190AAC	0016	0031	01	10100203	SO2	4.59	5.22	0.005	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								47.96	54.45	4.928				
cyid								47.96	54.45	4.928				

STID=17 CYID=125 fcid=125804AAB name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	125	125804AAB	0019	0023	01	10100202	SO2	22.34	25.36	3.805	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=127 fcid=127855AAC name=ELECTRIC ENERGY INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes

17	127	127855AAC	0002	0003	01	10100222	SO2	10.25	11.63	11.630	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0002	0004	01	10100222	SO2	12.04	13.67	13.673	0.0	0.000	LNB	LNB added by LADCO
17	127	127855AAC	0001	0001	01	10100222	SO2	11.83	13.42	1.342	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	127	127855AAC	0001	0002	01	10100222	SO2	11.48	13.03	1.303	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	127	127855AAC	0003	0005	01	10100222	SO2	11.72	13.31	1.331	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	127	127855AAC	0003	0006	01	10100222	SO2	12.68	14.39	1.439	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								70.00	79.46	30.719				
cyid								70.00	79.46	30.719				

STID=17 CYID=135 fcid=135803AAA name=AMEREN ENERGY GENERATING CO

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	135	135803AAA	0001	0001	01	10100203	SO2	32.99	37.45	3.745	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	135	135803AAA	0001	0003	01	10100203	SO2	72.92	82.77	8.277	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								105.91	120.22	12.022				
cyid								105.91	120.22	12.022				

STID=17 CYID=143 fcid=143805AAG name=AES ED EDWARDS STATION

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	143	143805AAG	0002	0004	01	10100202	SO2	15.28	17.34	1.734	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=17 CYID=157 fcid=157851AAA name=DYNEGY MIDWEST GENERATION INC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	157	157851AAA	0001	0001	01	10100203	SO2	25.14	28.54	4.281	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0002	0002	01	10100203	SO2	25.79	29.28	4.392	0.0	0.850	SCRUBBER	Scrubber added by LADCO
17	157	157851AAA	0013	0013	01	10100202	SO2	27.79	31.54	4.732	0.0	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								78.72	89.36	13.404				
cyid								78.72	89.36	13.404				

STID=17 CYID=167 fcid=167120AAO name=CITY WATER LIGHT & POWER

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	167	167120AAO	0010	0012	01	10100203	SO2	44.20	50.18	0.050	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	167	167120AAO	0010	0013	01	10100203	SO2	16.40	18.62	0.019	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								60.61	68.80	0.069				
cyid								60.61	68.80	0.069				

STID=17 CYID=179 fcid=179801AAA name=MIDWEST GENERATION LLC

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
17	179	179801AAA	0018	0029	01	10100203	SO2	25.35	28.77	2.877	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	179	179801AAA	0018	0031	01	10100203	SO2	41.57	47.19	4.719	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.91	75.96	7.596				
cyid								66.91	75.96	7.596				

STID=17 CYID=197 fcid=197809AAO name=MIDWEST GENERATION LLC

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
17	197	197809AAO	0006	0009	01	10100203	SO2	15.89	18.04	1.804	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197809AAO	0016	0031	01	10100202	SO2	27.43	31.13	3.113	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197809AAO	0017	0033	01	10100202	SO2	23.13	26.26	2.626	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.45	75.44	7.544				

STID=17 CYID=197 fcid=197810AAK name=MIDWEST GENERATION LLC

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
17	197	197810AAK	0009	0014	02	10100222	SO2	11.64	13.21	1.321	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197810AAK	0011	0016	02	10100222	SO2	25.67	29.14	2.914	0.0	0.900	SCRUBBER	Scrubber added by LADCO
17	197	197810AAK	0013	0010	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	02	10100223	SO2	15.33	17.40	0.017	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
17	197	197810AAK	0007	0012	03	10100501	SO2	0.00	0.00	0.000	0.0	0.999	SHUTDOWN	Scrubber added by LADCO
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fcid								52.64	59.75	4.252				
cyid								119.09	135.19	11.796				
stid								696.90	777.66	97.225				

STID=18 CYID=147 fcid=00020 name=INDIANA MICHIGAN POWER-ROCKPORT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
18	147	00020	1	001	01	10100222	SO2	66.42	72.32	7.232	0.0	0.900	SCRUBBER	Scrubber added by LADCO
18	147	00020	1	001	02	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								66.42	72.32	7.232				
cyid								66.42	72.32	7.232				
stid								66.42	72.32	7.232				

STID=19 CYID=115 fcid=58-07-001 name=MIDAMERICAN ENERGY CO. - LOUISA STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
19	115	58-07-001	117487	147281	99	10100222	SO2	33.66	38.22	3.822	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=127 fcid=2112700003 name=KENTUCKY POWER CO

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
21	127	2112700003	2	002	99	10100202	SO2	104.52	113.82	11.382	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=21 CYID=161 fcid=2116100009 name=EAST KY POWER COOP

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes

21	161	2116100009	1	001	99	10100202	SO2	42.17	45.92	4.592	0.0	0.900	SCRUBBER	Scrubber added by LADCO
21	161	2116100009	2	002	99	10100212	SO2	55.39	60.31	6.031	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								97.55	106.23	10.623				
cyid								97.55	106.23	10.623				
stid								202.07	220.04	22.004				

STID=27 CYID=61 fcid=2706100004 name=Minnesota Power Inc - Boswell Energy Ctr

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
27	61	2706100004	SV003	EU003	001	10100226	SO2	33.99	39.15	16.778	0.3	0.700	SCRUBBER	Scrubber added by LADCO
27	61	2706100004	SV003	EU003	002	10100501	SO2	0.00	0.00	0.000	0.3	0.700	SCRUBBER	Scrubber added by LADCO
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fcid								33.99	39.15	16.778				
cyid								33.99	39.15	16.778				

STID=27 CYID=109 fcid=2710900011 name=Rochester Public Utilities - Silver Lake

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
27	109	2710900011	SV003	EU004	001	10100202	SO2	7.86	9.05	1.357	0.0	0.850	SCRUBBER	Scrubber added by LADCO

STID=27 CYID=141 fcid=2714100004 name=NSP - Sherburne Generating Plant

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
27	141	2714100004	SV001	EU001	001	10100222	SO2	16.76	19.31	4.138	0.3	0.850	SCRUBBER	Scrubber added by LADCO
27	141	2714100004	SV001	EU002	001	10100222	SO2	22.55	25.97	5.565	0.3	0.850	SCRUBBER	Scrubber added by LADCO
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fcid								39.31	45.28	9.703				
cyid								39.31	45.28	9.703				
stid								81.16	93.48	27.838				

STID=39 CYID=13 fcid=0607130015 name=R. E. BURGER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
39	13	0607130015	R6	B011	B011P1	10100202	SO2	29.83	32.48	3.248	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	13	0607130015	R7	B012	B012P1	10100202	SO2	34.77	37.86	3.786	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								64.60	70.34	7.034				
cyid								64.60	70.34	7.034				

STID=39 CYID=31 fcid=0616000000 name=CONESVILLE POWER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
39	31	0616000000	R4	B004	B004P1	10100212	SO2	316.00	344.11	34.411	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=39 CYID=167 fcid=0684000000 name=MUSKINGUM RIVER POWER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes

39	167	0684000000	R2	B002	B002P1	10100201	SO2	65.07	70.85	7.085	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R2	B002	B002P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R3	B003	B003P1	10100201	SO2	94.58	103.00	10.300	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R3	B003	B003P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R4	B004	B004P1	10100203	SO2	81.64	88.90	8.890	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R4	B004	B004P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R5	B005	B005P1	10100203	SO2	97.22	105.87	10.587	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R5	B005	B005P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R6	B006	B006P1	10100202	SO2	113.96	124.10	12.410	0.0	0.900	SCRUBBER	Scrubber added by LADCO
39	167	0684000000	R6	B006	B006P2	10100501	SO2	0.00	0.00	0.000	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								452.48	492.72	49.272				
cyid								452.48	492.72	49.272				
stid								833.08	907.16	90.716				

STID=47 CYID=1 fcid=0009 name=TVA BULL RUN FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	1	0009	S-1	001	99	10100212	SO2	130.81	136.82	13.682	0.0	0.900	SCRUBBER	Scrubber added by LADCO

STID=47 CYID=73 fcid=0007 name=TVA JOHN SEVIER FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	73	0007	S-1A	001	99	10100212	SO2	20.15	21.07	2.107	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-1B	002	99	10100212	SO2	20.25	21.18	2.118	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2A	003	99	10100212	SO2	19.62	20.52	2.052	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	73	0007	S-2B	004	99	10100212	SO2	18.93	19.80	1.980	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								78.95	82.57	8.257				
cyid								78.95	82.57	8.257				

STID=47 CYID=85 fcid=0011 name=TVA JOHNSONVILLE FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	85	0011	S1-01	001	99	10100212	SO2	17.06	17.84	1.784	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-04	004	99	10100212	SO2	19.85	20.76	2.076	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	85	0011	S1-05	005	99	10100212	SO2	24.11	25.22	2.522	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								61.02	63.82	6.382				
cyid								61.02	63.82	6.382				

STID=47 CYID=145 fcid=0013 name=TVA KINGSTON FOSSIL PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
47	145	0013	S-1	001	99	10100202	SO2	12.68	13.26	1.326	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	002	99	10100202	SO2	14.00	14.65	1.465	0.0	0.900	SCRUBBER	Scrubber added by LADCO

47	145	0013	S-1	003	99	10100202	SO2	13.80	14.44	1.444	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	004	99	10100202	SO2	12.24	12.80	1.280	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-1	005	99	10100202	SO2	19.57	20.47	2.047	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	006	99	10100202	SO2	18.92	19.79	1.979	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	007	99	10100202	SO2	21.30	22.28	2.228	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	008	99	10100202	SO2	18.54	19.39	1.939	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	145	0013	S-2	009	99	10100202	SO2	20.72	21.68	2.168	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								151.77	158.75	15.875				
cyid								151.77	158.75	15.875				

STID=47 CYID=165 fcid=0025 name=TVA GALLATIN FOSSIL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
47	165	0025	S-01	001	99	10100212	SO2	13.91	14.54	1.454	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-01	002	99	10100212	SO2	14.87	15.56	1.556	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	003	99	10100212	SO2	16.33	17.08	1.708	0.0	0.900	SCRUBBER	Scrubber added by LADCO
47	165	0025	S-02	004	99	10100212	SO2	20.39	21.32	2.132	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								65.49	68.50	6.850				
cyid								65.49	68.50	6.850				
stid								488.04	510.46	51.046				

STID=54 CYID=39 fcid=0006 name=APPALACHIAN POWER - KANAWHA RIVER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	39	0006	012	001	99	10100202	SO2	19.45	21.18	10.591	0.0	0.500	SCRUBBER	Scrubber added by LADCO
54	39	0006	012	002	99	10100202	SO2	20.94	22.80	11.399	0.0	0.500	SCRUBBER	Scrubber added by LADCO
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fcid								40.39	43.98	21.990				
cyid								40.39	43.98	21.990				

STID=54 CYID=51 fcid=0005 name=OHIO POWER - MITCHELL PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0005	012	001	99	10100202	SO2	17.77	19.36	1.936	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0005	012	002	99	10100202	SO2	5.69	6.19	0.619	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								23.46	25.55	2.555				

STID=54 CYID=51 fcid=0006 name=OHIO POWER - KAMMER PLANT

STID	CYID	fcid	stkid	dvid	prid	scc	polid	Base Yr Tons/Day	Grown Tons/Day	Controlled Tons/Day	Base Year Control EF	Future Year Control EF	ctrltype	ctrldes
54	51	0006	013	001	99	10100203	SO2	47.06	51.25	5.125	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0006	013	002	99	10100203	SO2	47.66	51.90	5.190	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	51	0006	013	003	99	10100203	SO2	41.94	45.67	4.567	0.0	0.900	SCRUBBER	Scrubber added by LADCO

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fcid								136.67	148.82	14.882				
cyid								160.13	174.37	17.437				

STID=54 CYID=53 fcid=0001 name=APPALACHIAN POWER CO.-PHILIP SPORN PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	53	0001	014	001	99	10100202	SO2	18.65	20.31	2.031	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	014	002	99	10100202	SO2	15.87	17.28	1.728	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	014	003	99	10100202	SO2	21.46	23.36	2.336	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	014	004	99	10100202	SO2	20.53	22.36	2.236	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	53	0001	005	005	99	10100202	SO2	46.82	50.98	5.098	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								123.33	134.30	13.430				

STID=54 CYID=53 fcid=0009 name=APPALACHIAN POWER - MOUNTAINEER PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	53	0009	001	001	99	10100202	SO2	11.20	12.19	1.219	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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cyid								134.53	146.49	14.649				

STID=54 CYID=79 fcid=0006 name=APPALACHIAN POWER - JOHN E AMOS PLANT

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
54	79	0006	012	001	99	10100202	SO2	79.63	86.72	8.672	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	012	002	99	10100202	SO2	100.33	109.26	10.926	0.0	0.900	SCRUBBER	Scrubber added by LADCO
54	79	0006	003	003	99	10100202	SO2	139.38	151.77	15.177	0.0	0.900	SCRUBBER	Scrubber added by LADCO
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fcid								319.35	347.75	34.775				
cyid								319.35	347.75	34.775				
stid								654.39	712.59	88.851				

STID=55 CYID=79 fcid=241007690 name=WIS ELECTRIC POWER OAK CREEK STATION

								Base Yr	Grown	Controlled	Base Year	Future Year		
STID	CYID	fcid	stkid	dvid	prid	scc	polid	Tons/Day	Tons/Day	Tons/Day	Control EF	Control EF	ctrltype	ctrldes
55	79	241007690	S13	B25	01	10100202	SO2	12.75	14.48	3.475	0.0	0.760	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S13	B26	01	10100202	SO2	8.68	9.85	2.462	0.0	0.750	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B27	01	10100212	SO2	10.97	12.45	2.864	0.0	0.770	SCRUBBER	Scrubber added by LADCO
55	79	241007690	S14	B28	01	10100212	SO2	11.28	12.81	2.945	0.0	0.770	SCRUBBER	Scrubber added by LADCO
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fcid								43.68	49.59	11.746				
cyid								43.68	49.59	11.746				
stid								43.68	49.59	11.746				
								========	========	==========				
								3099.41	3381.52	400.481				

Appendix II

Scenario C Controls (CAMD List)

NOx Controls (SCRs, 2007 – 2013))

Plant Name	UniqueID_Final	State Name	County	Capacity MW	On Line Year	SCR Online Year
Chesterfield	3797_B_4	Virginia	Chesterfield	166	1960	2013
Chesterfield	3797_B_5	Virginia	Chesterfield	310	1964	2012
Scherer	6257_B_3	Georgia	Monroe	875	1987	2011
Chesterfield	3797_B_6	Virginia	Chesterfield	658	1969	2011
Sandow No 4	6648_B_4	Texas	Milam	545	1981	2011
Beech Hollow Power Project	82704_B_1	Pennsylvania	Washington	272	2011	2011
Longview Power	82702_B_1	West Virginia	Monongalia	695	2011	2011
Cliffside	2721_B_6	North Carolina	Cleveland	800	2011	2011
AES Westover	2526_B_11	New York	Broome	22	1943	2010
AES Westover	2526_B_12	New York	Broome	22	1943	2010
AES Westover	2526_B_13	New York	Broome	84	1951	2010
Iatan 2	6065_B_2	Missouri	Platte	850	2010	2010
Southwest	6195_B_2	Missouri	Greene	300	2010	2010
Trimble Station (LGE)	6071_B_2	Kentucky	Trimble	732	2010	2010
Elm Road Generating Station	56068_B_2	Wisconsin	Milwaukee	615	2010	2010
Clay Boswell	1893_B_3	Minnesota	Itasca	350	1973	2009
Asheville	2706_B_2	North Carolina	Buncombe	184	1971	2009
Conesville	2840_B_4	Ohio	Coshocton	780	1973	2009
Marshall	2727_B_3	North Carolina	Catawba	657	1969	2009
St Johns River Power Park	207_B_1	Florida	Duval	626	1987	2009
Ghent	1356_B_2	Kentucky	Carroll	469	1977	2009
Chalk Point LLC	1571_B_1	Maryland	Prince George's	341	1964	2009
Chalk Point LLC	1571_B_2	Maryland	Prince George's	342	1965	2009
San Juan	2451_B_2	New Mexico	San Juan	320	1973	2009
Big Bend	645_B_BB01	Florida	Hillsborough	411	1970	2009
Big Bend	645_B_BB02	Florida	Hillsborough	391	1973	2009
Big Bend	645_B_BB03	Florida	Hillsborough	414	1976	2009
Nebraska City Unit 2	6096_B_2	Nebraska	Otoe	663	2009	2009
Cross	130_B_4	South Carolina	Berkeley	652	2009	2009
Springerville	8223_B_4	Arizona	Apache	400	2009	2009
Sandow 5	82010_B_5	Texas	Milam	600	2009	2009
Oak Grove	82011_B_1	Texas	Robertson	800	2009	2009
Oak Grove	82011_B_2	Texas	Robertson	800	2009	2009
TS Power Plant	82013_B_1	Nevada	Eureka	200	2009	2009
Plum Point Energy	82014_B_1	Arkansas	Mississippi	665	2009	2009
Comanche	470_B_3	Colorado	Pueblo	750	2009	2009
Elm Road Generating Station	56068_B_1	Wisconsin	Milwaukee	615	2009	2009
Two Elk Generating Station	55360_B_1	Wyoming	Campbell	300	2009	2009
J K Spruce	7097_B_BLR2	Texas	Bexar	750	2009	2009
Dallman	963_B_34	Illinois	Sangamon	200	2009	2009
AES Greenidge LLC	2527_B_4	New York	Yates	27	1950	2008
AES Greenidge LLC	2527_B_5	New York	Yates	27	1950	2008
AES Greenidge LLC	2527_B_6	New York	Yates	106	1953	2008
Charles R Lowman	56_B_2	Alabama	Washington	238	1979	2008
Charles R Lowman	56_B_3	Alabama	Washington	238	1980	2008
Barry	3_B_5	Alabama	Mobile	750	1971	2008
St Johns River Power Park	207_B_2	Florida	Duval	626	1988	2008
Morgantown Generating Plant	1573_B_2	Maryland	Charles	620	1971	2008

Bailly	995_B_7	Indiana	Porter	160	1962	2008
San Juan	2451_B_1	New Mexico	San Juan	322	1976	2008
San Juan	2451_B_3	New Mexico	San Juan	495	1979	2008
Weston	4078_B_4	Wisconsin	Marathon	519	2008	2008
AES Deepwater	10670_B_AAB001	Texas	Harris	140	1986	2007
La Cygne	1241_B_1	Kansas	Linn	724	1973	2007
Morgantown Generating Plant	1573_B_1	Maryland	Charles	624	1970	2007
PSEG Hudson Generating Station	2403_B_2	New Jersey	Hudson	583	1967	2007
San Juan	2451_B_4	New Mexico	San Juan	506	1982	2007
Big Bend	645_B_BB04	Florida	Hillsborough	457	1985	2007
Cross	130_B_3	South Carolina	Berkeley	620	2007	2007
Wygen II	55479_B_4	Wyoming	Campbell	90	2007	2007
Council Bluffs	1082_B_4	Iowa	Pottawattamie	790	2007	2007

SO2 Controls (FGDs, 2007 – 2012)

Plant Name	UniqueID_Final	State Name	County	Capacity MW	On Line Year	Scrubber Online Year
James H Miller Jr	6002_B_1	Alabama	Jefferson	684	1978	2011
James H Miller Jr	6002_B_2	Alabama	Jefferson	687	1985	2011
James H Miller Jr	6002_B_3	Alabama	Jefferson	687	1989	2011
James H Miller Jr	6002_B_4	Alabama	Jefferson	688	1991	2011
Cape Fear	2708_B_5	North Carolina	Chatham	143	1956	2011
Baldwin Energy Complex	889_B_1	Illinois	Randolph	624	1970	2011
Baldwin Energy Complex	889_B_2	Illinois	Randolph	629	1973	2011
Baldwin Energy Complex	889_B_3	Illinois	Randolph	629	1975	2011
Scherer	6257_B_3	Georgia	Monroe	875	1987	2011
Milton R Young	2823_B_B1	North Dakota	Oliver	250	1970	2011
W H Sammis	2866_B_6	Ohio	Jefferson	630	1969	2011
W H Sammis	2866_B_7	Ohio	Jefferson	630	1971	2011
PSEG Hudson Generating Station	2403_B_2	New Jersey	Hudson	583	1967	2011
John Sevier	3405_B_1	Tennessee	Hawkins	176	1955	2011
John Sevier	3405_B_2	Tennessee	Hawkins	176	1955	2011
John Sevier	3405_B_3	Tennessee	Hawkins	176	1956	2011
John Sevier	3405_B_4	Tennessee	Hawkins	176	1957	2011
Beech Hollow Power Project	82704_B_1	Pennsylvania	Washington	272	2011	2011
Longview Power	82702_B_1	West Virginia	Monongalia	695	2011	2011
Cliffside	2721_B_6	North Carolina	Cleveland	800	2011	2011
AES Greenidge LLC	2527_B_4	New York	Yates	27	1950	2010
AES Greenidge LLC	2527_B_5	New York	Yates	27	1950	2010
Barry	3_B_5	Alabama	Mobile	750	1971	2010
E C Gaston	26_B_5	Alabama	Shelby	861	1974	2010
Warrick	6705_B_4	Indiana	Warrick	300	1970	2010
Coffeen	861_B_01	Illinois	Montgomery	340	1965	2010
Coffeen	861_B_02	Illinois	Montgomery	560	1972	2010
Cardinal	2828_B_3	Ohio	Jefferson	630	1977	2010
Brandon Shores	602_B_1	Maryland	Anne Arundel	643	1984	2010
Brandon Shores	602_B_2	Maryland	Anne Arundel	643	1991	2010
Monroe	1733_B_4	Michigan	Monroe	775	1974	2010
Cliffside	2721_B_5	North Carolina	Cleveland	550	1972	2010
Crystal River	628_B_4	Florida	Citrus	720	1982	2010
Bowen	703_B_1BLR	Georgia	Bartow	713	1971	2010

Crist	641_B_6	Florida	Escambia	302	1970	2010
Crist	641_B_7	Florida	Escambia	477	1973	2010
Clifty Creek	983_B_1	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_2	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_3	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_4	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_5	Indiana	Jefferson	217	1955	2010
Clifty Creek	983_B_6	Indiana	Jefferson	217	1956	2010
Chalk Point LLC	1571_B_1	Maryland	Prince George's	341	1964	2010
Chalk Point LLC	1571_B_2	Maryland	Prince George's	342	1965	2010
Dickerson	1572_B_1	Maryland	Montgomery	182	1959	2010
Dickerson	1572_B_2	Maryland	Montgomery	182	1960	2010
Dickerson	1572_B_3	Maryland	Montgomery	182	1962	2010
R E Burger	2864_B_7	Ohio	Belmont	156	1955	2010
R E Burger	2864_B_8	Ohio	Belmont	156	1955	2010
Kyger Creek	2876_B_1	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_2	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_3	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_4	Ohio	Gallia	217	1955	2010
Kyger Creek	2876_B_5	Ohio	Gallia	217	1955	2010
Cheswick	8226_B_1	Pennsylvania	Allegheny	580	1970	2010
PSEG Mercer Generating Station	2408_B_1	New Jersey	Mercer	315	1960	2010
PSEG Mercer Generating Station	2408_B_2	New Jersey	Mercer	310	1961	2010
Silver Lake	2008_B_4	Minnesota	Olmsted	61	1969	2010
Kingston	3407_B_1	Tennessee	Roane	135	1954	2010
Kingston	3407_B_2	Tennessee	Roane	135	1954	2010
Kingston	3407_B_3	Tennessee	Roane	135	1954	2010
Kingston	3407_B_4	Tennessee	Roane	135	1954	2010
Kingston	3407_B_5	Tennessee	Roane	177	1955	2010
Kingston	3407_B_6	Tennessee	Roane	177	1955	2010
Kingston	3407_B_7	Tennessee	Roane	177	1955	2010
Kingston	3407_B_8	Tennessee	Roane	177	1955	2010
Kingston	3407_B_9	Tennessee	Roane	178	1955	2010
Sioux	2107_B_1	Missouri	St. Charles	497	1967	2010
Sioux	2107_B_2	Missouri	St. Charles	497	1968	2010
Chesterfield	3797_B_5	Virginia	Chesterfield	310	1964	2010
Yorktown	3809_B_1	Virginia	York	159	1957	2010
AES Westover	2526_B_11	New York	Broome	22	1943	2010
AES Westover	2526_B_12	New York	Broome	22	1943	2010
AES Westover	2526_B_13	New York	Broome	84	1951	2010
Iatan 2	6065_B_2	Missouri	Platte	850	2010	2010
Southwest	6195_B_2	Missouri	Greene	300	2010	2010
Trimble Station (LGE)	6071_B_2	Kentucky	Trimble	732	2010	2010
Elm Road Generating Station	56068_B_2	Wisconsin	Milwaukee	615	2010	2010
Cholla	113_B_3	Arizona	Navajo	271	1980	2009
Mayo	6250_B_1A	North Carolina	Person	362	1983	2009
Mayo	6250_B_1B	North Carolina	Person	362	1983	2009
Conesville	2840_B_4	Ohio	Coshocton	780	1973	2009
G G Allen	2718_B_1	North Carolina	Gaston	162	1957	2009
G G Allen	2718_B_2	North Carolina	Gaston	162	1957	2009
G G Allen	2718_B_3	North Carolina	Gaston	260	1959	2009

G G Allen	2718_B_4	North Carolina	Gaston	275	1960	2009
G G Allen	2718_B_5	North Carolina	Gaston	265	1961	2009
H L Spurlock	6041_B_1	Kentucky	Mason	315	1977	2009
Crystal River	628_B_5	Florida	Citrus	717	1984	2009
Deerhaven Generating Station	663_B_B2	Florida	Alachua	228	1981	2009
Bowen	703_B_2BLR	Georgia	Bartow	718	1972	2009
Wansley	6052_B_2	Georgia	Heard	892	1978	2009
E W Brown	1355_B_1	Kentucky	Mercer	94	1957	2009
E W Brown	1355_B_2	Kentucky	Mercer	160	1963	2009
E W Brown	1355_B_3	Kentucky	Mercer	422	1971	2009
Ghent	1356_B_2	Kentucky	Carroll	469	1977	2009
Fayette Power Project	6179_B_1	Texas	Fayette	598	1979	2009
Fayette Power Project	6179_B_2	Texas	Fayette	598	1980	2009
Morgantown Generating Plant	1573_B_1	Maryland	Charles	624	1970	2009
Morgantown Generating Plant	1573_B_2	Maryland	Charles	620	1971	2009
PPL Brunner Island	3140_B_1	Pennsylvania	York	321	1961	2009
PPL Brunner Island	3140_B_2	Pennsylvania	York	378	1965	2009
Keystone	3136_B_1	Pennsylvania	Armstrong	850	1967	2009
Keystone	3136_B_2	Pennsylvania	Armstrong	850	1968	2009
Bull Run	3396_B_1	Tennessee	Anderson	881	1967	2009
Bay Shore	2878_B_4	Ohio	Lucas	215	1968	2009
Hatfields Ferry Power Station	3179_B_1	Pennsylvania	Greene	530	1969	2009
Hatfields Ferry Power Station	3179_B_2	Pennsylvania	Greene	530	1970	2009
Hatfields Ferry Power Station	3179_B_3	Pennsylvania	Greene	530	1971	2009
Nebraska City Unit 2	6096_B_2	Nebraska	Otoe	663	2009	2009
Cross	130_B_4	South Carolina	Berkeley	652	2009	2009
Springerville	8223_B_4	Arizona	Apache	400	2009	2009
Sandow 5	82010_B_5	Texas	Milam	600	2009	2009
Oak Grove	82011_B_1	Texas	Robertson	800	2009	2009
Oak Grove	82011_B_2	Texas	Robertson	800	2009	2009
TS Power Plant	82013_B_1	Nevada	Eureka	200	2009	2009
Plum Point Energy	82014_B_1	Arkansas	Mississippi	665	2009	2009
Comanche	470_B_3	Colorado	Pueblo	750	2009	2009
Elm Road Generating Station	56068_B_1	Wisconsin	Milwaukee	615	2009	2009
Two Elk Generating Station	55360_B_1	Wyoming	Campbell	300	2009	2009
J K Spruce	7097_B_BLR2	Texas	Bexar	750	2009	2009
Dallman	963_B_34	Illinois	Sangamon	200	2009	2009
Charles R Lowman	56_B_1	Alabama	Washington	86	1969	2008
John E Amos	3935_B_1	West Virginia	Putnam	800	1971	2008
John E Amos	3935_B_2	West Virginia	Putnam	800	1972	2008
Cholla	113_B_4	Arizona	Navajo	380	1981	2008
Roxboro	2712_B_1	North Carolina	Person	369	1966	2008
Roxboro	2712_B_3A	North Carolina	Person	341	1973	2008
Roxboro	2712_B_3B	North Carolina	Person	341	1973	2008
Miami Fort	2832_B_7	Ohio	Hamilton	500	1975	2008
Miami Fort	2832_B_8	Ohio	Hamilton	500	1978	2008
Cogentrix Virginia Leasing Corp	10071_B_2A	Virginia	Portsmouth	19	1988	2008
Cogentrix Virginia Leasing Corp	10071_B_2B	Virginia	Portsmouth	19	1988	2008
Cogentrix Virginia Leasing Corp	10071_B_2C	Virginia	Portsmouth	19	1988	2008
J M Stuart	2850_B_1	Ohio	Adams	585	1971	2008
J M Stuart	2850_B_2	Ohio	Adams	597	1970	2008

J M Stuart	2850_B_3	Ohio	Adams	597	1972	2008
J M Stuart	2850_B_4	Ohio	Adams	597	1974	2008
Monroe	1733_B_3	Michigan	Monroe	795	1973	2008
Belews Creek	8042_B_1	North Carolina	Stokes	1,115	1974	2008
Belews Creek	8042_B_2	North Carolina	Stokes	1,115	1975	2008
Bowen	703_B_3BLR	Georgia	Bartow	902	1974	2008
Bowen	703_B_4BLR	Georgia	Bartow	929	1975	2008
Hammond	708_B_1	Georgia	Floyd	112	1954	2008
Hammond	708_B_2	Georgia	Floyd	112	1954	2008
Hammond	708_B_3	Georgia	Floyd	112	1955	2008
Hammond	708_B_4	Georgia	Floyd	510	1970	2008
Wansley	6052_B_1	Georgia	Heard	891	1976	2008
Harding Street	990_B_70	Indiana	Marion	435	1973	2008
Cogentrix Hopewell	10377_B_1A	Virginia	Hopewell (city)	18	1987	2008
Cogentrix Hopewell	10377_B_1B	Virginia	Hopewell (city)	18	1987	2008
Cogentrix Hopewell	10377_B_1C	Virginia	Hopewell (city)	18	1987	2008
Ghent	1356_B_4	Kentucky	Carroll	478	1984	2008
Council Bluffs	1082_B_3	Iowa	Pottawattamie	690	1978	2008
PPL Brunner Island	3140_B_3	Pennsylvania	York	749	1969	2008
PPL Montour	3149_B_1	Pennsylvania	Montour	774	1972	2008
PPL Montour	3149_B_2	Pennsylvania	Montour	766	1973	2008
Comanche	470_B_1	Colorado	Pueblo	366	1973	2008
Comanche	470_B_2	Colorado	Pueblo	370	1975	2008
Cayuga	1001_B_2	Indiana	Vermillon	473	1972	2008
Winyah	6249_B_1	South Carolina	Georgetown	295	1975	2008
Winyah	6249_B_2	South Carolina	Georgetown	295	1977	2008
Winyah	6249_B_3	South Carolina	Georgetown	295	1980	2008
Chesterfield	3797_B_6	Virginia	Chesterfield	658	1969	2008
Brayton Point	1619_B_1	Massachusetts	Bristo	243	1963	2008
Brayton Point	1619_B_2	Massachusetts	Bristo	244	1964	2008
Weston	4078_B_4	Wisconsin	Marathon	519	2008	2008
Gorgas	8_B_10	Alabama	Walker	690	1972	2007
Gorgas	8_B_8	Alabama	Walker	165	1956	2007
Gorgas	8_B_9	Alabama	Walker	175	1958	2007
John E Amos	3935_B_3	West Virginia	Putnam	1,300	1973	2007
Mountaineer	6264_B_1	West Virginia	Mason	1,300	1980	2007
Cardinal	2828_B_1	Ohio	Jefferson	600	1967	2007
Cardinal	2828_B_2	Ohio	Jefferson	600	1967	2007
Roxboro	2712_B_2	North Carolina	Person	639	1968	2007
Roxboro	2712_B_4A	North Carolina	Person	343	1980	2007
Roxboro	2712_B_4B	North Carolina	Person	343	1980	2007
Cogentrix Virginia Leasing Corp	10071_B_1A	Virginia	Portsmouth	19	1988	2007
Cogentrix Virginia Leasing Corp	10071_B_1B	Virginia	Portsmouth	19	1988	2007
Cogentrix Virginia Leasing Corp	10071_B_1C	Virginia	Portsmouth	19	1988	2007
Killen Station	6031_B_2	Ohio	Adams	615	1982	2007
Marshall	2727_B_2	North Carolina	Catawba	378	1966	2007
Marshall	2727_B_3	North Carolina	Catawba	657	1969	2007
Cogentrix Hopewell	10377_B_2A	Virginia	Hopewell (city)	18	1987	2007
Cogentrix Hopewell	10377_B_2B	Virginia	Hopewell (city)	18	1987	2007
Cogentrix Hopewell	10377_B_2C	Virginia	Hopewell (city)	18	1987	2007
Ghent	1356_B_3	Kentucky	Carroll	478	1981	2007

Louisa	6664_B_101	Iowa	Louisa	700	1983	2007
Allen S King	1915_B_1	Minnesota	Washington	571	1968	2007
Mitchell	3948_B_1	West Virginia	Marshall	800	1971	2007
Gibson	6113_B_1	Indiana	Gibson	630	1975	2007
Gibson	6113_B_2	Indiana	Gibson	628	1975	2007
Winyah	6249_B_4	South Carolina	Georgetown	270	1981	2007
Pleasant Prairie	6170_B_2	Wisconsin	Kenosha	617	1985	2007
Cross	130_B_3	South Carolina	Berkeley	620	2007	2007
Wygen II	55479_B_4	Wyoming	Campbell	90	2007	2007
Council Bluffs	1082_B_4	Iowa	Pottawattamie	790	2007	2007

Assumed BART Facilities and Units

State	County	Fac ID	Facility Name	Unit ID
MI	Bay	B2840	CE - KARN/WEADOCK	EU00036
MI	Bay	B2840	CE - KARN/WEADOCK	EU00037
MI	Eaton	B4001	LAN. BW&L ERICKSON	EU00007
MI	Houghton	B6553	UP POWER CO / PORTAGE	EU00008
MI	Huron	B2815	DTE - HARBOR BEACH	EU00009
MI	Ingham	B2647	LAN. BW&L Eckert	RG00023
MI	Ingham	B2647	LAN. BW&L Eckert	RG00023
MI	Ingham	B2647	LAN. BW&L Eckert	RG00023
MI	Ingham	B2647	LAN. BW&L Moores Park	RG00021
MI	Marquette	B4261	WE-ENERGIES	EU00029
MI	Marquette	B4261	WE-ENERGIES	EU00030
MI	Marquette	B4261	WE-ENERGIES	EU00031
MI	Marquette	B4261	WE-ENERGIES	EU00032
MI	Marquette	B4261	WE-ENERGIES	EU00033
MI	Monroe	B2816	DTE - MONROE	EU00062
MI	Monroe	B2816	DTE - MONROE	EU00068
MI	Monroe	B2816	DTE - MONROE	EU00063
MI	Monroe	B2816	DTE - MONROE	EU00064
MI	Ottawa	B2835	CE – CAMPBELL	EU00062
MI	Ottawa	B2835	CE – CAMPBELL	EU00061
MI	Saint Clair	B2796	DTE - ST. CLAIR / BELLE RIVER	EU00111
MI	Saint Clair	B6145	DTE – GREENWOOD	EU00009
MI	Wayne	B2132	WYANDOTTE	EU00036
MI	Wayne	B2185	DETROIT PLD, MISTERSKY	EU00014
MI	Wayne	B2811	DTE – TRENTON	EU00035
OH	Lake	0243160009	CEI., EASTLAKE PLANT	B005
OH		0247030013	Orion Power Midwest	B012
OH		0285010188	Dept of Public Utilities, City of Orrville	B001
OH		0285010188	Dept of Public Utilities, City of Orrville	B004
OH		0448020006	Toledo Edison Co., Bay Shore	B003
OH		0448020006	Toledo Edison Co., Bay Shore	B004
OH		0616000000	Conesville Power Plant	B003
OH		0616000000	Conesville Power Plant	B004
OH		0616000000	Conesville Power Plant	B007
OH		0641050002	Cardinal Power Plant	B001
OH		0641050002	Cardinal Power Plant	B002

OH		0641050002	Cardinal Power Plant	B003
OH		0641050002	Cardinal Power Plant	B004
OH		0641050002	Cardinal Power Plant	B008
OH		0641050002	Cardinal Power Plant	B009
OH		0641050002	Cardinal Power Plant	B009
OH	Jefferson	0641160017	W. H. SAMMIS PLANT	B011
OH	Jefferson	0641160017	W. H. SAMMIS PLANT	B012
OH	Jefferson	0641160017	W. H. SAMMIS PLANT	B013
OH		0684000000	Muskingum River Power Plant	B006
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B001
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B002
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B003
OH	Adams	0701000007	DP&L, J.M. Stuart Generating Station	B004
OH		0701000060	DP&L, Killen Station	B001
OH		1409040243	City of Hamilton Dept of Public Utilities	B002
OH		1409040243	City of Hamilton Dept of Public Utilities	B008
OH		1409040243	City of Hamilton Dept of Public Utilities	B009
OH		1413100008	CG&E W. C. BECKJORD	B005
OH		1413100008	CG&E W. C. BECKJORD	B006
OH		1431350093	CG&E MIAMI FORT STATION	B015
IL	Peoria	856	Ameren – Edwards	2
IL	Sangamon	963	CWLP – Dallman	31
IL	Sangamon	963	CWLP – Dallman	32
IL	Christian	876	Dominion – Kincaid	1
IL	Christian	876	Dominion – Kincaid	2
WI	COLUMBIA	111003090	Alliant Energy-Columbia Generating	B20
WI	COLUMBIA	111003090	Alliant Energy-Columbia Generating	B21
WI	COLUMBIA	111003090	Alliant Energy-Columbia Generating	B22
WI	GRANT	122014530	Alliant Energy, Nelson Dewey	B22 (unit 2)
WI	MILWAUKEE	241007690	We Energies-Oak Creek Station	B26 (Unit 6)
WI	MILWAUKEE	241007690	We Energies-Oak Creek Station	B27 (Unit 7)
WI	MILWAUKEE	241007690	We Energies-Oak Creek Station	B28
WI	MILWAUKEE	241007800	We Energies-Valley Station	B21
WI	MILWAUKEE	241007800	We Energies-Valley Station	B23
WI	MILWAUKEE	241007800	We Energies-Valley Station	B24
WI	BROWN	405031990	WI Public Service Corp - JP Pulliam	B27 (unit 8)
WI	SHEBOYGAN	460033090	WP & L Alliant Energy – Edgewater	B24
WI	BUFFALO	606034110	Dairyland Power Coop Alma Station (J.P. Madgett boilers)	B25 (+B26)
WI	BUFFALO	606034110	Dairyland Power Coop Alma Station	B27
WI	VERNON	663020930	Dairyland Power Coop Genoa Station	B20
WI	VERNON	663020930	Dairyland Power Coop Genoa Station	B25
IN	Porter	995	Bailly	7
IN	Porter	995	Bailly	8
IN	Vermillion	1001	Cayuga	1
IN	Vermillion	1001	Cayuga	2
IN	Montgomery	1024	Crawfordsville	6
IN	Warrick	1012	Culley	2

IN	Warrick	1012	Culley	3
IN	Gibson	6113	Gibson	1
IN	Gibson	6113	Gibson	2
IN	Cass	1032	Logansport	6
IN	Sullivan	6213	Merom	1
IN	Sullivan	6213	Merom	2
IN	LaPorte	997	Michigan City	12
IN	Lake	996	Mitchell	11
IN	Pike	994	Petersburg	1
IN	Pike	994	Petersburg	2
IN	Pike	994	Petersburg	3
IN	Pike	1043	Ratts	1
IN	Pike	1043	Ratts	2
IN	Wayne	7335	RPL	2
IN	Jasper	6085	Schahfer	14
IN	Jasper	6085	Schahfer	15
IN	Lake	981	Stateline	4
IN	Marion	990	Stout	70
IN	Dearborn	988	Tanners Creek	4
IN	Vigo	1010	Wabash River	6
IN	Warrick	6705	Warrick	4
IA		07-02-005	Cedar Falls Utilities	Unit #7 (EU10.1A)
IA		88-01-004	Central Iowa Power Cooperative (CIPCO) – Summit Lake Station	CombTurbines (EU 1/1G, EU2/2G)
IA		70-08-003	Central Iowa Power Cooperative (CIPCO) – Fair Station	Unit # 2 (EU 2 & EU 2G)
IA		85-01-006	City of Ames - Steam Electric Plant	Boiler #7 (EU 2)
IA		29-01-013	Interstate Power & Light - Burlington	Main Plant Boiler.
IA		03-03-001	Interstate Power & Light - Lansing	Boiler #4. Sixteen units in total.
IA		23-01-014	Interstate Power & Light - ML Kapp	Boiler #2. Six units in total.
IA		57-01-042	Interstate Power & Light - Prairie Creek	Boiler #4. Fourteen units in total.
IA		78-01-026	MidAmerican Energy Co - Council Bluffs	Boiler #3 (EU003)
IA		97-04-010	MidAmerican Energy Co - Neal North	Boilers #1-3 (EU001 - EU003)
IA		97-04-011	MidAmerican Energy Co - Neal South	Boiler #4 (EU003)
IA		70-01-011	Muscatine Power and Water	Boiler #8
IA		63-02-005	Pella Municipal Power Plant	Boilers #6-8
MN		2709900001	Austin Utilities NE Power Station	EU001
MN		2713700027	Hibbing Public Utilities	EU003
MN		2703100001	MN Power, Taconite Harbor	EU003
MN		2706100004	MN Power, Boswell Energy Center	EU003
MN		2701500010	New Ulm Public Utilities	EU003 - Boiler 4
MN		2711100002	Otter Tail Power Hoot Lake	EU003
MN		2710900011	Rochester Public Utilities, Silver Lake	EU003
MN		2710900011	Rochester Public Utilities, Silver Lake	EU004
MN		2713700028	Virginia Public Utilities	EU003 - Boiler 9
MN		2714100004	Xcel Energy, Sherco	EU001, EU002
MN		2716300005	Xcel Energy, Allen S King	EU001 - Boiler 1

MN		2705300015	Xcel Energy, Riverside	EU003 - Boiler 8
MO		290710003	Ameren -Labadie	B1, B2, B3, B4
MO		291830001	Ameren - Sioux	B1, B2
MO		290990016	Ameren - Rush Island	B1, B2
MO		290950031	Auila - Sibley	B3 - 5C
MO		291430004	Assoc. Electric - New Madrid	B1(EP-01), B2 (EP-02)
MO		290770039	City Utilities Springfield - Southwest	B1 (E09)
MO		290770005	City Utilities Springfield - James River	EO7, EO8
MO		290970001	Empire Distric Electric - Asbury	B7
MO		290830001	KC Power and Light - Montrose	EP08
MO		290210004	Aqula - Lake Road	EP06
MO		291750001	Assoc. Electric - Thomas Hill	EP01, EP02
MO		290950021	Trigen - Kansas City	B1A
MO		290190002	City of Columbia Municipal Power Plant	EP02
MO		291950010	Marshall Munipal Utilities	EP05
MO		290950050	Independence Power & Light-Blue Valley	B3 (EP05)
WV		3943	Fort Martin	
WV		6004	Pleasants	
WV		3948	Mitchell	
WV		3935	Amos	
WV		6264	Mountaineer	
WV		3944	Harrison	
TN		3396	TVA Bull Run	
TN		3399	TVA Cumberland	
KY		1363	Cane Run	
KY		1364	Mill Creek	
KY		6041	Spurlock	
KY		1384	John Sherman Cooper	
KY		1353	Big Sandy	
KY		1356	Ghent	
KY		1355	Brown	
KY		1374	Owensboro Municipal	
KY		1372	Henderson Municipal	
KY		1378	Paradise	
KY		1361	Coleman	
KY		1382	Reid/Henderson 2	
KY		6639	Green	

Public Notice
Ohio Environmental Protection Agency
Redesignation and Maintenance Plan for the Ohio Portion of the Cincinnati-Hamilton, OH-KY-IN Annual $PM_{2.5}$ Nonattainment Area

Butler, Clermont, Hamilton, and Warren Counties

Notice is hereby given that the Director of the Ohio Environmental Protection Agency, (Ohio EPA) is requesting that the United States Environmental Protection Agency (U.S. EPA) revise the current air quality designation for the Ohio portion of the Cincinnati-Hamilton area, including Butler, Clermont, Hamilton, and Warren counties to attainment with respect to the 1997 annual $PM_{2.5}$ national ambient air quality standard (NAAQS). Air quality monitoring data collected between 2007 and 2009 in the region demonstrate attainment of the NAAQS and there is evidence that the improved air quality is due to permanent, enforceable emission reductions. In addition, existing requirements are sufficient to maintain the 1997 annual $PM_{2.5}$ standard in this area at least ten years into the future.

Computer models show that existing state and federal emission reduction requirements are sufficient to attain and maintain the NAAQS in the Cincinnati-Hamilton area. Therefore, Ohio EPA proposes to utilize existing emission inventory information and projections of future emissions as the demonstration of the ability to maintain the NAAQS in the Cincinnati-Hamilton area in the future.

The Cincinnati-Hamilton area is currently designated as nonattainment for the 1997 annual $PM_{2.5}$ standard. As part of an acceptable maintenance plan, Ohio EPA is required to develop a contingency plan to provide for additional emission reductions if a violation of the NAAQS is monitored after the area has been redesignated. The plan which Ohio EPA is proposing to USEPA as part of this redesignation contains reductions which will help alleviate the ambient problem until a revised SIP can be developed.

The State of Ohio proposes to:

1. Request the U.S. EPA redesignate the Cincinnati-Hamilton area to attainment with respect to the 1997 annual $PM_{2.5}$ NAAQS and revise the maintenance plan. This request will document that existing enforceable control measures are responsible for the observed improvement in air quality.

2. Designate existing controls as sufficient to maintain the NAAQS into the future.

3. Commit to the proposed contingency plan.

These actions must be noticed to allow public comment and to satisfy USEPA requirements for public involvement in SIP related activities. This notice addresses Ohio

EPA's reliance on the emission projections as evidence of attainment and maintenance and the commitment to institute contingency measures if ambient exceedances or violations trigger the contingency plan requirements. Written comments will be received on or before November 29, 2010 at the following address:
E-mail: Carolina.Prado@epa.state.oh.us

Mailing address: Carolina Prado
Ohio Environmental Protection Agency, DAPC
Lazarus Government Center
P.O. Box 1049
Columbus, Ohio 43216-1049
Phone: (614)- 728-1743

Pursuant to Section 119.03 of the Ohio Revised Code, a public hearing on this redesignation request will be conducted as follows: November 29, 2010 at 2:30 P.M., at Hamilton County Department of Environmental Services located at 250 William Howard Taft Road, Cincinnati, Ohio.

All interested persons are entitled to attend or be represented at the hearings and give written or oral comments on these changes. All oral comments presented at the hearing, and all written statements submitted at the hearing or to the above address by the close of business on November 30, 2010 will be considered by Ohio EPA prior to final action on this redesignation. Written statements submitted after November 30, 2010 may be considered as time and circumstances permit, but will not be part of the official record of the hearing.

This redesignation and maintenance request is available on Ohio EPA DAPC's Web page for electronic downloading. The URL is: http://www.epa.ohio.gov/dapc/SIP/annual.aspx. Questions regarding accessing the web site should be directed to Arunee Niamlarb at 614-728-1342; other questions or comments about this document should be directed to either Carolina Prado, (614)-644-2310, Carolina.Prado@epa.state.oh.us or Jennifer Hunter at (614) 644-3696, Jennifer.Hunter@epa.state.oh.us or mailed to Carolina Prado or Jennifer Hunter at the above address.

ENVIRONMENTAL PROTECTION AGENCY

PUBLIC HEARING

IN THE MATTER OF:

OHIO EPA REQUESTS

RECOGNITION OF IMPROVED

AIR QUALITY IN CINCINNATI

PUBLIC HEARING HELD AT THE HAMILTON COUNTY DEPARTMENT OF ENVIRONMENTAL SERVICES, 250 WILLIAM HOWARD TAFT ROAD, CINCINNATI, OHIO, ON MONDAY, NOVEMBER 29, 2010, BEGINNING AT 2:37 P.M., REPORTED BY MARY A. SCHWEINHAGEN, RPR, RMR, AND CRR.

MS. MCCARRON: My name is Mary McCarron. I am the public involvement coordinator, and I'll be presiding over the hearing today.

Thank you for taking the time to attend this hearing. It's to gather any comments from interested parties regarding Ohio EPA's proposed action.

Ohio EPA is planning to ask U.S. EPA to revise the current air quality designation for the Ohio portion of the Cincinnati-Hamilton area to attainment with respect to the 1997 annual PM2.5 national ambient air quality standard. The proposed redesignation request affects Butler, Clermont, Hamilton, and Warren counties.

Comments can be submitted until the close of business on November 30th, 2010, to Carolina Prado at Carolina.prado@epa.ohio.gov.

All interested persons are entitled to attend or to be represented and to present oral and/or written comments concerning the proposed action. All written and oral comments received as part of the official record will be considered by the director of Ohio EPA.

To be included in the official record, written comments must be received, as I

said earlier, by November 30th, 2010. These comments can be filed with me today or e-mailed to the address mentioned earlier. All written comments submitted for the record receive the same consideration as any oral testimony given today.

Written comments submitted after November 30th may be considered as time and circumstances permit but won't be part of the official record.

At this point I am going to read the names of the folks who have registered at the hearing today, and if you don't want to speak just go ahead and say pass.

The first person who registered is Dick Brewer.

MR. DICK BREWER: Pass.

MS. MCCARRON: And Andy Reser?

MR. ANDY RESER: Pass.

MS. MCCARRON: I think at this point there is nobody else who is signed in to present testimony, and so we will go off the record until 3 p.m.

(WHEREUPON, the parties went off the record.)

MS. MCCARRON: At this time is

there anybody else who would wish to testify for the hearing? Okay. Seeing none, we are going to go ahead and close out this hearing.

I remind you that written comments can be submitted through November 30th.

The time is now 3:06, and this hearing is adjourned.

(Hearing adjourned at 3:06 p.m.)

C E R T I F I C A T E

I, Mary A. Schweinhagen, a Registered Merit Reporter and Certified Realtime Reporter do hereby certify that the foregoing is a full, true and correct transcript of my notes taken in the above-styled case and thereafter transcribed by me.

Mary A. Schweinhagen, RMR, CRR

Division of Air Pollution Control

Response to Comments
$PM_{2.5}$ redesignation request for the 1997 $PM_{2.5}$ Annual Standard for the Cincinnati-Hamilton Area

Agency Contact for this Package

Division Contact: (Carolina Prado, Division of Air Pollution Control, 614-644-2310, Carolina.Prado@epa.state.oh.us)

Ohio EPA held a public hearing in Cincinnati, OH on November 29, 2010, regarding the Redesignation Request and Maintenance Plan for the Cincinnati-Hamilton $PM_{2.5}$ Nonattainment Area. This document summarizes the comments and questions received at the public hearing and during the associated comment period, which ended on November 30, 2010. Ohio EPA reviewed and considered all comments received during the public comment period.

By law, Ohio EPA has authority to consider specific issues related to protection of the environment and public health.

In an effort to help you review this document, the questions are grouped by topic and organized in a consistent format. The name of the commenter follows the comment in parentheses.

General/Overall Concerns

Comment 1: **The final submission should include electronic copies of the RunSpec files, the user-supplied input database(s), and the output databases(s) produced for the analysis. The inclusion of post-processing scripts in Section 4.6 and 5 is very helpful (Patricia Morris, U.S. EPA - Region 5).**

Response 1: The RunSpec files, input and output databases, SQL post-processing scripts, and the revised documentation have been saved to CDs and 2 copies will be provided to U.S. EPA.

Comment 2: **Table 3 in the unnumbered section at the beginning of the document includes a summary of the RunSpec parameters used in this analysis. The Appendix, which starts on numbered page 11, includes a more detailed description of the RunSpec parameters and user inputs. There are some discrepancies between Table 3 and the Attachment text**

which are listed in order below (Patricia Morris, U.S. EPA – Region 5).

Response 2: The text discrepancies between Table 3 and Appendix C have been corrected as indicated.

Comment 3: **The default database version listed in Table 3 ("MOVES default database 2010615111524") does not exist. The documentation needs to accurately refer to the version of the database used (Patricia Morris, U.S. EPA – Region 5).**

Response 3: We have correctly identified the version in the final document.

Comment 4: **For calculating annual $PM_{2.5}$ emissions, OKI used a single daily temperature profile that was based on annual average temperatures (Table 3 and Section 1.3). PM emissions in MOVES are sensitive to temperature, and the use of a single day temperature profile to represent the entire year may not accurately reflect the impact of seasonal temperature changes on PM emissions form motor vehicles. For a PM inventory that is going to be used for air quality modeling in an attainment demonstration, seasonal, monthly, or even daily temperatures may be needed, depending on the detailed circumstances of the analysis. Given that this analysis is not being used for an attainment demonstration, the use of an average annual temperature profile is acceptable, but approval of this approach should be taken as a general approval of the use of a single daily temperature profile for all uses (Patricia Morris, U.S. EPA - Region 5).**

Response 4: It is our understanding that the use of one set of annual averages is acceptable for developing a motor vehicle emissions budget and for transportation conformity. This methodology is similar to what OKI used for MOBILE. We agree that MOVES assumptions used for different state implementation purposes may need to vary. OKI will be experimenting with a four season approach to annual emissions. When MOVES is used for attainment demonstrations purposes we will discuss further the appropriate assumptions to use with all parties involved.

Comment 5: **Section 1.3 of the Appendix says, "Ozone season daily analysis is done using July temperatures." What is the purpose of this analysis in the context of this submission?**

There doesn't seem to be any other reference to this in the document (Patricia Morris, U.S. EPA - Region 5).

Response 5: OKI's MOVES runs generated additional information (i.e. July emission rates) that was not required for this PM2.5 SIP. Document references to an ozone season analysis and July temperatures have been deleted.

Comment 6: **Table 3 says that all roads types including off-network were included. Section 1.6 says, "There are five types of road types available in MOVES, since OKI travel demand model could not predict the VMT in parking lots (off network) only four road types is used to assign activity for vehicles starts and for evap emissions while vehicles are parked. It does not apply to VMT parking lots. Given that start emissions were calculated, the entry in Table 3 seems to be the correct one, but the document should be clarified (Patricia Morris, U.S. EPA - Region 5).**

Response 6: We have included the appropriate clarification in the final document.

Comment 7: **Table 3 says that all PM2.5 categories were selected in the Pollutants and Processes panel, but Section 1.7 says that "total PM2.5 emissions are selected in addition of (sic) sulfur dioxide." If that is accurate, the inventory would not include brake-wear and tire-wear emissions which are calculated separately from "Total PM2.5" which only includes exhaust emissions. Given that the inventories include brake and tire wear, Table 3 seems to have the correct information, but the documentation should be clarified (Patricia Morris, U.S. EPA - Region 5).**

Response 7: We have included the appropriate clarification in the final document.

Comment 8: **Table 3 and Section 2.2 indicate that for the Ohio counties, local populations were used for all source types except 41, 61, and 62. However, in the Kentucky counties, default data were also used for the light truck categories (31 - passenger trucks and 32- light commercial trucks). We are concerned about the use of default data for the light truck categories. Our technical guidance is very clear on the importance of**

local information for source type population. While it may be reasonable to use national defaults for some of the heavy duty categories as was done in the Ohio counties, OKI should be able to develop local data for the light duty categories. If Kentucky has local data for passenger cars, they should also have local data for light trucks (Patricia Morris, U.S. EPA - Region 5).

Response 8: The Kentucky Transportation Cabinet (KYTC) decoded VINs and provided the results by HPMS source type to OKI. Inconsistencies were found in the results and could not be corrected in time for OKI's analysis. It was decided that a combination of the KYTC VIN data and MOVES default data would provide the most accurate results. KYTC continues to try to correct the VIN decoding errors.

End of comments

LEGAL NOTICE OF PUBLIC HEARING

Redesignation Petition and Maintenance Plan
In Association with the Annual Fine Particle ($PM_{2.5}$) Standard

Lawrenceburg Township, Dearborn County, Indiana

Notice is hereby given under 40 CFR 51.102 that the Indiana Department of Environmental Management (IDEM) will hold a public hearing on January 5, 2011. The purpose of this hearing is to receive public comment on the Draft Redesignation Petition and Maintenance Plan in association with the Annual Fine Particle ($PM_{2.5}$) Standard, for Lawrenceburg Township, Dearborn County, Indiana. The meeting will convene at 5:30 p.m. (local time) at the Lawrenceburg Public Library, Ewbank Meeting Room 1 and 2, 150 Mary Street, Lawrenceburg, Indiana 47025. All interested persons are invited and will be given opportunity to express their views concerning the draft documents.

Lawrenceburg Township, Dearborn County, Indiana is part of the Cincinnati-Hamilton OH-KY-IN Fine Particle Nonattainment Area. This area was designated as nonattainment for the annual fine particle standard and subject to the requirements of Section 172 of the Clean Air Act (CAA). One of the compliance requirements mandated by Section 172(c) of the CAA, is the development of a plan demonstrating that the area will continue to meet the annual standard for fine particles. This Redesignation Petition and Maintenance Plan is being drafted and submitted consistent with United States Environmental Protection Agency (U.S. EPA) guidance.

Copies of the draft documents will be available on or before December 5, 2010 to any person upon request and at the following locations:

- Indiana Department of Environmental Management, Office of Air Quality, Indiana Government Center North, 100 North Senate, Room N1003, Indianapolis, Indiana.
- Lawrenceburg Public Library, 150 Mary Street, Lawrenceburg, Indiana.
- Lawrenceburg City Building, 230 Walnut Street, Lawrenceburg, Indiana.

The draft documents will also be available on the following Web page:

http://www.in.gov/idem/4658.htm

Oral statements will be heard, but for the accuracy of the record, statements should be submitted in writing. Written statements may be submitted to the attendant designated to receive written comments at the public hearing.

IDEM will also accept written comments through January 7, 2010. Mailed comments should be addressed to:

Lawrenceburg Township, Dearborn County, Indiana Fine Particle ($PM_{2.5}$) Redesignation Petition and Maintenance Plan
Scott Deloney, Chief
Programs Branch
Indiana Department of Environmental Management
Office of Air Quality MC 61-50
100 North Senate Avenue
Indianapolis, IN 46206-2251

A transcript of the hearing and all written submissions provided at the public hearing shall be open to public inspection at IDEM and copies may be made available to any person upon payment of reproduction costs. Any person heard or represented at the hearing or requesting notice shall be given written notice of actions resulting from the hearing.

For additional information contact Ms. Sarah Raymond, at the Indiana Department of Environmental Management, Air Programs Branch, Office of Air Quality, Room 1001, Indiana Government Center North, 100 North Senate Avenue, Indianapolis or call (317) 232-8449 or (800) 451-6027 ext. 2-8449 (in Indiana).

****

Individuals requiring reasonable accommodations for participation in this hearing should contact the IDEM Americans with Disabilities Act (ADA) coordinator at:

Attn: ADA Coordinator
Indiana Department of Environmental Management – Mail Code 50-10
100 North Senate Avenue
Indianapolis, IN 46204-2251

Or call (317) 233-1785 (voice) or (317) 232-6565 (TDD). Please provide a minimum of 72 hours notification.

REQUEST FOR REDESIGNATION AND MAINTENANCE PLAN UNDER THE ANNUAL NATIONAL AMBIENT AIR QUALITY STANDARD FOR FINE PARTICLES

For the Indiana Portion
of the

Cincinnati – Hamilton, OH-KY-IN
Nonattainment Area for Fine Particles

Lawrenceburg Township, Dearborn County, Indiana

Prepared By:
The Indiana Department of Environmental Management

November 2010

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CINCINNATI-HAMILTON OH-KY-IN AREA

1.0 INTRODUCTION

This document supports Indiana's request that Lawrenceburg Township in Dearborn County, Indiana, which is part of the Cincinnati-Hamilton OH-KY-IN fine particles nonattainment area (herein referred to as the Cincinnati area), be redesignated from nonattainment to attainment of the 1997 annual standard for fine particles. There are no monitors for fine particles in the Indiana portion of the Cincinnati area. However, because the Cincinnati area has recorded three years of quality assured ambient air quality monitoring data for the years 2007 through 2009, demonstrating attainment with the annual standard for fine particles, the Indiana portion of the Cincinnati area is eligible for redesignation.

Section 107 of the Clean Air Act (CAA) establishes specific requirements to be met in order for an area to be considered for redesignation, including:

(a) A determination that the area has attained the annual standard for fine particles.
(b) An approved State Implementation Plan (SIP) for the area under Section 110(k).
(c) A determination that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the SIP and other federal requirements.
(d) A fully approved maintenance plan under Section 175A.
(e) A determination that all Section 110 and Part D requirements have been met.

A maintenance plan provides for the continued attainment of the air quality standard by an area for a period of ten years after the United States Environmental Protection Agency (U.S. EPA) has formally redesignated the area to attainment. The plan also provides assurances that even if there is a subsequent exceedance of the air quality standard, measures in the maintenance plan will prevent any future occurrences through contingency measures that would be triggered.

This document addresses each of these requirements, and provides additional information to support continued compliance with the annual standard for fine particles.

1.1 Background

The CAA requires states with areas designated nonattainment of the applicable National Ambient Air Quality Standard (NAAQS) for particulate matter to develop SIPs to expeditiously attain and maintain the standard. In 1997, U.S. EPA set daily and annual air quality standards for fine particles ($PM_{2.5}$), as shown in Table 1.1. The standards were legally challenged and upheld by the U.S. Supreme Court in February of 2001. In 1999, Indiana began monitoring for

fine particle concentrations. The U.S. EPA designated areas in Indiana under the fine particle standards on December 17, 2004, as attainment, nonattainment, or unclassifiable, with an effective date of April 5, 2005.

Table 1.1
National Ambient Air Quality Standards for Fine Particles

	Annual	24-Hour
1997 Fine Particles Standard ($PM_{2.5}$)	**15 µg/m^3** Annual arithmetic mean, averaged over three years	**65 µg/m^3** 24-hour average, 98th percentile, averaged over three years
2006 Fine Particles Standard ($PM_{2.5}$)	**15 µg/m^3** Annual arithmetic mean, averaged over three years	**35 µg/m^3** 24-hour average, 98th percentile, averaged over three years

Note: The Cincinnati area meets the 1997 and 2006 24-hour NAAQS for fine particles. Since this area is solely designated nonattainment under the 1997 annual standard for fine particles, this document only addresses the annual standard.

On December 17, 2004, based on 2001 through 2003 monitoring data, U.S. EPA designated the Cincinnati-Hamilton OH-KY-IN area as nonattainment of the annual standard for fine particles, and subject to CAA, Part D, Title 1, Section 172 of Subpart 1 requirements, including the development of a plan to reduce nitrogen oxides (NO_x), sulfur dioxide (SO_2), and direct $PM_{2.5}$ emissions and a demonstration that the area will meet the annual standard for fine particles by April 5, 2010. In order to satisfy these requirements, Indiana submitted an attainment demonstration to U.S. EPA on April 3, 2008, demonstrating that with the combination of clean air measures and the implementation of local and federally required control measures, air quality in the nonattainment area would meet the annual NAAQS for fine particles by April 5, 2010, and provide for an ample margin of safety. The Cincinnati-Hamilton OH-KY-IN area monitors have met the annual NAAQS for fine particles since the end of 2009.

There were no monitors in the Cincinnati-Hamilton OH-KY-IN fine particles nonattainment area that violated the 1997 24-hour standard for fine particles and or currently violates the 2006 24-hour standard for fine particles. As a result, the Cincinnati-Hamilton OH-KY-IN fine particles nonattainment area was designated nonattainment solely under the 1997 annual standard. Therefore, this document pertains only to the 1997 annual standard for fine particles.

The Cincinnati-Hamilton OH-KY-IN fine particles nonattainment area, as defined in Section 1.2, has not previously been subject to nonattainment area rulemakings for fine particles. However, the area had been subject to nonattainment area rulemakings under the 1-hour and the 8-hour ozone standards. The 1-hour ozone standard was revoked on June 15, 2005, and the Cincinnati area was redesignated to attainment of the 1997 ozone standard on May 11, 2010.

1.2 Geographical Description

The entire Cincinnati fine particles nonattainment area consists of: Lawrenceburg Township in Dearborn County, Indiana; Butler, Clermont, Hamilton, and Warren counties, Ohio; Boone, Campbell, and Kenton counties, Kentucky; and contains such cities as Cincinnati, Hamilton, and

Middletown, all in Ohio. This area is depicted in Figure 3.1.

The agencies responsible for assuring the fine particles nonattainment area complies with the CAA requirements are:

- The Ohio Environmental Protection Agency (Ohio EPA), which is responsible for Butler, Clermont, Clinton, Hamilton, and Warren counties, Ohio.
- The Kentucky Department for Environmental Protection, (KDEP) which is responsible for Boone, Campbell, and Kenton counties, Kentucky.
- The Indiana Department of Environmental Management (IDEM), which is responsible for Lawrenceburg Township, Dearborn County, Indiana.

These three state agencies have worked cooperatively with U.S. EPA Regions IV and V to address attainment planning issues.

Although the three agencies, in the three states, have worked together on a comprehensive plan for the multi-state nonattainment areas, each state is required to make a separate submittal for its portion of the planning components to U.S. EPA. Attainment demonstrations are SIP submittals and U.S. EPA action on them is taken separately. As such, this submittal only covers Lawrenceburg Township in Dearborn County, Indiana.

1.3 Status of Air Quality

Monitoring data for fine particles for the three years, 2007 through 2009, demonstrates that air quality has met the annual NAAQS for fine particles in the Cincinnati area. This fact, accompanied by the permanent and enforceable reductions in emission levels discussed in Section 4.0, justifies a redesignation to attainment for the Indiana portion of the Cincinnati-Hamilton, OH-KY-IN nonattainment area based on Section 107(d)(3)(E) of the CAA.

2.0 REQUIREMENTS FOR REDESIGNATION

2.1 General

Section 110 and Part D of the CAA list a number of requirements that must be met by nonattainment areas prior to consideration for redesignation to attainment. In addition, U.S. EPA has published detailed guidance in a document entitled *Procedures for Processing Requests to Redesignate Areas to Attainment*, issued September 4, 1992, to Regional Air Directors. This document is hereafter referred to as "Redesignation Guidance." This Request for Redesignation and Maintenance Plan is based on the Redesignation Guidance, supplemented with additional guidance received from staff of the Air Planning and Maintenance Section of U.S. EPA Region V. The specific requirements for redesignation are listed below.

2.2 Fine Particles Monitoring

1) A demonstration that the annual standard for fine particles, as published in 40 CFR 50.13, has been attained. Fine particles monitoring data must show that violations of the annual ambient standard are no longer occurring.

2) Ambient monitoring data quality assured in accordance with 40 CFR 58.15, recorded in the U.S. EPA Air Quality System (AQS) database, and available for public view.

3) A showing that the three-year average of annual values, based on data from all monitoring sites in the area or its affected downwind environs, do not exceed 15.0 micrograms per cubic meter ($\mu g/m^3$). This showing must rely on three complete, consecutive calendar years of quality assured data.

4) A commitment that, once redesignated, the state will continue to operate an appropriate monitoring network to verify the maintenance of the standard.

2.3 Emission Inventory

1) A comprehensive emission inventory of direct $PM_{2.5}$ and the precursors of fine particles completed for the base year (2008 in this case).

2) A projection of the emission inventory to a year at least ten years following redesignation.

3) A demonstration that the projected level of emissions is sufficient to maintain the annual standard for fine particles.

4) A demonstration that improvement in air quality between the year violations occurred and the year attainment was achieved is based on permanent and enforceable emission reductions and not on temporary adverse economic conditions or unusually favorable meteorology.

5) Provisions for future annual updates of the inventory to enable tracking of the emission levels, including an annual emission statement from major sources.

2.4 Modeling Demonstration

While no modeling is required for redesignating nonattainment areas, IDEM has evaluated the results of federal control-case modeling to demonstrate that compliance with the standard will be maintained.

2.5 Controls and Regulations

1) A U.S. EPA-approved SIP control strategy that includes Reasonably Available Control Technology (RACT) requirements for existing stationary sources covered by Control Technology Guidelines (CTG) and non-CTG RACT for all major sources.

2) Evidence that control measures required in past SIP revisions have been fully implemented.

3) Acceptable provisions to provide for new source review.

4) Assurances that existing controls will remain in effect after redesignation, unless the state demonstrates through photochemical modeling that the standard can be maintained without one or more controls.

5) If appropriate, a commitment to adopt a requirement that all transportation plans conform with and are consistent with the SIP.

2.6 Corrective Actions for Potential Future Violations of the Fine Particles Standard

1) A commitment to submit a revised plan eight years after redesignation.

2) A commitment to expeditiously enact and implement additional contingency control measures in response to exceeding specified predetermined levels (triggers) or in the event that future violations of the ambient standard occur.

3) A list of potential contingency measures that would be implemented in such an event.

4) A list of Nitrogen Oxides (NO_x), Sulfur Dioxide (SO_2) and direct $PM_{2.5}$ sources potentially subject to future controls.

3.0 FINE PARTICLES MONITORING

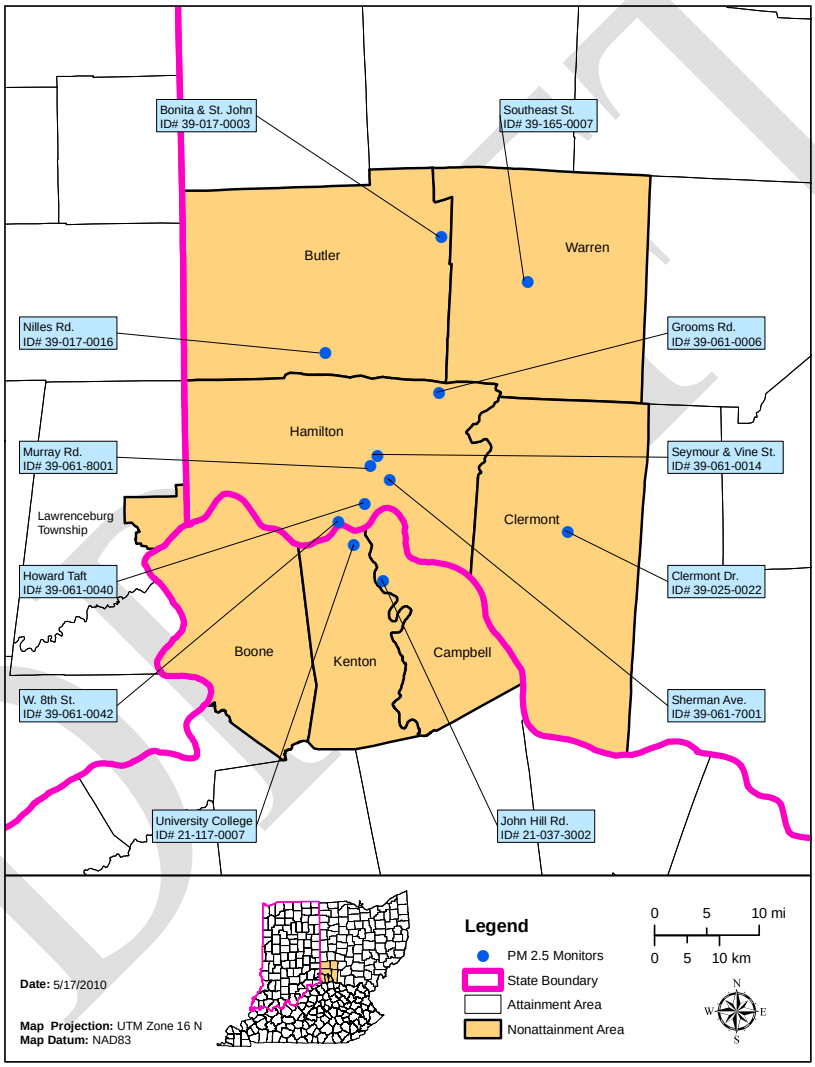
3.1 Fine Particles Monitoring Network

There are currently 12 Federal Reference Method monitors measuring fine particle concentrations for the Cincinnati area. Fine particle monitors are located in Campbell and Kenton counties in Kentucky and Butler, Clermont, Warren, and Hamilton counties in Ohio. There are no monitors for fine particles in the Indiana portion of the Cincinnati nonattainment area. The highest levels of fine particle concentrations have been typically monitored at the Seymour and Vine Street monitor (39-0061-0014) in Hamilton County, Ohio. The locations of the monitoring sites for the Cincinnati area are shown in Figure 3.1. A listing of the monitor readings from 2007 through 2009, is shown in Table 3.1 and Appendix A. The monitor readings

were retrieved from the U.S. EPA's Air Quality System (AQS).

The Wilwood and Winneste Ave. monitors in Ohio were discontinued on December 31, 2005. The Alexandria Park monitor in Kentucky was discontinued on December 31, 2006. The Hook Field Airport monitor in Ohio was discontinued on December 31, 2007. Therefore, these discontinued monitors are not shown in Figure 3.1.

Figure 3.1
Cincinnati Basic Nonattainment Area



3.2 Ambient Fine Particles Monitoring Data

The following information summarizes U.S. EPA's "Guideline on Data Handling Conventions for the annual fine particles NAAQS," U.S. EPA-454/R-99-008, April 1999. Three complete years of fine particles monitoring data are required to demonstrate attainment at a monitoring site. The annual ambient air quality standard for fine particles is met at an ambient air quality monitoring site when the three-year average of the annual average of fine particle concentrations is less than or equal to 15.0 $\mu g/m^3$. When this occurs, the site is said to be in attainment. While calculating design values, three significant digits must be carried in the computations, with final values rounded to the nearest 0.1 $\mu g/m^3$. Decimals 0.05 or greater are rounded up, and those less than 0.05 are rounded down, so that 15.049 $\mu g/m^3$ is the largest concentration that is less than or equal to 15.0 $\mu g/m^3$. Values at or below 15.0 $\mu g/m^3$meet the standard. Values equal to or greater than 15.1 $\mu g/m^3$ exceed the standard.

Data handling procedures are applied on an individual basis at each monitor in the area. An individual site's three-year average of the annual average fine particles concentration is also called the site's *design value*. An area is in compliance with the annual NAAQS for fine particles only if all monitoring sites meet the NAAQS. The air quality design value for the area is the highest design value among all sites in the area. Table 3.1 shows the annual fine particle values by site and the 2007 through 2009 design values for the 12 active fine particle monitoring sites in the Cincinnati area.

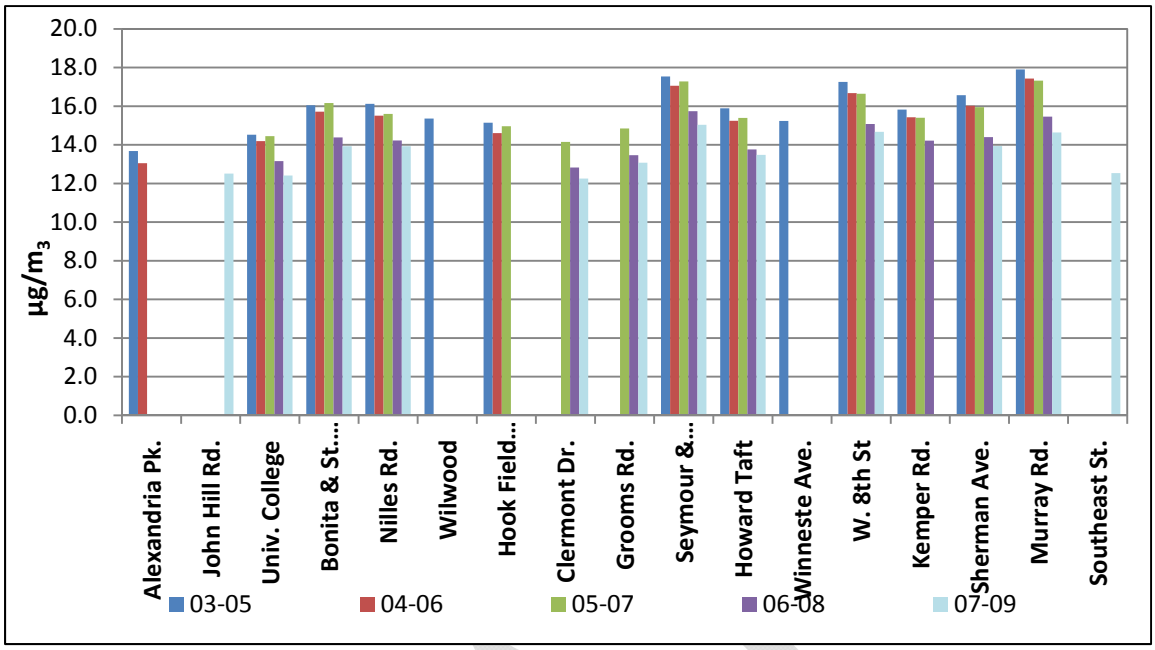
Table 3.1
Monitoring Data for the Cincinnati Area (Annual Average and 2007-2009 Design Values)

SITE ID	STATE	COUNTY	SITE NAME	YEAR	Annual Average ($\mu g/m^3$)	2007-2009 Average ($\mu g/m^3$)
21-037-3002	Kentucky	Campbell	John Hill Rd.	2007	14.36	
21-037-3002	Kentucky	Campbell	John Hill Rd.	2008	11.83	
21-037-3002	Kentucky	Campbell	John Hill Rd.	2009	11.34	**12.51**
21-117-0007	Kentucky	Kenton	Univ. College	2007	14.20	
21-117-0007	Kentucky	Kenton	Univ. College	2008	11.99	
21-117-0007	Kentucky	Kenton	Univ. College	2009	11.04	**12.41**
39-017-0003	Ohio	Butler	Bonita & St. John	2007	15.41	
39-017-0003	Ohio	Butler	Bonita & St. John	2008	13.69	
39-017-0003	Ohio	Butler	Bonita & St. John	2009	12.68	**13.93**
39-017-0016	Ohio	Butler	Niles Rd.	2007	14.94	
39-017-0016	Ohio	Butler	Niles Rd.	2008	13.75	
39-017-0016	Ohio	Butler	Niles Rd.	2009	13.08	**13.92**
39-017-1004	Ohio	Butler	Hook Fld. Airport	2007	14.63	
39-017-1004	Ohio	Butler	Hook Fld. Airport	2008		
39-017-1004	Ohio	Butler	Hook Fld. Airport	2009		**N/A**
39-025-0022	Ohio	Clermont	Clermont Dr.	2007	14.01	
39-025-0022	Ohio	Clermont	Clermont Dr.	2008	11.75	
39-025-0022	Ohio	Clermont	Clermont Dr.	2009	11.01	**12.26**

39-061-0006	Ohio	Hamilton	Grooms Rd.	2007	14.63	
39-061-0006	Ohio	Hamilton	Grooms Rd.	2008	12.48	
39-061-0006	Ohio	Hamilton	Grooms Rd.	2009	12.11	**13.07**
39-061-0014	Ohio	Hamilton	Seymour & Vine St.	2007	16.59	
39-061-0014	Ohio	Hamilton	Seymour & Vine St.	2008	15.12	
39-061-0014	Ohio	Hamilton	Seymour & Vine St.	2009	13.40	**15.04**
39-061-0040	Ohio	Hamilton	Howard Taft	2007	15.09	
39-061-0040	Ohio	Hamilton	Howard Taft	2008	12.62	
39-061-0040	Ohio	Hamilton	Howard Taft	2009	12.73	**13.48**
39-061-0042	Ohio	Hamilton	W. 8th St.	2007	15.90	
39-061-0042	Ohio	Hamilton	W. 8th St.	2008	14.40	
39-061-0042	Ohio	Hamilton	W. 8th St.	2009	13.71	**14.67**
39-061-0043	Ohio	Hamilton	Kemper Rd.	2007	14.85	
39-061-0043	Ohio	Hamilton	Kemper Rd.	2008	13.32	
39-061-0043	Ohio	Hamilton	Kemper Rd.	2009		**N/A**
39-061-7001	Ohio	Hamilton	Sherman Ave.	2007	15.09	
39-061-7001	Ohio	Hamilton	Sherman Ave.	2008	13.74	
39-061-7001	Ohio	Hamilton	Sherman Ave.	2009	12.97	**13.93**
39-061-8001	Ohio	Hamilton	Murray Rd.	2007	16.07	
39-061-8001	Ohio	Hamilton	Murray Rd.	2008	14.40	
39-061-8001	Ohio	Hamilton	Murray Rd.	2009	13.44	**14.64**
39-165-0007	Ohio	Warren	Southeast St.	2007	13.98	
39-165-0007	Ohio	Warren	Southeast St.	2008	11.92	
39-165-0007	Ohio	Warren	Southeast St.	2009	11.70	**12.53**
Value Above the Annual $PM_{2.5}$ Standard						

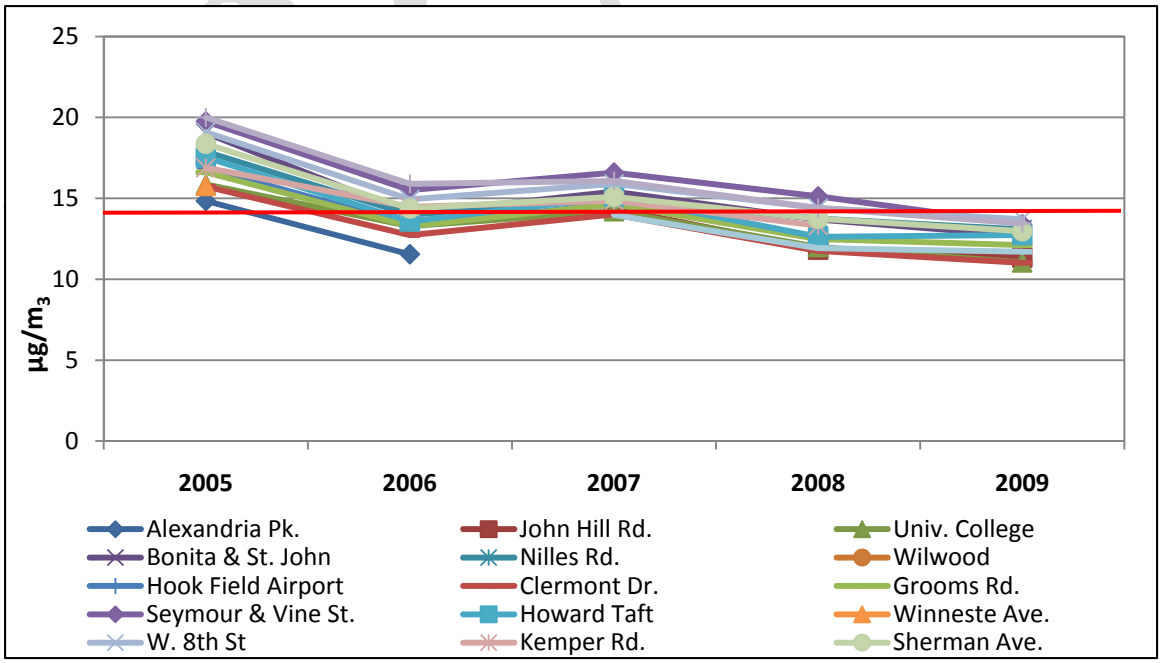
Graph 3.1 visually demonstrates the 2003 through 2009 design values for the Cincinnati area.

Graph 3.1
Design Values for the Cincinnati Area for Fine Particles, 2003 through 2009



Note: The AlexandriaPark monitor in Kentucky was discontinued on December 31, 2006. The Wilwood and Winneste Ave. monitors in Ohio were discontinued on December 31, 2005. The Hook Field Airport monitor in Ohio was discontinued on December 31, 2007.

Graph 3.2
Cincinnati Area Annual Fine Particles Trends, 2005 through 2009



Note: The Alexandria Park monitor in Kentucky was discontinued on December 31, 2006. The Wilwood and Winneste Ave. monitors in Ohio were discontinued on December 31, 2005. The Hook Field Airport monitor in Ohio was discontinued on December 31, 2007.

The design values for the Cincinnati area demonstrate that the annual NAAQS for fine particles has been attained. Refer to Appendix A for the complete fine particles monitoring data summary for the years 2000 to 2009.

Graph 3.1 shows the trend in design values, while Graph 3.2 shows the trend for annual fine particles. A comprehensive list of the fine particles monitoring sites' design values over this period is outlined in Appendix A. The area's design values have recently trended downward, as emissions have declined due to programs such as the Acid Rain program and cleaner automobiles and fuels both regionally and locally. U.S. EPA's rule to control nitrogen oxides from specific source categories (40 CFR Parts 51, 72, 75 and 96, published on October 17, 1998 and referred to as the "NO_x SIP Call") has significantly reduced emissions from large electric generating units (EGUs), industrial boilers, and cement kilns. Indiana's NO_x SIP Call Rule was adopted into the Indiana Administrative Code on June 6, 2001 at 326 IAC 10-3 and 326 ICA 10-4. The elevated fine particle values for 2005 are considered an abnormal occurrence. An analysis of meteorological conditions and monitoring values is included in Section 7.0 and supports the conclusion that attainment of the standard as of 2009 is not the result of unusually favorable meteorological conditions. It is expected that this downward trend will continue as the above programs continue and the U.S. EPA's proposed Transport Rule is implemented.

3.3 Quality Assurance

Kentucky and Ohio have quality assured all data shown in Appendix A in accordance with 40 CFR 58.10 and recorded the data in the AQS database and, thus, the data is available to the public.

3.4 Continued Monitoring

Ohio and Kentucky commit to continue monitoring concentrations of fine particles at the active sites indicated in Table 3.1 and Appendix A. There are no monitors in the Indiana portion of the Cincinnati-Hamilton, OH-KY-IN nonattainment area, however, IDEM will consult with U.S. EPA Region V staff should changes to the existing Indiana monitoring network become necessary in the future.

4.0 EMISSION INVENTORY

U.S. EPA Redesignation Guidance and Implementation Rules require the submittal of a comprehensive inventory of precursor emissions for fine particles (NO_x, SO_2, and direct $PM_{2.5}$) representative of the year when the area achieved attainment of the annual NAAQS for fine particles (base year). IDEM is using 2008 as the base year. IDEM must also demonstrate that the improvement in air quality between the year that violations occurred and the year that attainment was achieved is based on permanent and enforceable emission reductions. Other requirements related to the emissions inventory include: a projection of the emission inventory to a year at least ten years following redesignation; a demonstration that the projected level of emissions is sufficient to maintain the annual standard for fine particles; and, a commitment to provide future updates of the inventory to enable tracking of emission levels during the ten year

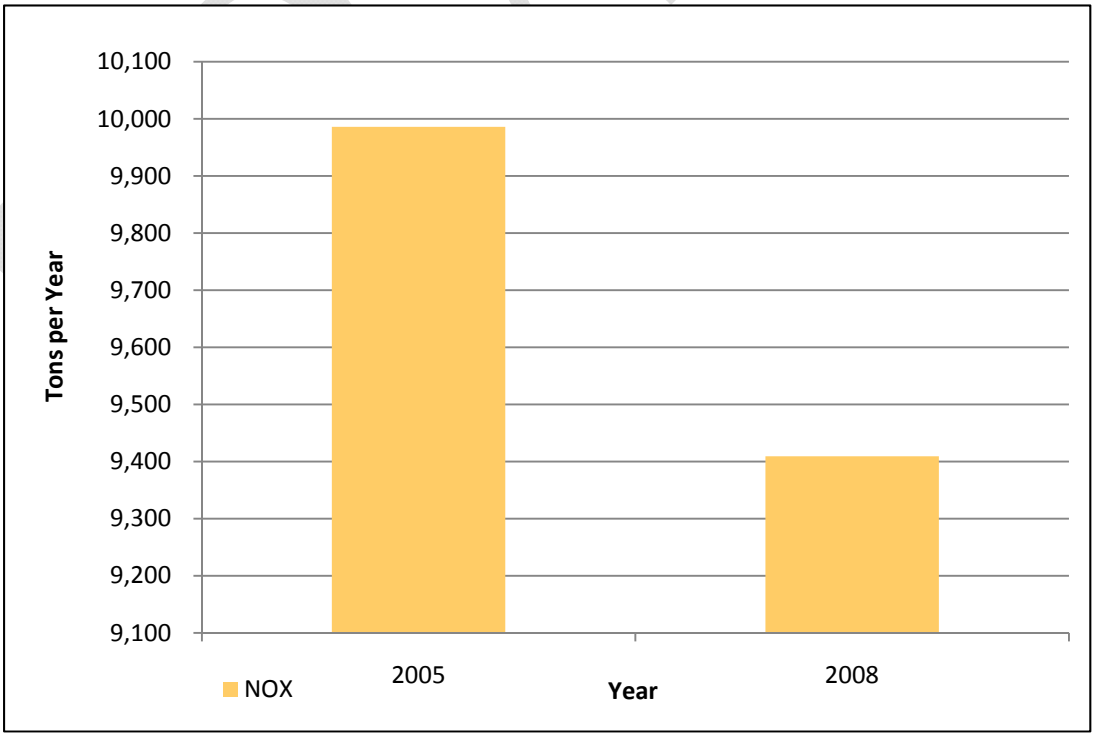
maintenance period. Consistent with the implementation rule for fine particles, IDEM and U.S. EPA do not consider volatile organic compounds (VOCs) or ammonia (NH_3) to be significant contributors to fine particles. The following subsections address each of these requirements.

4.1 Emission Trends

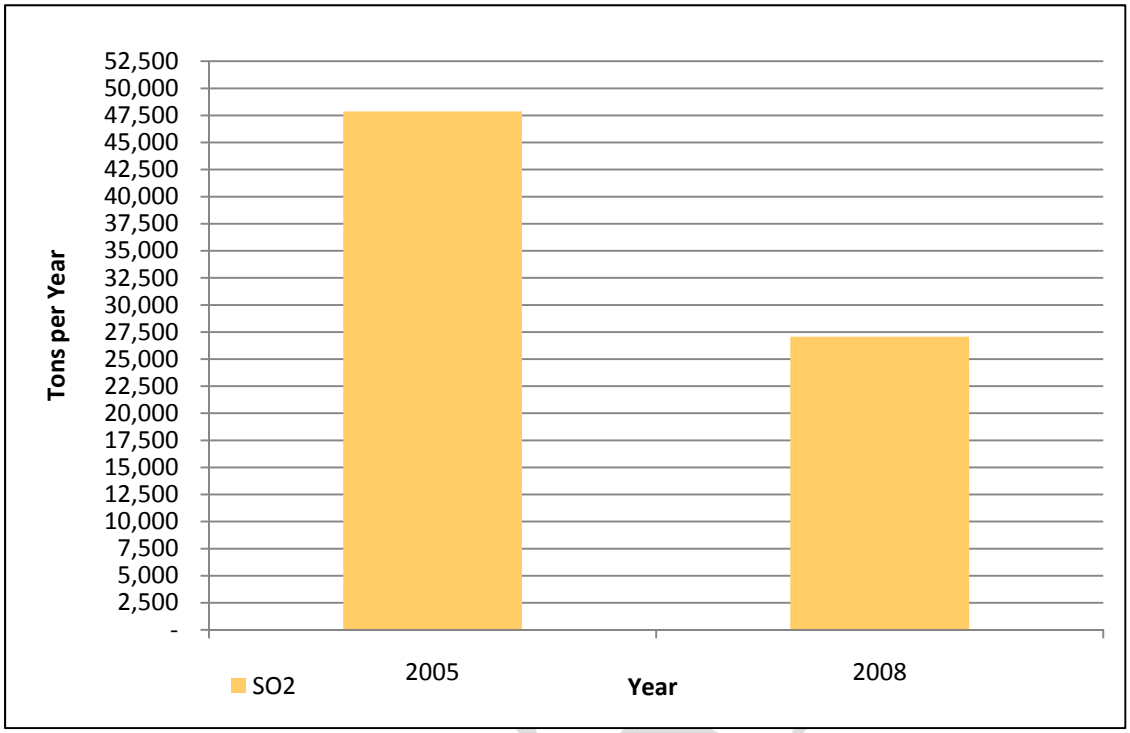
Point Sources

Graphs 4.1, 4.2 and 4.3 show that the trend in point source emissions of NO_x, SO_2, and direct $PM_{2.5}$ respectively for Lawrenceburg Township, Dearborn County, Indiana, generally correspond to the years of monitored values used in this redesignation petition. The point source data are taken from Indiana's emissions reporting program. While an increase in direct $PM_{2.5}$ point source emissions for Lawrenceburg Township in Dearborn County, Indiana is noted, the increase in direct $PM_{2.5}$ emissions from 2005 to 2008 is due to previously unreported emissions from companies that did not submit their direct $PM_{2.5}$ emissions data in 2005, but did submit direct $PM_{2.5}$ data in the 2008 emissions inventory. Graphs 4.4, 4.5 and 4.6 show the trend in point source emissions for the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area. The entire Cincinnati area had a 14.6% reduction in NO_x point source emissions, a 52.1% reduction in SO_2 point source emissions, and a 9.5% reduction in direct $PM_{2.5}$ point source emissions. Point source data for the entire Cincinnati area is the combination of data from Indiana, Kentucky, and Ohio's annual emissions reporting program. Graphs and data tables of emissions for the point source category can be found in Appendix B.

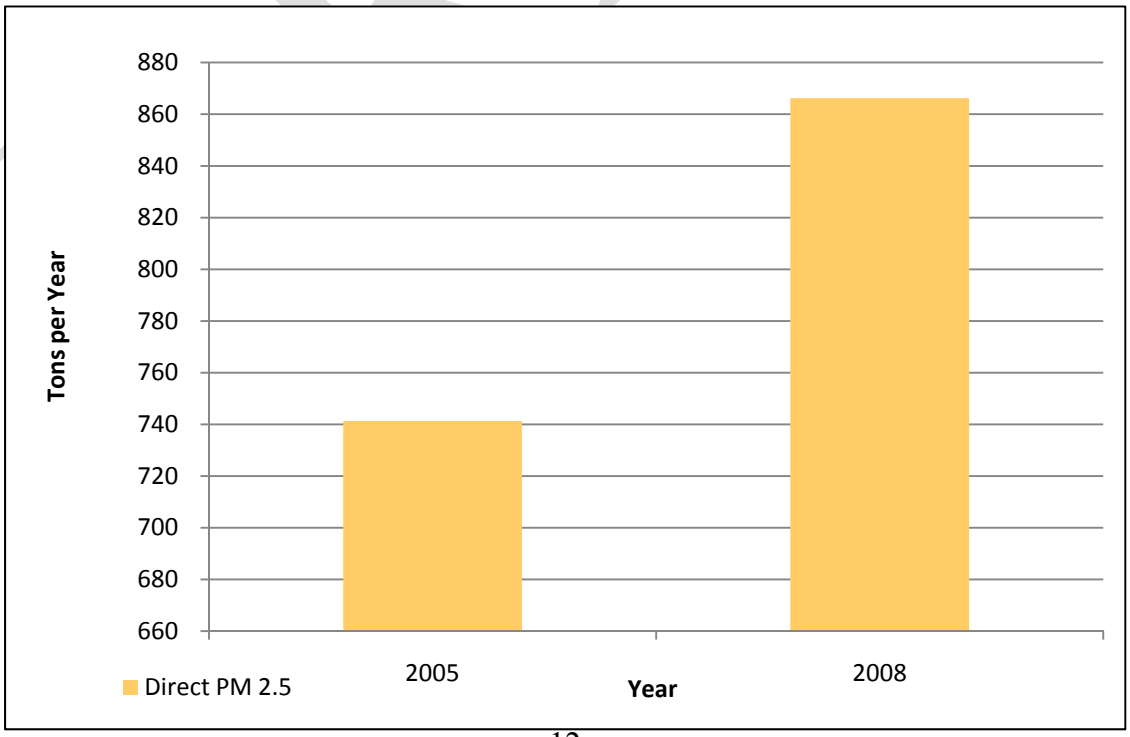
Graph 4.1
Dearborn County, IN NO_x Point Source Emission Trends, 2005 and 2008



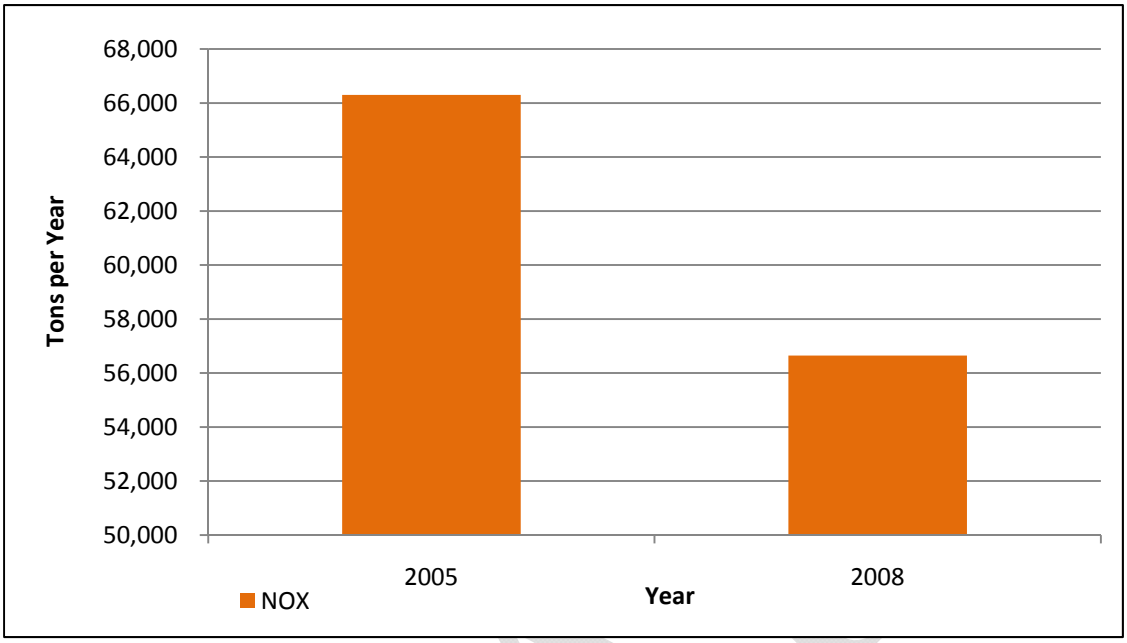
Graph 4.2
Dearborn County, IN SO_2 Point Source Emission Trends, 2005 and 2008



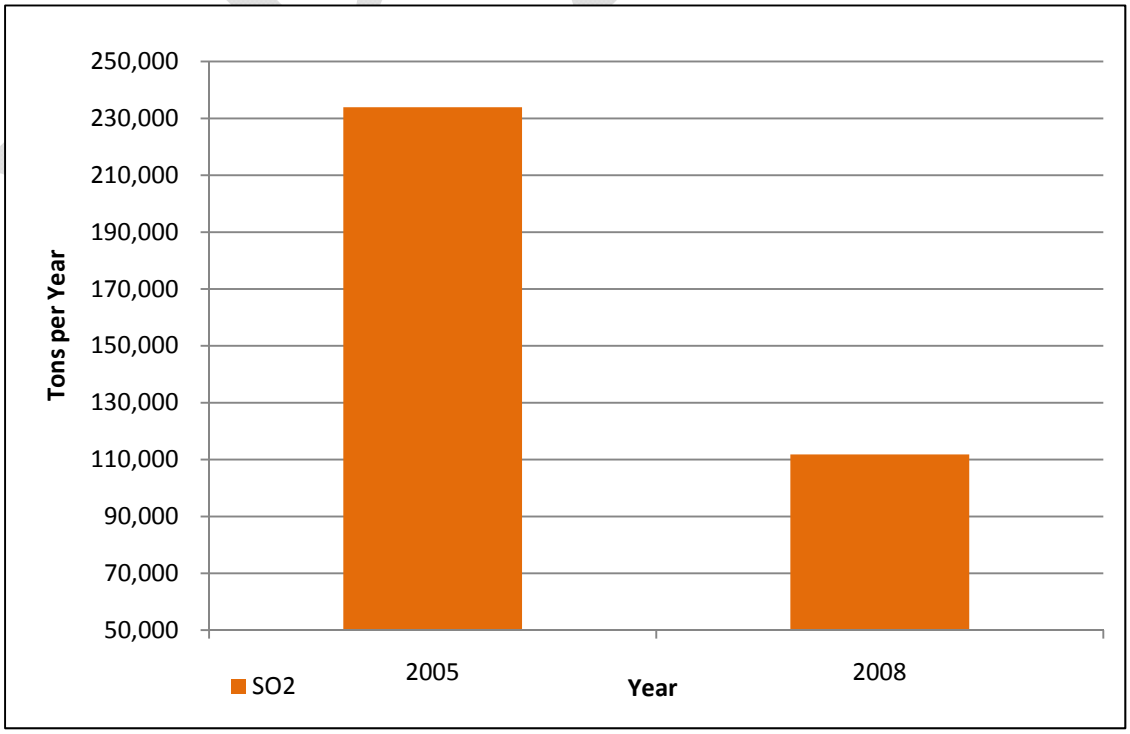
Graph 4.3
Dearborn County, IN Direct $PM_{2.5}$ Point Source Emission Trends, 2005 and 2008



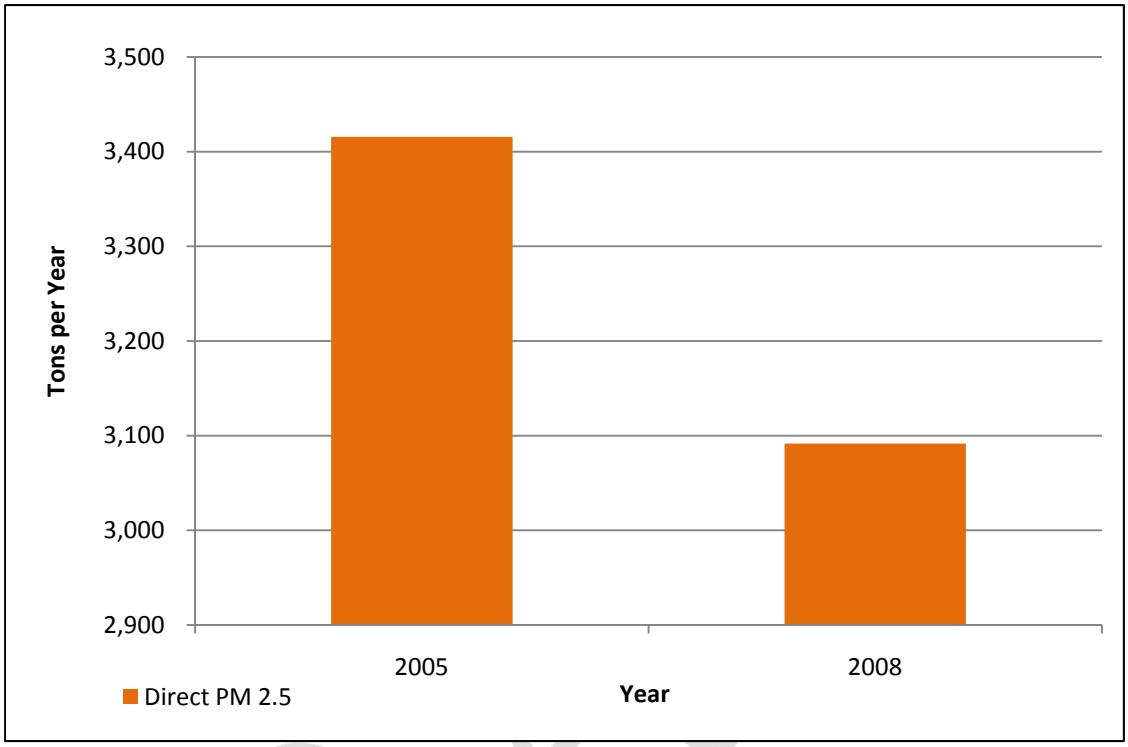
Graph 4.4
Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area NO_x Point Source Emission Trends, 2005 and 2008



Graph 4.5
Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area SO_2 Point Source Emission Trends, 2005 and 2008



Graph 4.6
Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Direct $PM_{2.5}$ Point Source Emission Trends, 2005 and 2008



All Anthropogenic Sources

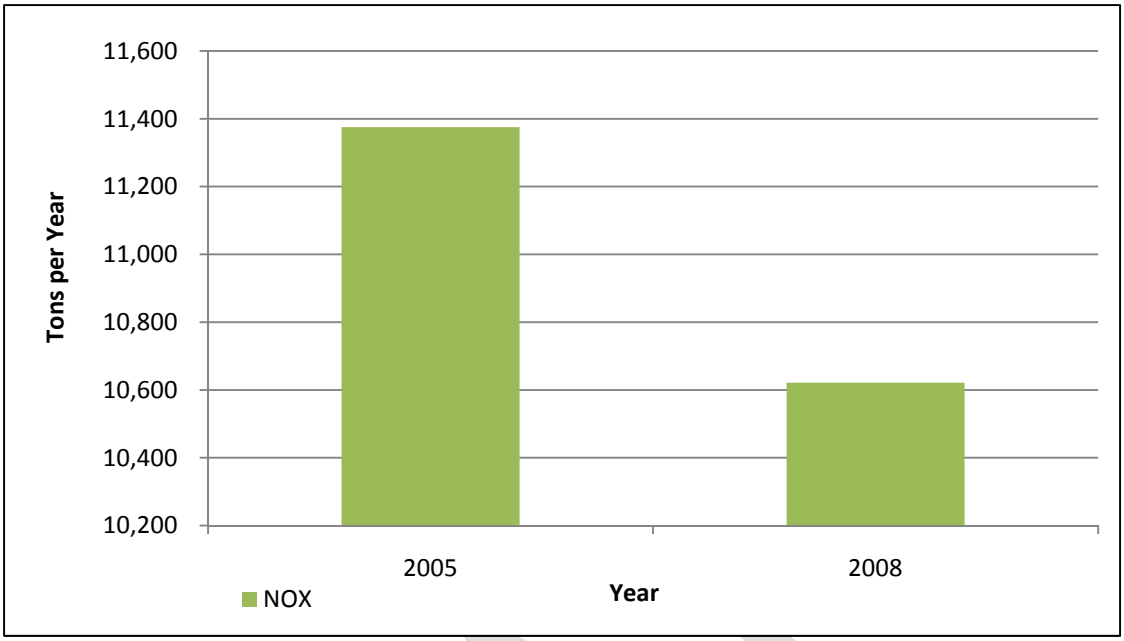
Periodic inventories, which include emissions from all sectors (mobile, area, nonroad, and point source), were prepared for 2005 and 2008. The 2008 data was extrapolated from the 2005 emission inventory. Graphs 4.7, 4.8, and 4.9 show the trends for total NO_x, SO_2, and direct $PM_{2.5}$ emissions for all anthropogenic source categories in Lawrenceburg Township in Dearborn County, Indiana for 2005 and 2008. While an increase in direct $PM_{2.5}$ anthropogenic source emissions for Lawrenceburg Township in Dearborn County, Indiana is noted, the increase in direct $PM_{2.5}$ emissions from 2005 to 2008 is due to previously unreported emissions from companies that did not submit their direct $PM_{2.5}$ emissions data in 2005, but did submit direct $PM_{2.5}$ data in the 2008 emissions inventory. Graphs 4.10, 4.11, and 4.12 show the trends for total NO_x, SO_2, and direct $PM_{2.5}$ emissions for all anthropogenic source categories for the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area for 2005 and 2008. These emissions trends roughly follow the years of monitored trends discussed in Section 3.0. There is a downward trend in NO_x and SO_2 emissions from 2005 to 2008. The decrease in NO_x can be largely attributed to the impact of the NO_x SIP Call. As can be seen by Graph 4.12, overall the direct $PM_{2.5}$ anthropogenic source emissions for the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area have substantially decreased. Graphs and data tables of emissions from each source category are available in Appendix C.

Mobile emissions inventories and projections for all counties were prepared by the Ohio-Kentucky-Indiana Regional Council of Governments (OKI) and is explained in further detail in Section 5.0. All 2005 data for the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area is from the 2005 periodic inventory which has been identified as one of the preferred databases for SIP development. For the 2008 attainment year, emissions were extrapolated from the 2005 Lake Michigan Air Directors Consortium (LADCO) modeling inventory, using LADCO's growth factors, for all sections except point sources (electrical generating units and non-electrical generating units). Point source emissions for 2008 were compiled from Indiana, Kentucky, and Ohio's annual emissions inventory databases.

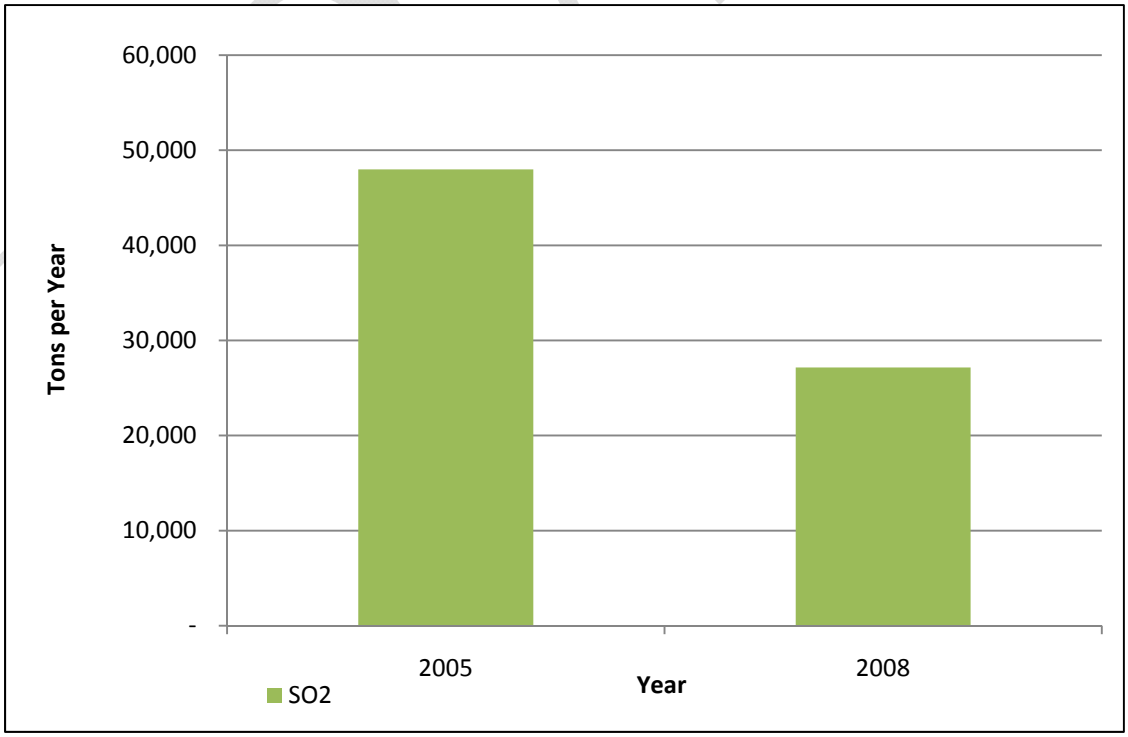
The emissions inventory development and emissions projection discussion below, with the exception of the mobile emissions inventory and projections, identify procedures used by Ohio EPA and LADCO regarding emissions from Ohio's portion of the counties in the Cincinnati-Hamilton, OH-KY-IN nonattainment area that differ from procedures used by Kentucky and Indiana. Indiana and Kentucky emissions data were obtained through the LADCO emission inventory and projections which were prepared using similar methodologies.

For Ohio, the 2005 and 2008 actual $PM_{2.5}$ emissions data below generally contains filterable fraction emissions only and not the condensable fractions, because Ohio EPA did not have a consistent reporting requirement in those years. U.S. EPA Integrated Planning Model(IPM) modeling was used to generate future year EGU emissions with the Clean Air Interstate Rule (CAIR) program. The IPM modeling added additional $PM_{2.5}$ condensible emissions into future years. Therefore, comparing base and attainment year emissions with the future year predictions is not accurate in the IPM CAIR modeling. This step leads to a false perception of significant $PM_{2.5}$ emissions increase. Modeling performed by LADCO, without CAIR, did not incorporate added condensable fraction emissions. Although Ohio EPA has stated that it is most appropriate to evaluate future year emissions that include the CAIR program, because of this flaw, it is more accurate and appropriate for the purposes of $PM_{2.5}$ to evaluate future year emissions without the CAIR program. Therefore all numbers for Ohio for $PM_{2.5}$ in this document are without CAIR, while all numbers for Ohio for NO_x and SO_2 are with CAIR. Both Indiana and Kentucky have used numbers for NO_x, SO_2, and $PM_{2.5}$ with CAIR. Emissions tables and charts in this document are labeled accordingly and can also be found in Appendix C.

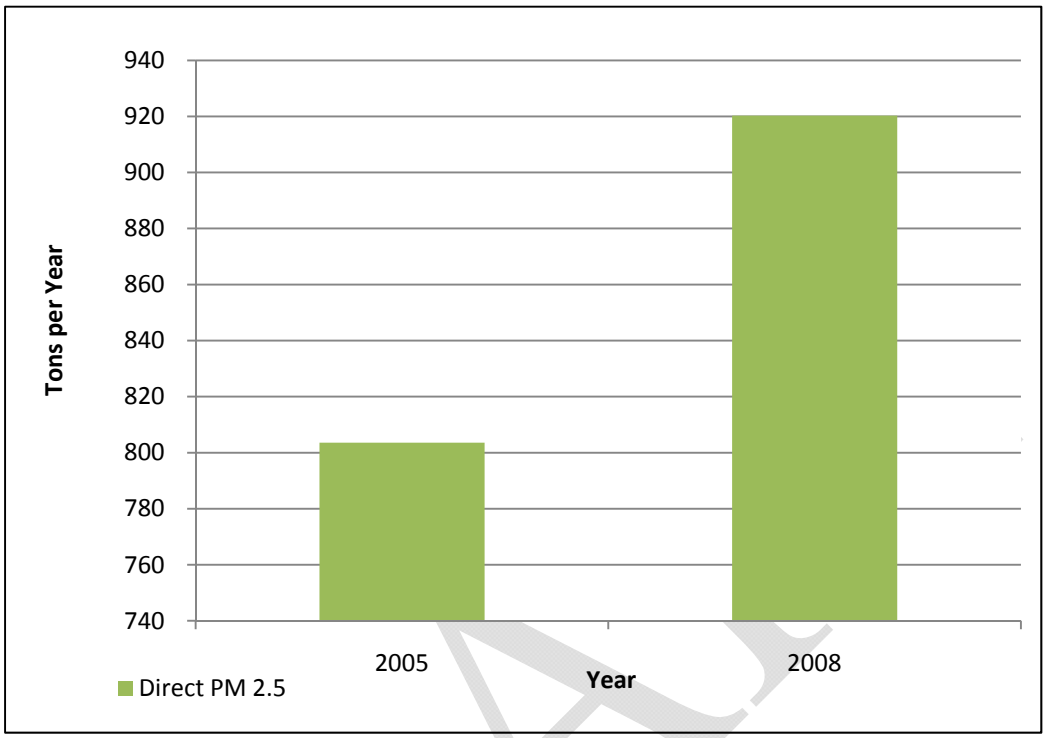
Graph 4.7
NO_x Emission Trends, All Sources in Dearborn County, IN, 2005 and 2008-With CAIR



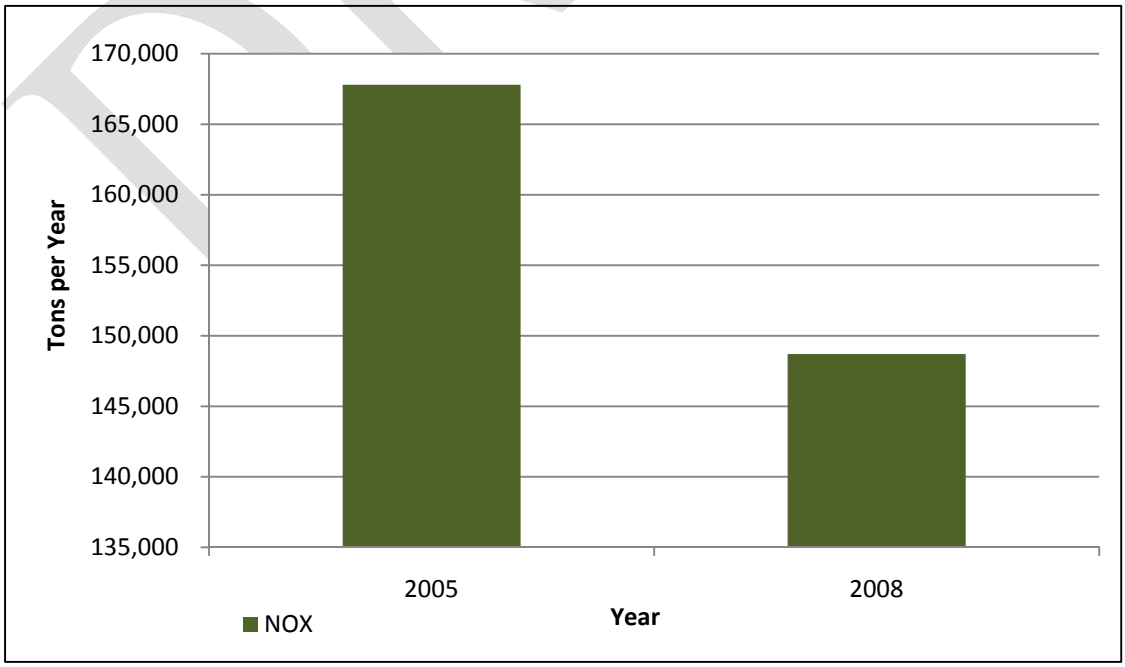
Graph 4.8
SO_2 Emission Trends, All Sources in Dearborn County, IN, 2005 and 2008-With CAIR



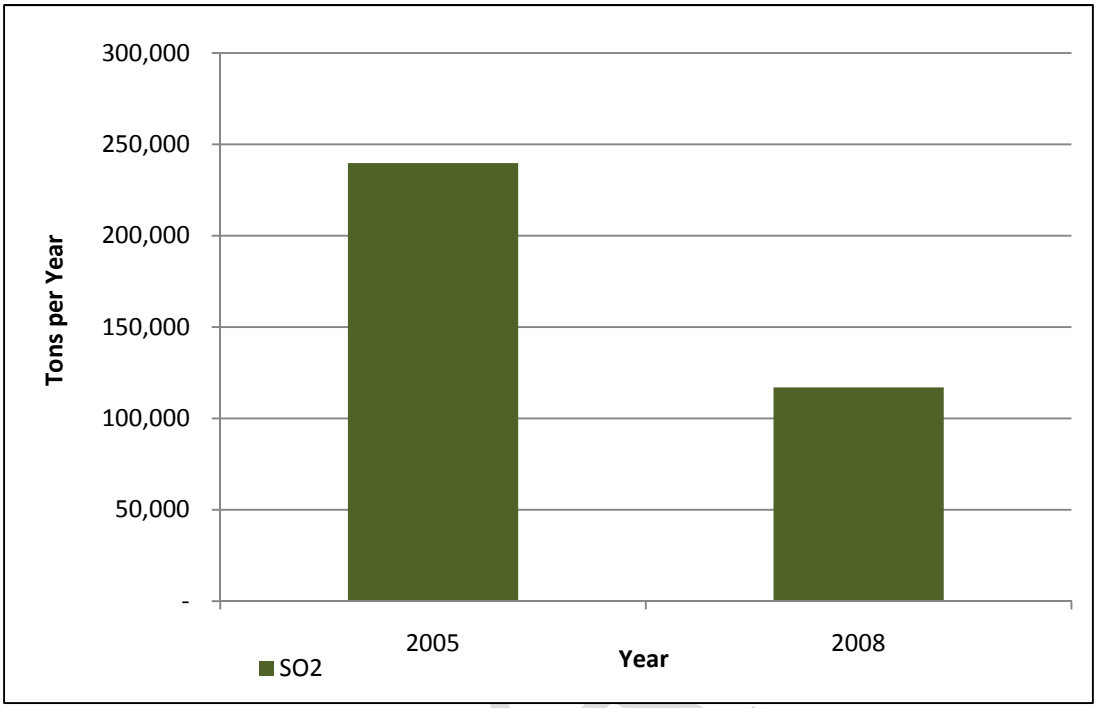
Graph 4.9
Direct $PM_{2.5}$ Emission Trends, All Sources in Dearborn County, IN, 2005 and 2008-With CAIR



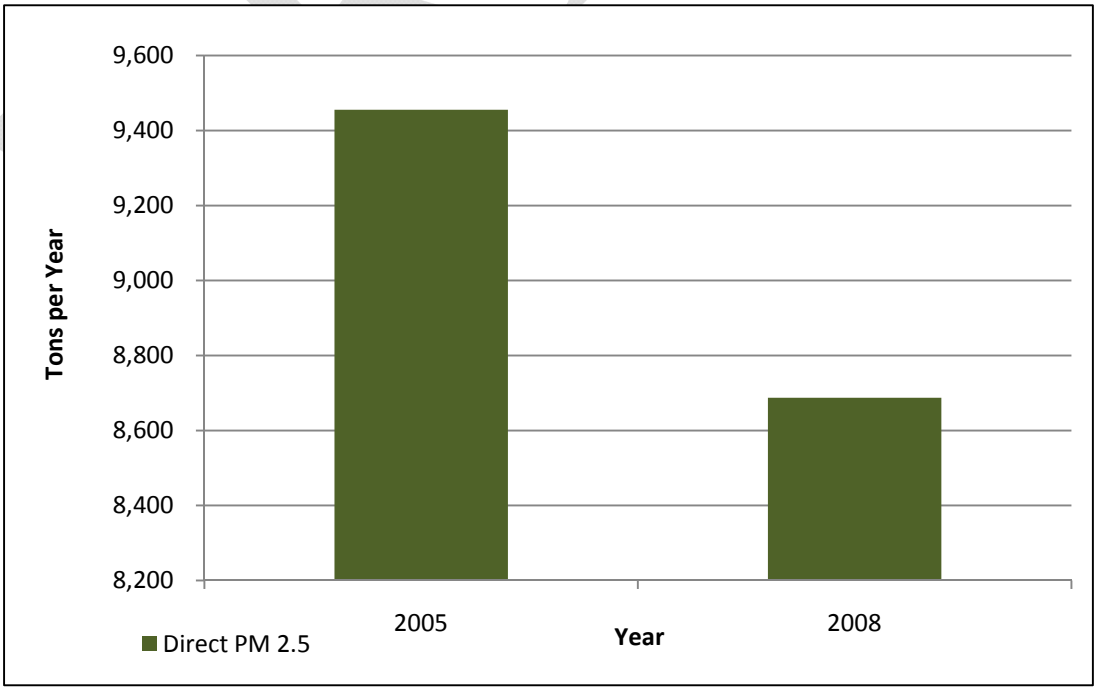
Graph 4.10
NO_x Emission Trends, All Sources in Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area, 2005 and 2008-With CAIR



Graph 4.11
SO_2 Emission Trends, All Sources in Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area, 2005 and 2008-With CAIR



Graph 4.12
Direct $PM_{2.5}$ Emission Trends, All Sources in Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area, 2005 and 2008-Without CAIR



EGU Sources

Both NO_x and SO_2 emissions are decreasing substantially in response to national programs affecting all EGUs such as the Acid Rain program and the NO_x SIP Call. Other sectors of the inventory also impact the formation of fine particles, but large regional sources such as EGUs have a substantial impact on the formation of fine particles.

The data was taken from U.S. EPA's Clean Air Markets database[1]. Data are available sooner for these units than other point sources in the inventory because of the NO_x SIP Call budget and trading requirements. Information from 2003 is significant because some EGUs started operation of their NO_x SIP Call controls in order to generate Early Reduction Credits for their future year NO_x budgets. The first season of the NO_x SIP Call budget period began May 31, 2004.

As part of the NO_x SIP Call, the states were required to adopt into their rules a budget for all large EGUs. Indiana's budget is referenced in 326 IAC 10-4. The budget represents a statewide cap on NO_x emissions. Although each unit is allocated emissions based upon historic heat input, utilities can meet this budget by over-controlling certain units or purchasing credits from the market to account for overages at other units. To summarize, NO_x emissions have dramatically decreased over the years represented on these graphs.

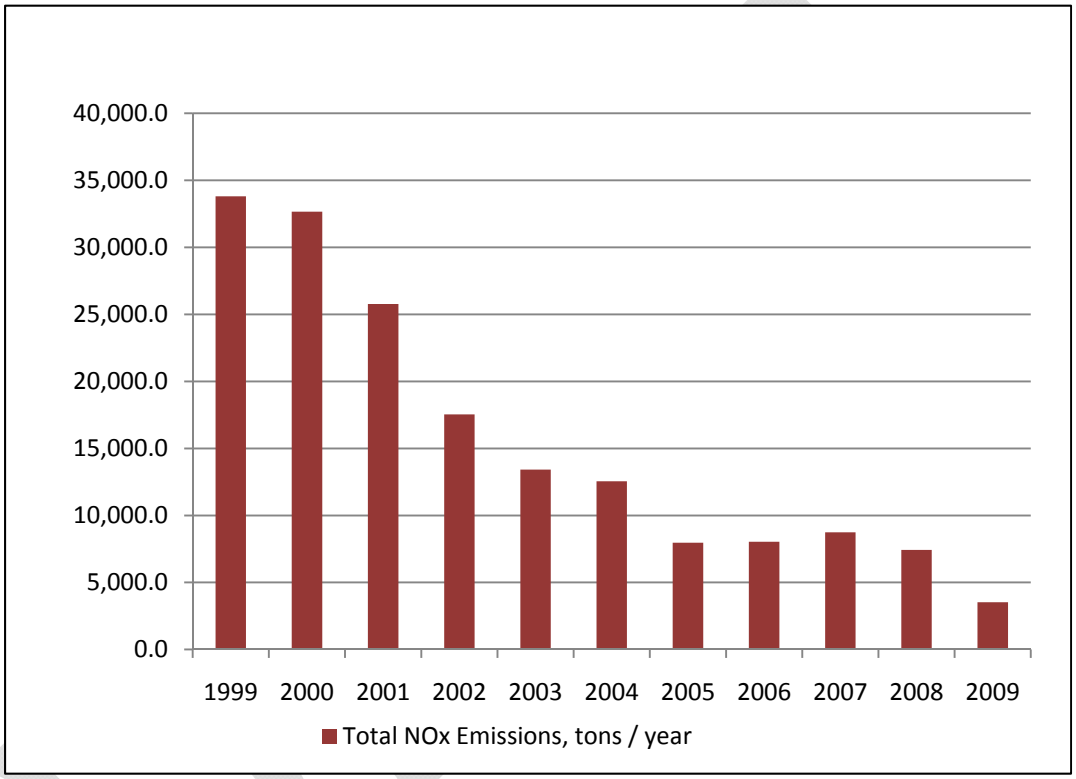
These emissions, capped by the state rule, are expected to remain near these levels throughout the maintenance period covered by this request. The state cap for the NO_x SIP Call remained in place through 2008, at which time the CAIR program superseded it. CAIR, issued in March 2005, adopted by the Indiana Air Pollution Control Board on November 1, 2006, and implemented beginning in 2010, will continue to reduce regional EGU NO_x emissions statewide by approximately another 17% by 2015 and 57% for EGU SO_2 emissions by 2015. The D.C. Circuit court's vacatur of CAIR in July of 2008 and subsequent remand without vacatur in December of 2008 directs U.S. EPA to revise the CAIR rule in the future. The proposed Clean Air Transport Rule (Transport Rule) (CAIR's replacement rule) will result in similar or greater emission reductions than assumed within the current emission inventories once it is implemented.

There is one EGU located in the Indiana portion (Lawrenceburg Township, Dearborn County, Indiana) of the Cincinnati area: American Electric Power (AEP)- Tanner's Creek. Graphs 4.13 and 4.15 depict the trends in NO_x and SO_2 emissions from the EGU in Lawrenceburg Township, Dearborn County, Indiana for the years 1999 to 2009. AEP-Tanner's Creek entered into a Consent Decree with U.S. EPA on October 9, 2007. For NO_x, the Consent Decree calls for low-NOx burners and overfire air. Further, they installed Selective Non-Catalytic Reduction (SNCRs) on Units 1, 2, and 3 in 2008 to meet CAIR requirements. As a general rule, low NO_x burners are around 40% control and SNCRs are an additional 30%. AEP-Tanner's Creek's permit does not require operation of these units, but they need to operate the controls to meet CAIR allowances for now, and the proposed Transport Rule will control when it is effective. For SO_2, the Consent Decree and the permit state AEP-Tanner's Creek has to burn coal not exceeding 1.2% sulfur. With the Consent Decree in place these controls are, therefore,

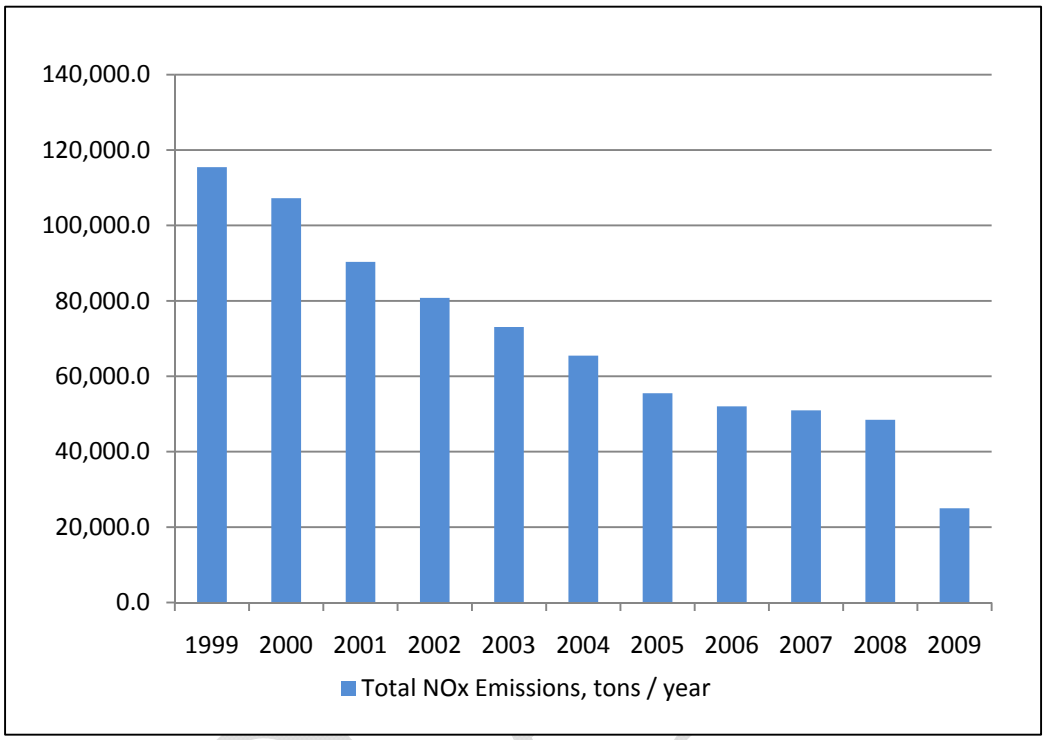
[1] http://www.epa.gov/airmarkets

considered permanent and enforceable and can be associated with the downward trend in NO_x and SO_2 emissions from AEP-Tanner's Creek. Graphs 4.14 and 4.16 depict the trends in NO_x and SO_2 emissions from the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area for the years 1999 to 2009. Graphs and data tables of emissions from the EGU source category can be found in Appendix D.

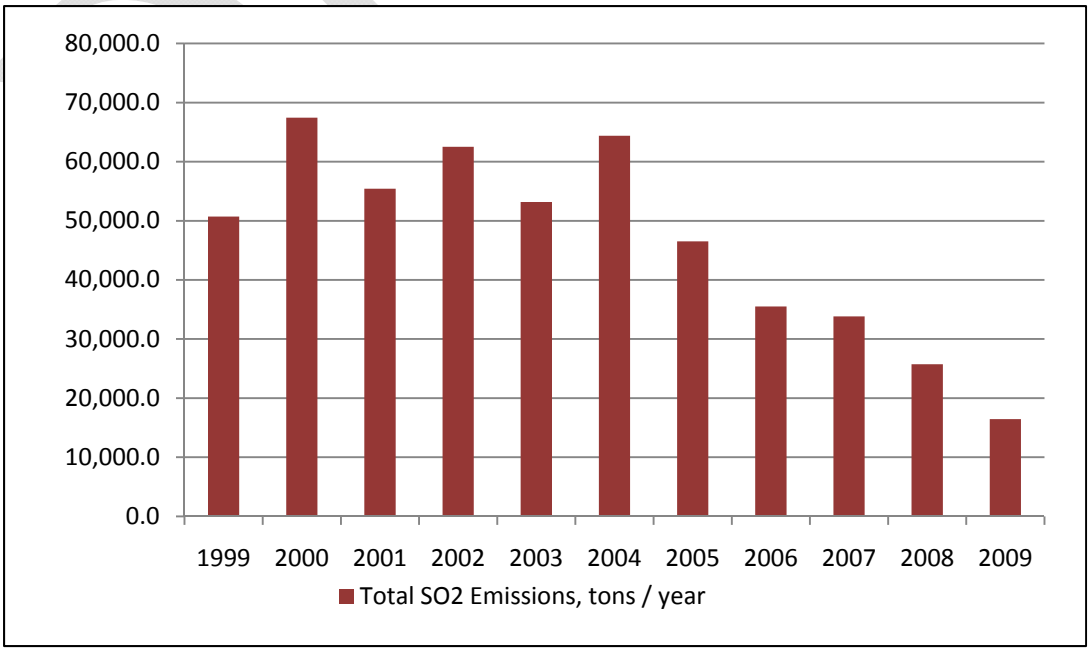
Graph 4.13
Lawrenceburg Township, Dearborn County, Indiana NO_x Emissions from EGUs, 1999 to 2009



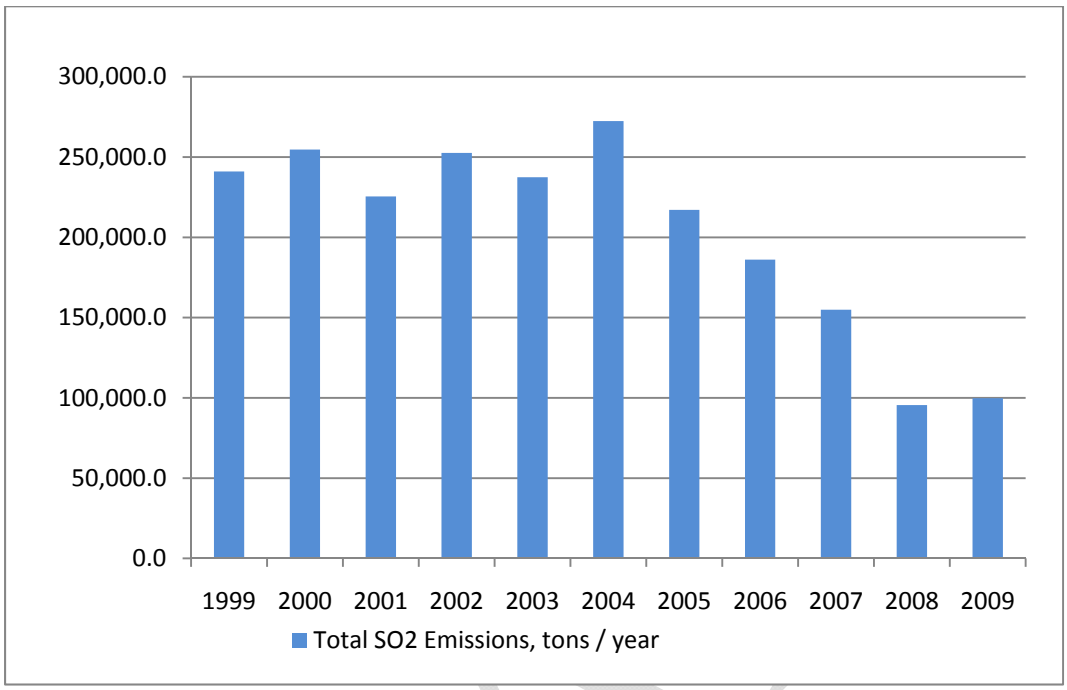
Graph 4.14
Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 1999 to 2009



Graph 4.15
Lawrenceburg Township, Dearborn County, Indiana SO_2 Emissions from EGUs, 1999 to 2009



Graph 4.16
Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 1999 to 2009



4.2 Base Year Inventory

IDEM prepared a comprehensive inventory for the Cincinnati area, including area, mobile, nonroad, and point sources for direct $PM_{2.5}$ and precursors of fine particles (NO_x and SO_2) for 2005 (the year with the most complete emissions inventory available at this time). The 2008 data was extrapolated from the 2005 emission inventory to represent a base year for maintenance purposes. The 2007 implementation rule for the annual fine particles standard states that NO_x, SO_2, and direct $PM_{2.5}$ are the regulated precursors of fine particles. Ammonia and VOCs are not required to be addressed unless the state or U.S. EPA makes a technical demonstration that emissions of these pollutants from sources in the state significantly contribute to $PM_{2.5}$ concentrations in a given nonattainment area. U.S. EPA and Indiana have not determined ammonia or VOCs to be significant contributors to fine particles formation in the State of Indiana. Indiana's 2008 base year inventory was determined by the following:

- Area sources were extrapolated from the Indiana 2005 periodic inventory submitted to U.S. EPA.
- Mobile source emissions were calculated from U.S. EPA's Motor Vehicle Emissions Simulator (MOVES) model-produced emission factors and data extracted from the region's travel-demand model. These emissions were then interpolated as needed to determine 2008 base year values.

- Point source information was compiled from IDEM's emissions statement database and U.S. EPA's Clean Air Markets acid rain database.
- Biogenic emissions are not included in these summaries.
- Nonroad emissions were extrapolated from the 2002 National Emissions Inventory (NEI). To address concerns about the accuracy of some of the categories in U.S. EPA's nonroad emissions model, LADCO contracted with two companies to review the base data and make recommendations. One of the contractors also estimated emissions for two nonroad categories not included in U.S. EPA's nonroad model. Emissions were estimated for commercial marine vessels and railroads. The recreational motorboat population and spatial surrogates (used to assign emissions to each) were significantly updated. The populations for the construction equipment category were reviewed and updated based upon surveys completed in the Midwest and the temporal allocation for agricultural sources was also updated. A new nonroad estimation model was provided by U.S. EPA for the 2002 analysis.
- The emissions data referenced for Kentucky's portion of the nonattainment area were pulled from LADCO's emissions inventory files. This inventory was prepared using similar methodologies. The 2008 data was extrapolated from the 2005 emission inventory to represent a base year for maintenance purposes.

4.3 Emission Projections

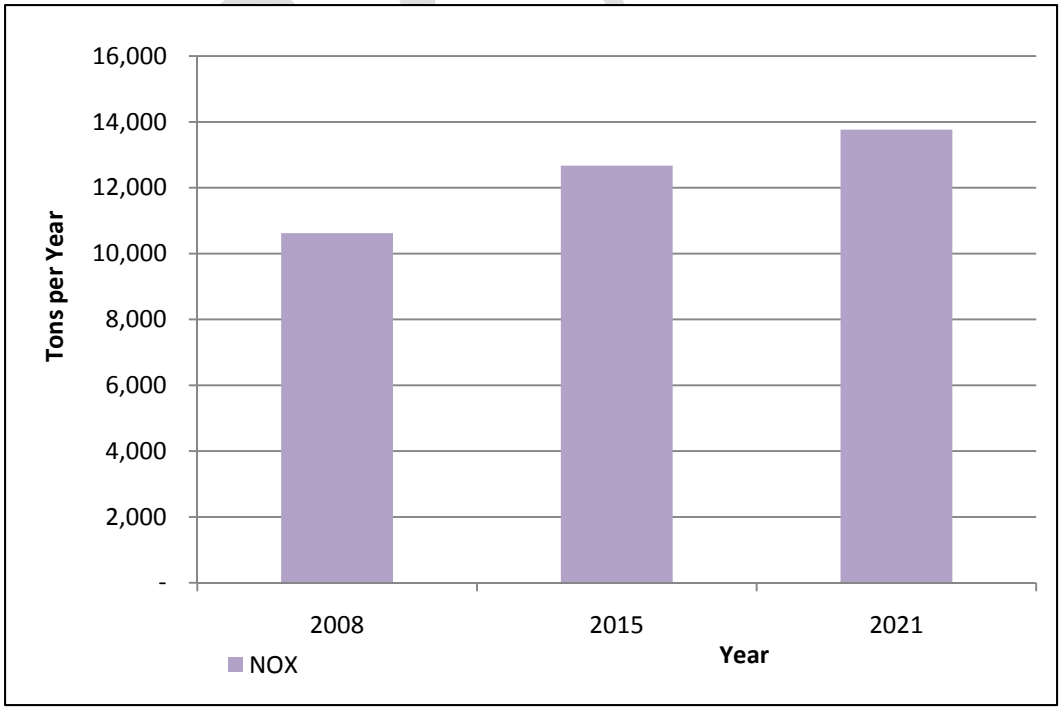
In consultation with the U.S. EPA and other stakeholders, IDEM selected the year 2021 as the maintenance year for this redesignation request. This document contains projected emission inventories for 2015 and 2021. Emission projections were prepared for Dearborn County, Indiana, as well as for the entire nonattainment area. IDEM, with assistance from LADCO, prepared emission projections for 2015 and 2021 for the entire nonattainment area.

The detailed 2015 and 2021 emissions inventory for the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area can be found in Appendix E. Emission trends are an important gauge for continued compliance with the annual standard for fine particles. Therefore, IDEM performed an initial comparison of the inventories for the base year (2008-extrapolated from the 2005 emission inventory), interim year (2015-interpolated from 2009 emissions and 2018 emissions estimates) and maintenance year (2021-extrapolated from 2018 emission estimates) for Dearborn County, Indiana and the entire Cincinnati-Hamilton OH-KY-IN nonattainment area.

For the 2008 attainment year, emissions were extrapolated from the 2005 LADCO modeling inventory, using LADCO's growth factors, for all sections except point sources (electrical generating units and non-electrical generating units). Point source emissions for 2008 were compiled from Indiana, Kentucky, and Ohio's annual emissions inventory databases. The 2015 interim year emissions were estimated based on the 2009 and 2018 LADCO modeling inventory, using LADCO's growth factors, for all sectors. The 2021 maintenance year is based on emissions estimates from the 2018 LADCO modeling.

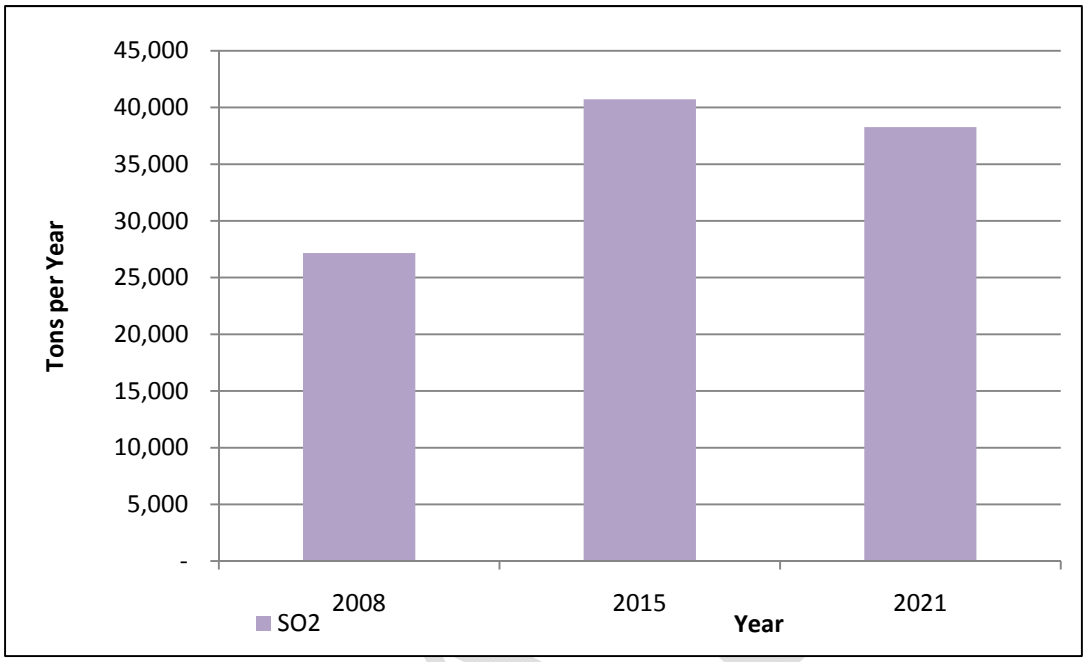
Graphs 4.17, 4.18, 4.19, and 4.20 visually compare 2008 (base year) NO_x, SO_2, and direct $PM_{2.5}$ estimated emissions with the 2015 and 2021 projected emissions for Lawrenceburg Township, Dearborn County, Indiana. Graphs 4.21, 4.22, 4.23, and 4.24 visually compare the 2008 (base year) NO_x, SO_2 and direct $PM_{2.5}$ estimated emissions with the 2015 and 2021 projected emissions for the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area. AEP-Tanner's Creek accounts for over 80% of Lawrenceburg Township's total emissions. However, Lawrenceburg Township accounts for a minor portion (14%) of the total nonattainment area emissions. While an increase can be seen in the projected emissions for Lawrenceburg Township, Dearborn County, Indiana for NO_x, SO_2 and direct $PM_{2.5}$, overall emissions in the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area are decreasing substantially as can be seen in Graphs 4.21, 4.22, 4.23 and 4.24. Mobile source emission inventories are further described in Section 5.0. In addition to LADCO's estimates, point source emissions were projected based upon the statewide EGU NO_x budgets from the Indiana NO_x rule. It should be noted that EGU emission estimates for 2015 and 2021 were projected utilizing the Department of Energy Information's Annual Energy Outlook Supplemental tables for the year 2018. These tables were generated for the reference case of the Annual Energy Outlook 2007 (AEO 2007) using the National Energy Modeling System. Future year actual emissions for Lawrenceburg Township may vary based upon the consent decree for AEP which includes Tanner's Creek. Additionally, the SO_2 and NO_x allocations for AEP-Tanner's Creek for 2014 and beyond within the proposed Transport Rule are less than 2008 actual emissions. Graphs and data tables of emissions from the EGU source category can be found in Appendix D.

Graph 4.17
Comparison of 2008, 2015 and 2021 Projected NO_x Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR



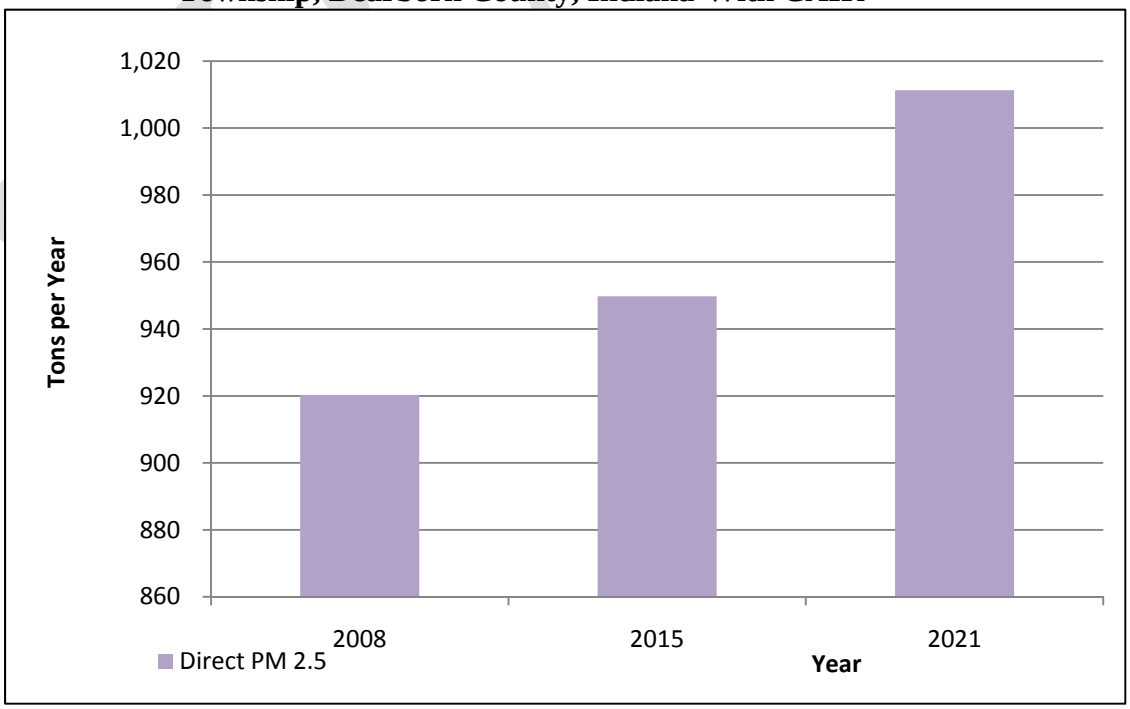
Refer to Section 4.3 above for explanation of projected increase in emissions.

Graph 4.18
Comparison of 2008, 2015 and 2021 Projected SO_2 Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR



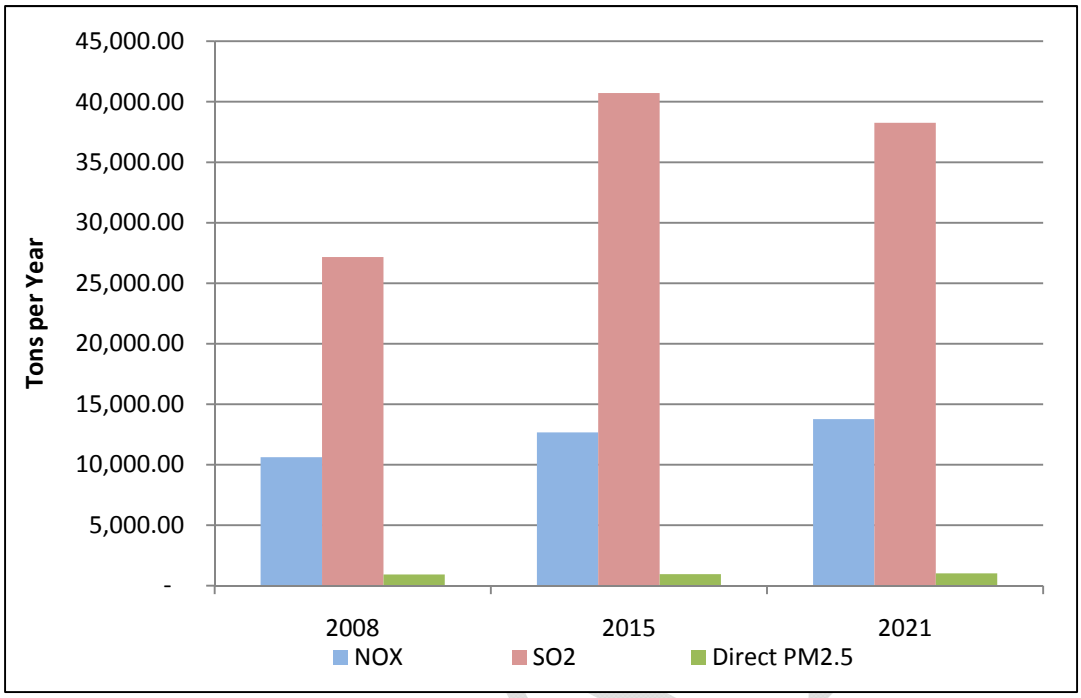
Refer to Section 4.3 above for explanation of projected increase in emissions.

Graph 4.19
Comparison of 2008, 2015 and 2021 Projected Direct $PM_{2.5}$ Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR

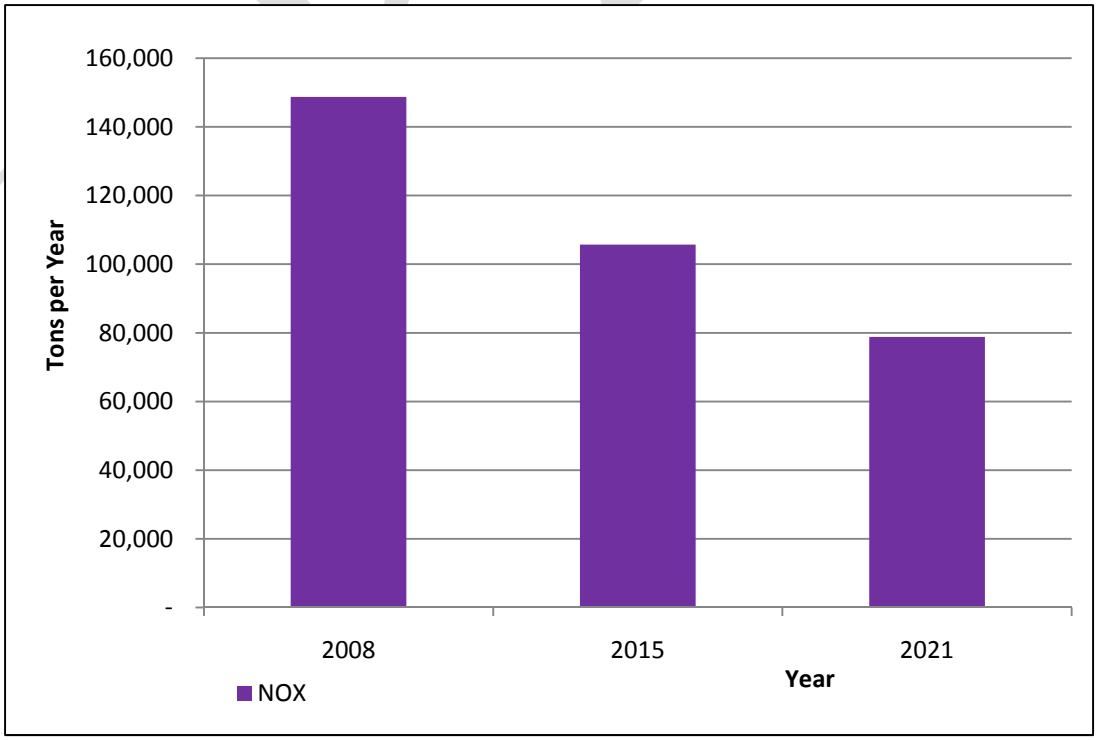


Refer to Section 4.3 above for explanation of projected increase in emissions.

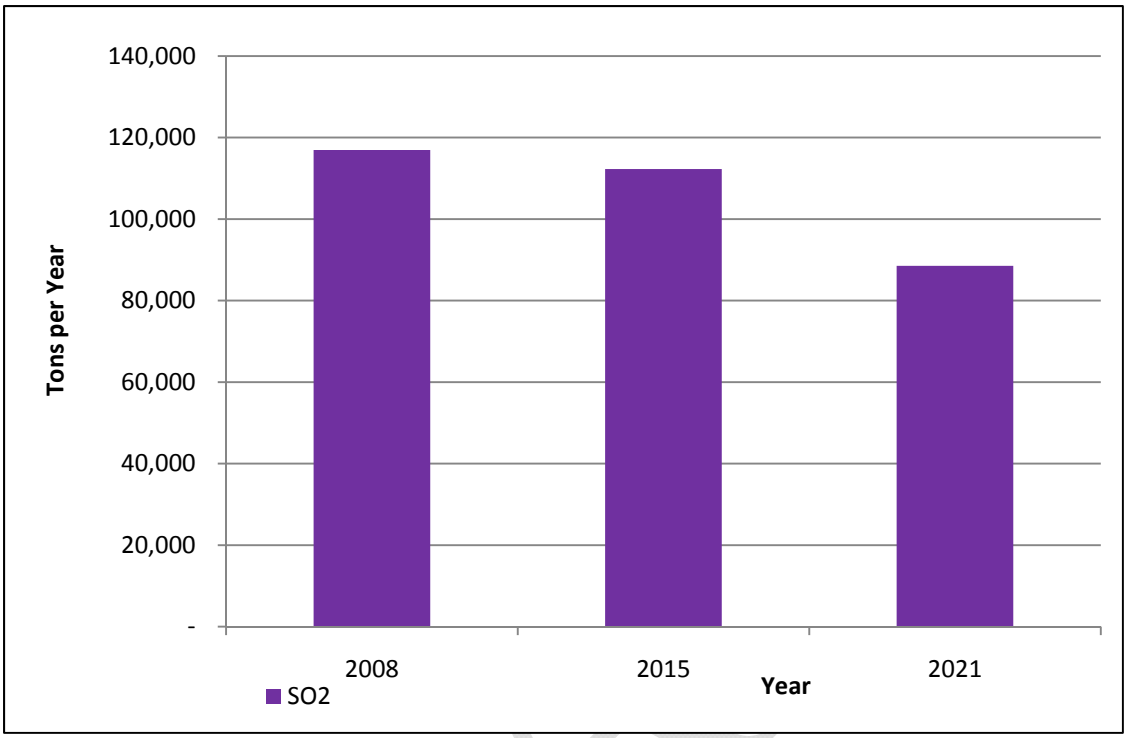
Graph 4.20
Comparison of 2008, 2015 and 2021 Projected SO_2, NO_x and Direct $PM_{2.5}$ Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR



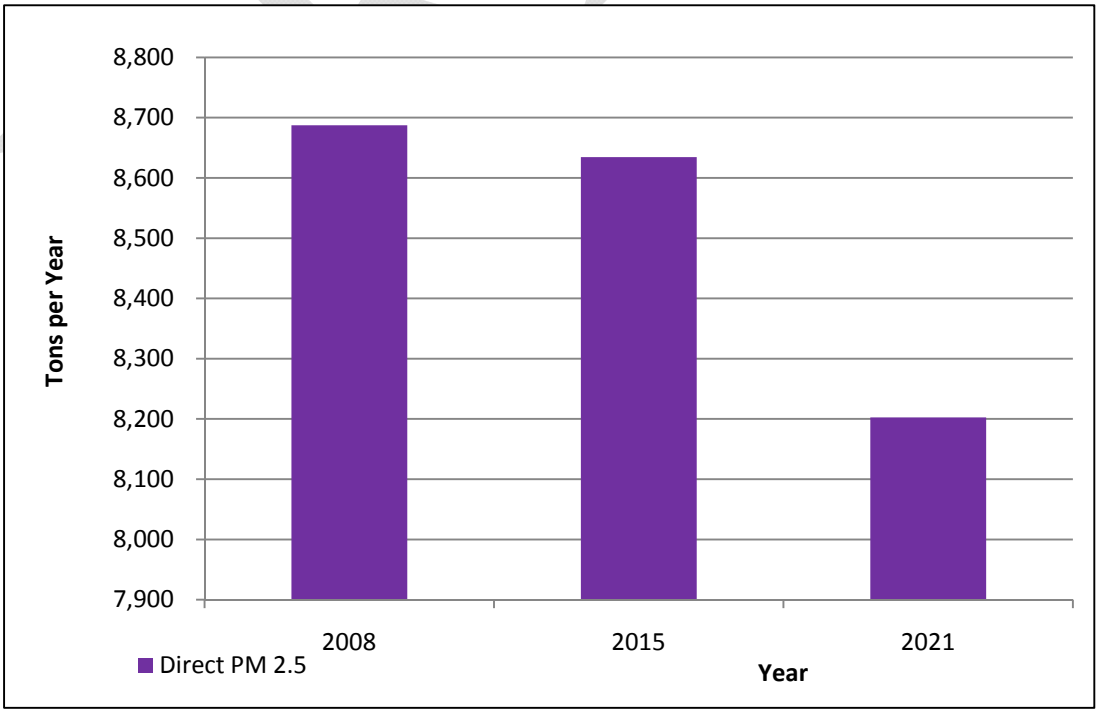
Graph 4.21
Comparison of 2008, 2015 and 2021 Projected NO_x Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-With CAIR



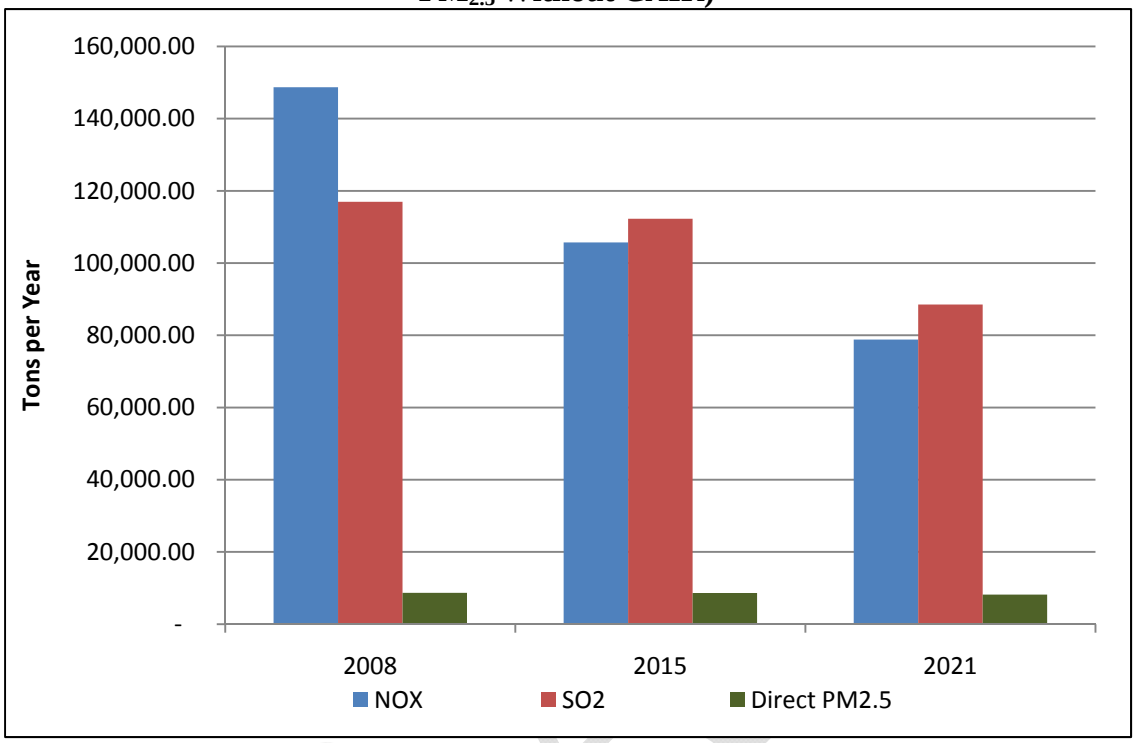
Graph 4.22
Comparison of 2008, 2015 and 2021 Projected SO_2 Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-With CAIR



Graph 4.23
Comparison of 2008, 2015 and 2021 Projected Direct $PM_{2.5}$ Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-Without CAIR



Graph 4.24
Comparison of 2008, 2015 and 2021 Projected SO_2, NO_x and Direct $PM_{2.5}$ Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-(NO_x and SO_2 With CAIR, $PM_{2.5}$ Without CAIR)



NO_x emissions within the entire Cincinnati-Hamilton, OH-KY-IN nonattainment area are projected to decline by 46.9% between 2008 and 2021. Emission reduction benefits from U.S. EPA rules covering the NO_x SIP Call, Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, Highway Heavy-Duty Engine Rule, and Nonroad Diesel Engine Rule are factored into the changes. Additionally, due to implementation of the NO_x SIP Call across the eastern United States, NO_x and fine particle levels entering the Cincinnati area will also be decreased. SO_2 emissions within the Cincinnati area are projected to decline by 24.3% between 2008 and 2021. Direct $PM_{2.5}$ emissions from 2008 to 2021 are also projected to decline by 5.6% within the Cincinnati area, see Tables 4.1 and 4.2.

Table 4.1
Comparison of 2008 Estimated and 2021 Projected Emission Estimates Lawrenceburg Township, Dearborn County, Indiana (Tons Per Year)

	2008	2021	Change	% Change
NO_x	10,621.35	13,767.56	3,146.21	29.6%
SO_2	27,164.52	38,261.63	11,097.11	40.9%
Direct $PM_{2.5}$	920.29	1,011.29	91.00	9.9%

Table 4.2
Comparison of 2008 Estimated and 2021 Projected Emission Estimates Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

	2008	2021	Change	% Change
NO_x	148,706.15	78,819.18	-69,886.97	-46.9%
SO_2	116,966.42	88,540.12	-28,426.30	-24.3%
Direct $PM_{2.5}$	8,687.22	8,202.63	-484.59	-5.6%

4.4 Demonstration of Maintenance

Quality assured ambient air quality data from all the monitoring sites indicate that air quality in the Cincinnati area met the annual NAAQS for fine particles for the three-year period ending in 2009. Furthermore, quality assured ambient air quality monitoring data from all monitoring sites within the Cincinnati area indicate that air quality met the NAAQS for fine particles for the three-year period ending in 2009. U.S. EPA's Redesignation Guidance (Page 9) states, "A state may generally demonstrate maintenance of the NAAQS by either showing that future emissions of a pollutant or its precursors will not exceed the level of the attainment inventory, or by modeling to show that the future mix of sources and emissions rates will not cause a violation of the NAAQS." Emissions projections outlined in Section 4.0 of this document clearly illustrate that regional NO_x and SO_2 emissions in the area will continue to decline leading to local reductions between 2008 and 2021 (maintenance plan horizon). Section 7.0 further discusses the implications of these emission trends and provides an analysis to support these conclusions.

In Indiana, major point sources in all counties are required to submit air emissions information once every three years, or annually, if the NO_x or SO_2 potential to emit is greater than 2,500 tons per year in accordance with the Emission Reporting Rule, 326 IAC 2-6. IDEM prepares a new periodic inventory for all precursor emission sectors every three years. These precursor emission inventories will be prepared for 2011, 2014, and 2017, as necessary, to comply with the inventory reporting requirements established in the CAA. Emissions information will be compared to the 2008 base year and the 2021 projected maintenance year inventories to assess emission trends, as necessary, to assure continued compliance with the annual standard for fine particles.

4.5 Permanent and Enforceable Emission Reductions

Permanent and enforceable reductions of NO_x and SO_2 have contributed to the attainment of the annual standard for fine particles. Some of these reductions were due to the implementation of the NO_x SIP Call and some were due to the application of tighter federal standards on motor vehicles and fuels.

Section 6.0 identifies the emission control measures specific to Dearborn County, Indiana, as well as the implementation status of each measure.

4.6 Provisions for Future Updates

As required by Section 175A(b) of the CAA, Indiana commits to submit to the Administrator, eight years after redesignation, an additional revision of this SIP. The revision will contain Indiana's plan for maintaining the national primary fine particles air quality standard for ten years beyond the first ten-year period after redesignation.

5.0 MOBILE SOURCE EMISSION BUDGETS

U.S. EPA requirements outlined in 40 CFR 93.118(e)(4) stipulate that mobile source emissions budgets for $PM_{2.5}$ and NO_x be established as part of a SIP. The mobile source emissions budgets are necessary to demonstrate conformance of transportation plans and improvement programs with the SIP.

The following is a summary of the detailed mobile input and output calculation files located in Appendix F.

5.1 Onroad Emissions Estimates

The Ohio-Kentucky-Indiana Regional Council of Governments (OKI) is the Metropolitan Planning Organization (MPO) for the Cincinnati-Hamilton OH-KY-IN area which includes: Dearborn County in Indiana; Butler, Clermont, Hamilton, and Warren counties in Ohio; and, Boone, Campbell, and Kenton counties in Kentucky. This organization maintains a travel demand forecasting model that is used to simulate the traffic in the area and to predict what traffic would be in future years given growth expectations. The model is used mostly to identify where travel capacity will be needed and to determine the infrastructure requirements necessary to meet that need. It is also used to support the calculation of mobile source emissions. The travel demand forecasting model is used to predict the total daily vehicle miles traveled (VMT) and the U.S. EPA software program referred to as MOVES is used to produce emission factors to calculate the emissions per mile. The product of these two outputs, once combined, is the total amount of pollution emitted by onroad vehicles for the particular analyzed area.

5.2 Overview

Broadly described, MOVES is used to generate "emission factors," which are the average emissions per mile (grams/mile) for direct $PM_{2.5}$ and $PM_{2.5}$ precursors, including NO_x and SO_2. There are numerous variables that can affect the emission factors. The vehicle-fleet (vehicles on the road) age and the vehicle types have a major affect on the emission factors. The facility-type the vehicles are traveling on (MOVES facility-types are Freeway, Arterial, Local, and Ramp) and the vehicle speeds also affect the emission factor values. Meteorological factors such as air temperature and humidity affect the emission factors, as does fuel type, such as low Reid Vapor Pressure (RVP) gasoline. These data are estimated using the *best available data* to generate emission factors for direct $PM_{2.5}$ and $PM_{2.5}$ precursors, including NO_x and SO_2. After emission factors are generated, the emission factors must be multiplied by the VMT to determine the quantity of vehicle-related emissions. This information derives from the travel demand model

(TDM).

It should be noted that each year analyzed will have different emission factors, volumes, speeds, and likely some additional links. MOVES input and output files can all be found in Appendix F.

5.3 Emission Estimates

Table 5.1 outlines the onroad emission estimates for the Ohio and Indiana portions of the nonattainment area for the years 2005, 2008 (Attainment Year), 2015 (Interim Year), and 2021 (Horizon Year). The following emission estimates are based on the actual TDM network runs for the years 2005, 2008, 2015, and 2021.

Table 5.1
Emission Estimates for Onroad Mobile Sources
for the Cincinnati-Hamilton OH-KY-IN $PM_{2.5}$ Nonattainment Area

Cincinnati-Hamilton OH-KY-IN NA Area	**2005**	**2008**	**2015**	**2021**
$PM_{2.5}$ (tons/year)	2,272.50	2,034.23	1,598.67	1,128.35
NO_x (tons/year)	58,423.36	51,357.02	31,064.20	18,911.05
Lawrenceburg Township (Dearborn County Indiana) subtotal				
$PM_{2.5}$ (tons/year)	33.98	29.89	25.14	18.11
NO_x (tons/year)	865.46	748.81	482.33	297.95
Lawrenceburg Township subtotal %				
$PM_{2.5}$ (tons/year)	1.50	1.47	1.57	1.61
NO_x (tons/year)	1.48	1.46	1.55	1.58

Table 5.2 contains the 2015 and 2021 regional mobile source emissions budgets for the Ohio and Indiana portions of the nonattainment area.

Table 5.2
Mobile Source Emission Budgets for the Ohio and Indiana Portions
of the Cincinnati $PM_{2.5}$ Nonattainment Area

	2015	**2021**
$PM_{2.5}$ (tons/year)	1,678.60	1,241.19
NO_x (tons/year)	35,723.83	21,747.71

Consistent with the federal implementation rule for fine particles, IDEM does not consider mobile SO_2 to be a significant contributor to fine particles for this nonattainment area, as SO_2 constitutes less than one percent (<1%) of the area's total anthropogenic emissions for the years 2005, 2008, 2015, or 2021.

This document creates an interim year budget for 2015 and a horizon year budget for 2021 for the Ohio and Indiana portions of the nonattainment area. These budgets are based on the 2008 onroad emission inventory used to support photochemical modeling for the same year, and has incorporated an appropriate safety margin as described below. A similar document was created for the Kentucky portion of the nonattainment area.

Initial Base M (2005) Comprehensive Air Quality Model with Extension (CAMx) modeling results indicated a worst case future design value in the Cincinnati-Hamilton OH-KY-IN nonattainment area of 84 ppb. In an effort to accommodate future variations in TDMs and vehicle miles traveled forecast when no change to the network is planned, IDEM consulted with the interagency consultation group, including U.S. EPA – Region 5, to determine a reasonable approach to address this variation. The interagency consultation group approved a five percent (5%) safety margin for $PM_{2.5}$ mobile source emissions estimates for the year 2015, a ten percent (10%) safety margin for $PM_{2.5}$ mobile source emissions estimates for the year 2021, and a fifteen percent (15%) safety margin for NO_x mobile source emissions estimates for the years 2015 and 2021.

Safety margins are appropriate because: 1) there is an acknowledged potential variation in VMT forecast and potential estimated mobile source emissions due to expected modifications to TDM and mobile emissions models; and 2) the total decrease in emissions from all sources is sufficient to accommodate the safety margin allocations detailed above to mobile sources while still continuing to maintain total emissions in the Cincinnati-Hamilton OH-KY-IN area well below the 2008 attainment level of emissions. These safety margins were calculated by adding a straight-line percentage to the mobile source emission estimates for the years 2015 and 2021. Safety margin, as defined by the conformity rule, looks at the total emissions from all sources in the nonattainment area. The resulting 2015 and 2021 budgets for $PM_{2.5}$ and NO_x emissions remain well below the 2005 base year emissions referenced in Table 5.1.

In summary, for all three states combined, the mobile budget safety margin allocation translates into:

- An allocation of 98.49 tons/year for $PM_{2.5}$ and 5,709.06 tons/year for NO_x for 2015.
- An allocation of 140.38 tons/year for $PM_{2.5}$ and 3,799.82 tons/year for NO_x for 2021.

The federal rule at 40 CFR 93.101 defines safety margin as the amount by which the total projected emissions from all sources of a given pollutant are less than the total emissions that would satisfy the applicable requirement for reasonable further progress, attainment, or maintenance. When compared to the overall safety margin as defined by 40 CFR 93.101, it is evident this allocation to mobile sources is significantly below the total safety margin for all sources in the Cincinnati-Hamilton OH-KY-IN area as detailed in Table 4.2.

While IDEM believes that this is sufficient to support the requested increase, IDEM and its partners will be conducting additional air quality modeling which will include the adjusted on-road mobile emissions as well as any additional corrections and modifications that may be necessary due to the constant review and evaluation of the model inputs.

All methodologies, latest planning assumptions, and margins of safety were determined appropriate through the interagency consultation process.

6.0 CONTROL MEASURES AND REGULATIONS

This section provides specific information on the control measures that have been or will be implemented in Dearborn County, Indiana, including CAA requirements and additional state or local measures implemented beyond CAA requirements.

6.1 Reasonably Available Control Technology (RACT)

As required by Section 172 of the CAA, Indiana in the mid-1990s promulgated rules requiring RACT for emissions of VOCs. There were no specific rules required by the CAA, such as RACT for existing sources, beyond statewide rules. Statewide RACT rules have applied to all new sources locating in Indiana since that time. The Indiana rules are found in 326 IAC 8. The following is a listing of applicable rules:

326 IAC 8-1-6	BACT for Non-Specific Sources
326 IAC 8-2	Surface Coating Emission Limitations
326 IAC 8-3	Solvent Degreasing Operations
326 IAC 8-4	Petroleum Sources
326 IAC 8-5	Miscellaneous Operation
326 IAC 8-6	Organic Solvent Emission Limitations

Since Dearborn County, Indiana, attained the annual NAAQS for fine particles prior to an Attainment SIP or RACT SIP being due, and since the Implementation Rule for fine particles stipulates that states are only required to draft and implement RACT rules for the precursor emission reductions necessary to attain the standard, no further RACT rules are required for this area. These Indiana rules are CAA requirements already in the SIP and provide secondary benefits for $PM_{2.5}$.

6.2 Implementation of Past SIP Revisions

The Cincinnati area was only recently designated nonattainment for the annual standard for fine particles and the area has attained the standard well in advance of its attainment deadline of 2010. As a result, Indiana is no longer required to develop and submit an Attainment SIP or RACT SIP for this area under the annual NAAQS for fine particles.

6.3 Nitrogen Oxides (NO_x) Rule

The U.S. EPA NO_x SIP Call required twenty-two states to adopt rules that would result in significant emission reductions from large EGUs, industrial boilers, and cement kilns in the eastern United States. Indiana adopted this rule in 2001. Beginning in 2004, this rule accounted for a reduction of approximately thirty-one percent (31%) of all NO_x emissions statewide compared to previous uncontrolled years.

Twenty-one other states have also adopted these rules. The result is that significant reductions have occurred regionally and within the nonattainment area because of the number of affected units within the region. From Graphs 4.13 and 4.14, it can be seen that emissions covered by this program have been trending downward since 1999. Table 6.1, compiled from data taken from the U.S. EPA Clean Air Markets Web site, quantifies the gradual NO_x reductions that have occurred in Indiana as a result of Title IV (Acid Rain) of the CAA and the NO_x SIP Call Rule. The NOx SIP Call cap stayed in place through 2008, at which time the caps in the CAIR program superseded it. Since CAIR is a regional cap and trade program, it cannot be predicted at this time what effect this will have on EGU units located in the nonattainment area or other upwind counties.

Further, U.S. EPA published Phase II of the NO_x SIP Call that establishes a budget for large (emissions of greater than 1 ton per day) stationary internal combustion engines. In Indiana, the rule decreases emissions statewide from natural gas compressor stations by 4,263 tons during the ozone season (May through September). The Indiana Phase II NOx SIP Call Rule became effective February 26, 2006 and implementation began in 2007.

Table 6.1
Trends in EGU NO_x Emissions Statewide in Indiana

Year	NO_x Emissions (tons /year)
1999	347,216.5
2000	334,522.1
2001	315,419.7
2002	281,146.1
2003	260,980.0
2004	224,311.3
2005	207,981.6
2006	202,728.0
2007	196,553.1
2008	196,134.5
2009	110,968.9
Budget 2009-2014	108,935
Budget 2015 and later	90,779

6.4 Measures Beyond CAA SIP Requirements

Reductions in fine particles precursor emissions have occurred, or are anticipated to occur, as a result of local and federal programs. These additional control measures include:

Tier 2 Vehicles Standards[2]

Federal Tier 2 motor vehicle standards require all passenger vehicles in a manufacturer's fleet, including light-duty trucks and sport utility vehicles (SUVs), to meet an average standard of 0.07 grams of NO_x per mile. Implementation began in 2004 and was completed in 2007. The Tier 2 standards also cover passenger vehicles over 8,500 pounds gross vehicle weight rating (larger pickup trucks and SUVs), which are not covered by the current Tier 1 standards. For these vehicles, the standards were phased in beginning in 2008, with full compliance in 2009. The new standards require vehicles to be 77% to 95% cleaner than those on the road prior to the program. The Tier 2 standards also reduced the sulfur content of gasoline to 30 parts per million (ppm) beginning in January 2006. Most gasoline sold in Indiana prior to January 2006 had a sulfur content of about 500 ppm. Sulfur occurs naturally in gasoline, but interferes with the operation of catalytic converters on vehicles resulting in higher NO_x emissions. Lower sulfur gasoline is necessary to achieve the Tier 2 vehicle emissions standards.

Heavy-Duty Gasoline and Diesel Highway Vehicle Standards[3]

New U.S. EPA standards designed to reduce NO_x and VOC emissions from heavy-duty gasoline and diesel highway vehicles took effect in 2004. A second phase of standards and testing procedures that began in 2007, reduced $PM_{2.5}$ emissions from heavy-duty highway engines and also reduced highway diesel fuel sulfur content to 15 ppm since the sulfur can damage emissions control devices. The total program is expected to achieve a 90% reduction in direct $PM_{2.5}$ emissions and a 95% reduction in NO_x emissions for these new engines using low sulfur diesel, compared to existing engines using higher sulfur content diesel. There will also be SO_2 reductions from these rules. The U.S. EPA has not quantified the expected reductions.

Large Nonroad Diesel Engine Standards[4]

In May 2004, U.S. EPA promulgated new rules for large nonroad diesel engines, such as those used in construction, agricultural and industrial equipment, to be phased in between 2008 and 2014. The nonroad diesel rules also reduce the allowable sulfur in nonroad diesel fuel by over 99%. Nonroad diesel fuel currently averages approximately 3,400 ppm sulfur. This rule limits nonroad diesel sulfur content to 500 ppm in 2006 and 15 ppm in 2010. The combined engine and fuel rules will reduce NO_x and $PM_{2.5}$ emissions from large nonroad diesel engines by over 90%, compared to current nonroad engines using higher sulfur content diesel.

Nonroad Spark-Ignition Engines and Recreational Engines Standards

This standard, effective in July 2003, regulates NO_x, VOCs, and carbon monoxide (CO) for groups of previously unregulated nonroad engines. The standard applies to all new engines sold in the United States and imported after the standards went into effect. The standard applies to large spark-ignition engines (forklifts and airport ground service equipment), recreational vehicles (off-highway motorcycles and all-terrain vehicles), and recreational marine diesel engines. The regulation varies based upon the type of engine and vehicle.

[2] http://www.epa.gov/fedrgstr/EPA-AIR/2000/February/Day-10/a19a.htm
[3] http://www.epa.gov/fedrgstr/EPA-AIR/1997/October/Day-21/a27494.htm
[4] http://www.epa.gov/fedrgstr/EPA-AIR/1998/October/Day-23/a24836.htm

The large spark-ignition engines contribute to ozone formation and ambient CO and $PM_{2.5}$ levels in urban areas. Tier 1 of this standard was implemented in 2004 and Tier 2 started in 2007. Like the large spark-ignition engines, recreational vehicles contribute to ozone and fine particles formation and ambient CO and $PM_{2.5}$ levels. For model year 2006 off-highway motorcycles and all-terrain vehicles, at least 50% of a manufacture's fleet was required to meet the new exhaust emissions standard and 100% of the fleet was required to meet the standards in 2007. Recreational marine diesel engines over 37 kilowatts are used in yachts, cruisers and other types of pleasure craft. Recreational marine engines contribute to ozone formation and $PM_{2.5}$ levels, especially surrounding marinas.

When all of the nonroad spark-ignition engines and recreational engine standards are fully implemented, an overall 72% reduction in VOCs, 80% reduction in NO_x, and 56% reduction in CO emissions are expected by 2020.

Reciprocating Internal Combustion Engine Standards[5]
This new standard, effective in May 2010, regulates air toxics emissions from existing diesel powered stationary reciprocating internal combustion engines that meet specific siting, age, and size criteria. These engines are typically used at industrial facilities (e.g. power, chemical, and manufacturing plants) to generate electricity for compressors and pumps and to produce electricity to pump water for flood and fire control during emergencies.

The standard applies to stationary diesel engines: (1) used at area sources of air toxics emissions and constructed or reconstructed before June 12, 2006; (2) used at major sources of air toxics emissions, having a site rating of less than or equal to 500 horsepower, and constructed or reconstructed before June 12, 2006; and, (3) used at major sources of air toxics for non-emergency purposes, having a site rating of greater than 500 horsepower, and constructed or reconstructed before December 19, 2002.

Operators of existing engines will be required to: (1) install emissions control equipment that would limit air toxics up to 70% for stationary non-emergency engines with a site rating greater than 300 horsepower; (2) perform emissions tests to demonstrate engine performance and compliance with rule requirements; and, (3) burn ultra-low sulfur fuel in stationary non-emergency engines with a site rating greater than 300 horsepower.

When all of the reciprocating internal combustion engine standards are fully implemented in 2013, U.S. EPA estimates that emissions from these engines will reduce air toxics by approximately 1,000 tons per year (tpy), $PM_{2.5}$ by 2,800 tpy, carbon monoxide by 14,000 tpy, and volatile organic compounds by 27,000 tpy.

[5] http://www.epa.gov/ttn/atw/rice/fr03mr10.pdf

Category 3 Marine Diesel Engine Standards[6]

This new standard, effective in June 2010, promulgates more stringent exhaust emission standards for new large marine diesel engines with per-cylinder displacement at or above 30 liters (commonly referred to as Category 3 compression-ignition marine engines) as part of a coordinated strategy to address emissions from all ships that affect U.S. air quality. These emission standards are equivalent to those adopted in the amendments to Annex VI to the International Convention for the Prevention of Pollution from Ships (MARPOL Annex VI). The emission standards apply in two stages—near-term standards for newly built engines will apply beginning in 2011; long-term standards requiring an eighty percent (80%) reduction in NO_X emissions will begin in 2016.

U.S. EPA is adopting changes to the diesel fuel program to allow for the production and sale of diesel fuel with up to 1,000 ppm sulfur for use in Category 3 marine vessels. The regulations generally forbid production and sale of fuels with more than 1,000 ppm sulfur for use in most U.S. waters, unless operators achieve equivalent emission reductions in other ways. U.S. EPA is also adopting provisions to apply some emission and fuel standards to foreign-flagged and in-use vessels that are covered by MARPOL Annex VI.

When this strategy is fully implemented in 2030, U.S. EPA estimates that NO_x and PM emissions in the U.S. will be reduced by approximately 1.2 million tpy and 143,000 tpy, respectively.

Clean Air Interstate Rule (CAIR)

On May 12, 2005, the U.S. EPA promulgated the "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call"; Final Rule. (40 CFR Parts 51, 72, 75 and 96) This rule established the requirement for states to adopt rules limiting the emissions of NO_x and SO_2 and provided a model rule for the states to use in developing their rules to meet federal requirements. The purpose of CAIR is to reduce interstate transport of precursors to fine particles and ozone.

CAIR applies to: (1) any stationary fossil-fuel-fired boiler or stationary fossil-fuel-fired combustion turbine, a generator with nameplate capacity of more than 25 megawatt electrical (MWe) producing electricity for sale; and, (2) a unit that qualifies as a cogeneration unit during the 12-month period starting on the date that the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with a nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh (megawatt hours), whichever is greater to any utility power distribution system for sale.

[6] http://www.regulations.gov/search/Regs/home.html#documentDetail?R=0900006480ae43a6

This rule provides annual state caps for NO_x and SO_2 in two phases, with the Phase I caps for NO_x and SO_2 starting in 2009 and 2010, respectively. Phase II caps become effective in 2015. The U.S. EPA is allowing the caps to be met through a cap and trade program if a state chooses to participate in the program.

In response to U.S. EPA's rulemaking, IDEM adopted a state rule in 2006 based on the model federal rule. IDEM's rule includes an annual and seasonal NO_x trading program and an annual SO_2 trading program. This rule requires compliance effective January 1, 2009.

On March 10, 2005, the U.S. EPA finalized CAIR. SO_2 emissions from power plants in the 28 eastern states and the District of Columbia covered by CAIR will be cut by 4.3 million tons by 2009 and reduced by an additional 5.4 million tons in 2015. NO_x emissions will be cut by 1.7 million tons by 2009 and reduced by an additional 1.3 million tons in 2015. The D.C. Circuit court's vacatur of CAIR in July of 2008 and subsequent remand without vacatur of CAIR in December of 2008 directs U.S. EPA to revise/replace CAIR in order to properly address the deficiencies outlined by the court.

Since the court's opinion made it clear that CAIR is deficient and must be revised/replaced, the program cannot be defined as permanent and enforceable for SIP purposes. On July 6, 2010, U.S. EPA proposed the Clean Air Transport Rule to replace CAIR. The Transport Rule will result in even further benefits above and beyond CAIR than what is assumed within the emission inventories and modeling.

Together, these rules will substantially reduce local and regional sources of fine particle precursors. The modeling analyses discussed in Section 7.0 include these rules and show the reductions in annual fine particle concentrations expected to result from the implementation of these rules.

6.5 Controls to Remain in Effect

Indiana commits to maintain the control measures listed above after redesignation, or submit to U.S. EPA, as a SIP revision, any changes to its rules or emission limits applicable to NO_x, SO_2, or direct $PM_{2.5}$ sources as required for maintenance of the annual standard for fine particles in Dearborn County, Indiana.

Indiana, through IDEM's Office of Air Quality and its Compliance and Enforcement Branch, has the legal authority and necessary resources to actively enforce any violations of its rules or permit provisions. After redesignation, it intends to continue enforcing all rules that relate to the emission of fine particles and fine particle precursors in Dearborn County, Indiana.

6.6 New Source Review Provisions

Indiana has a long standing and fully implemented New Source Review (NSR) program that is outlined at 326 IAC 2. The rule includes provisions for the Prevention of Significant Deterioration (PSD) permitting program in 326 IAC 2-2. Indiana's PSD program was

conditionally approved on March 3, 2003 (68 FR 9892) and received final approval on May 20, 2004 (69 FR 29071) by U.S. EPA as part of the SIP.

Any facility that is not listed in the 2005 emission inventory, or for which credit through the shutdown or curtailment was taken in demonstrating attainment, will not be allowed to construct, reopen, modify, or reconstruct without meeting all applicable permit rule requirements. The review process will be identical to that used for new sources. Once the area is redesignated, OAQ will implement NSR through the PSD program, which requires an air quality analysis to evaluate whether the new source will threaten the NAAQS.

7.0 MODELING AND METEOROLOGY

Although U.S. EPA Redesignation Guidance does not require modeling for nonattainment areas seeking redesignation, extensive modeling has been performed covering the Cincinnati, Ohio region to determine the effect of national emission control strategies on fine particle levels. These modeling analyses determined that the Cincinnati area, including Dearborn County in southeastern Indiana is significantly impacted by regional transport of fine particles and its precursors, and that regional SO_2 and NO_x reductions are an effective way to attain the annual standard for fine particles in this area. Future year modeled annual fine particle concentrations are expected to be reduced by 0.6 to 1.3 $\mu g/m^3$. Examples of these modeling analyses are described below.

7.1 Summary of Modeling Results to Support Rulemakings

U.S. EPA Modeling for Transport Rule, 2010

U.S. EPA performed modeling to support the emission reductions associated with the Transport Rule. U.S. EPA used Comprehensive Air Quality Model with Extension (CAMx, Version 5), applied to the 2005 meteorology, as processed by the Mesoscale Model (MM5), Version 3.7.4. Emissions input into CAMx included SO_2, NO_x, volatile organic compounds (VOC), ammonia, and direct $PM_{2.5}$ for 2005. The modeling was based on the annual fine particles design values calculated from 2003 through 2005, 2004 through 2006, and 2005 through 2007. Future year modeling was conducted, which included the Cincinnati area, and the future year design values for 2012 and 2014 were evaluated for attainment of the annual NAAQS for fine particles of 15 $\mu g/m^3$, as shown in Table 7.1. Fine particle concentrations are accounted for by modeling both the base future year emissions and then the emissions reductions associated with the Transport Rule. U.S. EPA found model performance met suggested benchmark performance goals within or close to the ranges found in other comparable modeling applications (Technical Support Document for the Transport Rule – Air Quality Modeling).

[7] http://www.epa.gov/airquality/transport/pdfs/TR_AQModeling_TSD.pdf

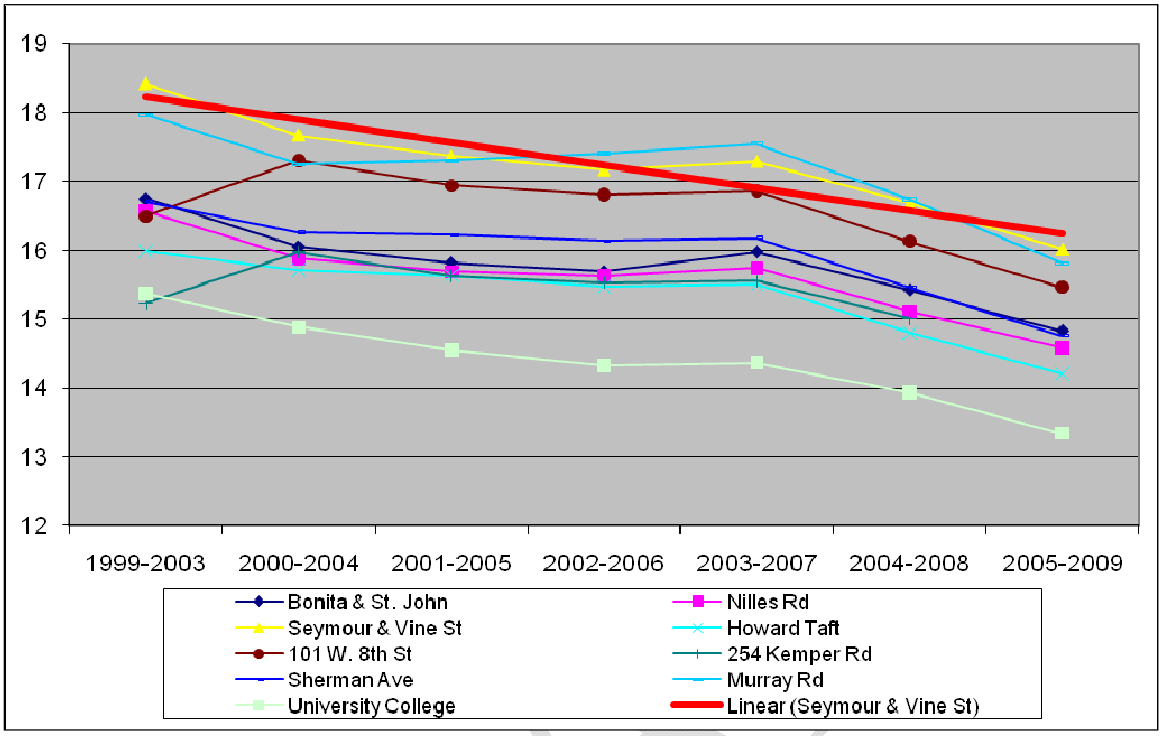
Table 7.1
Transport Rule Modeling Results from U.S. EPA – 2010

County	Monitor ID	Design Value 2003-2007 ($\mu g/m^3$)	Future Design Value 2012 Base ($\mu g/m^3$)	Future Design Value 2014 Base ($\mu g/m^3$)
Butler County	39-017-0016	15.74	15.25	14.76
Butler County	39-017-0017	15.36	14.93	14.48
Butler County	39-017-1004	14.90	14.51	14.06
Hamilton County	39-061-0006	14.84	14.36	13.88
Hamilton County	39-061-0014	17.29	16.69	16.14
Hamilton County	39-061-0040	15.50	15.03	14.51
Hamilton County	39-061-0042	16.85	16.33	15.80
Hamilton County	39-061-0043	15.55	15.05	14.56
Hamilton County	39-061-7001	16.17	15.65	15.12
Hamilton County	39-061-8001	17.54	16.93	16.38
Campbell County	21-037-0003	13.67	13.30	12.81
Kenton County	21-117-0007	14.36	13.98	13.50

Modeling results show that the base future year modeling with emission reductions from the Transport Rule accounts for approximately 0.4 to 0.6 $\mu g/m^3$ decreases in concentrations for 2012 and approximately 0.8 to1.2 $\mu g/m^3$ decreases in concentrations for 2014 in the Cincinnati area.

While results of U.S. EPA's Transport Rule modeling show modeled concentrations above the standard using base case emissions at several $PM_{2.5}$ monitoring sites in Hamilton County, Ohio, it should be noted that base year design value used by U.S. EPA was taken from 2003 through 2007 and considered higher than current 2005 through 2009 design values in the area. Graph 7.1 shows the downward trend of the design values from 1999 through 2009 for the $PM_{2.5}$ monitors in the Cincinnati area. The resulting decreases of the 2003 through 2007 design values to the 2005 through 2009 design value at the Murray Road $PM_{2.5}$ monitor is 1.75 $\mu g/m^3$, the decrease at the Seymour and Vine Street monitor is 1.27 $\mu g/m^3$ and 1.39 $\mu g/m^3$ at the West 8th Street monitor. The results decrease from all the area monitors ranged from 1.05 $\mu g/m^3$ to 1.75 $\mu g/m^3$. Therefore, U.S. EPA's Transport Rule modeling, using current 2005 through 2009 design values, would show lower modeled concentrations approaching the annual fine particle standard of 15.0 $\mu g/m^3$.

Graph 7.1
$PM_{2.5}$ Design Value Trends for Cincinnati Area: 1999 - 2009



Results of the U.S. EPA Transport Rule modeling show that the Cincinnati area will approach the annual fine particles NAAQS in 2012 with modeled impacts reduced by 3% to 4%. The 2014 projected design values will decrease by 6% to 7% from the 2003 through 2007 design values. If using current design values, U.S. EPA's CAIR modeling would show the Cincinnati area would approach the current annual fine particles standard.

LADCO Modeling for CAIR

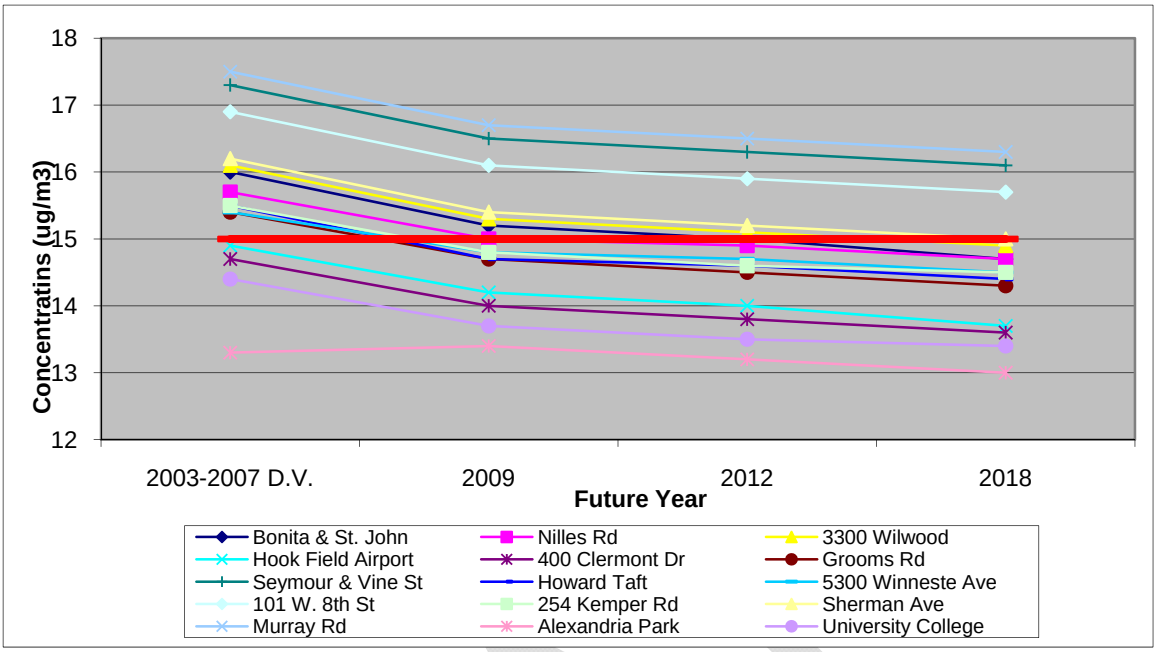
LADCO conducted modeling to determine the impact of CAIR in the Midwest. LADCO's modeling used the CAMx model applied to the year 2005 meteorology, as processed by the MM5. Emissions input into CAMx included SO_2, NO_x, VOC, ammonia, and direct $PM_{2.5}$ for 2005. The modeling was based on 2003 through 2007 design values. Future year modeling for 2009, 2012, and 2018 was conducted and the future year design values were determined without the emission reductions associated with CAIR (Round 6), as shown in Table 7.2.

Table 7.2
LADCO's Round 6 Modeling Results for the Cincinnati Area

Monitor ID	Monitor Name	County	Design Value 2003-2007	Base-case 2012	Base-case 2018
			(µg/m^3)	(µg/m^3)	(µg/m^3)
390170003	Bonita & St. John	Butler	16.0	15.0	14.7
390170016	Nilles Rd	Butler	15.7	14.9	14.7
390170017	3300 Wilwood	Butler	16.1	15.1	14.9
390171004	Hook Field Airport	Butler	14.9	14.0	13.7
390250022	400 Clermont Dr	Clermont	14.7	13.8	13.6
390610006	Grooms Rd	Hamilton	15.4	14.5	14.3
390610014	Seymour & Vine St	Hamilton	17.3	16.3	16.1
390610040	Howard Taft	Hamilton	15.5	14.6	14.4
390610041	5300 Winneste Ave	Hamilton	15.4	14.7	14.5
390610042	101 W. 8th St	Hamilton	16.9	15.9	15.7
390610043	254 Kemper Rd	Hamilton	15.5	14.6	14.5
390617001	Sherman Ave	Hamilton	16.2	15.2	15.0
390618001	Murray Rd	Hamilton	17.5	16.5	16.3
210370003	Alexandria Park	Campbell	13.3	13.2	13.0
211170007	University College	Kenton	14.4	13.5	13.4

Results of the LADCO Round 6 modeling show that all but five of the fifteen monitors in the Cincinnati area continue to attain the annual NAAQS for fine particles of 15 µg/m^3 in 2012. Modeled concentrations at the five fine particle monitors, Murray Road, Seymour & Vine Street, Wilwood, Sherman Avenue and West 8th Street were above the fine particles standard. Table 7.2 shows future year modeled annual fine particle results without CAIR emission reductions. Concentrations for 2009 will be 5% to 6% lower than baseline annual fine particles design values, 6% to 8% lower in 2018. A graphical representation of the modeling results is shown in Graph 7.2. Modeled results for the Cincinnati area would approach the current annual fine particle standard would be lower if the current 2005 through 2009 design values, as shown in Graph 7.1, were used.

Graph 7.2
Modeling Results (without CAIR) for the Cincinnati Area $PM_{2.5}$ Monitors



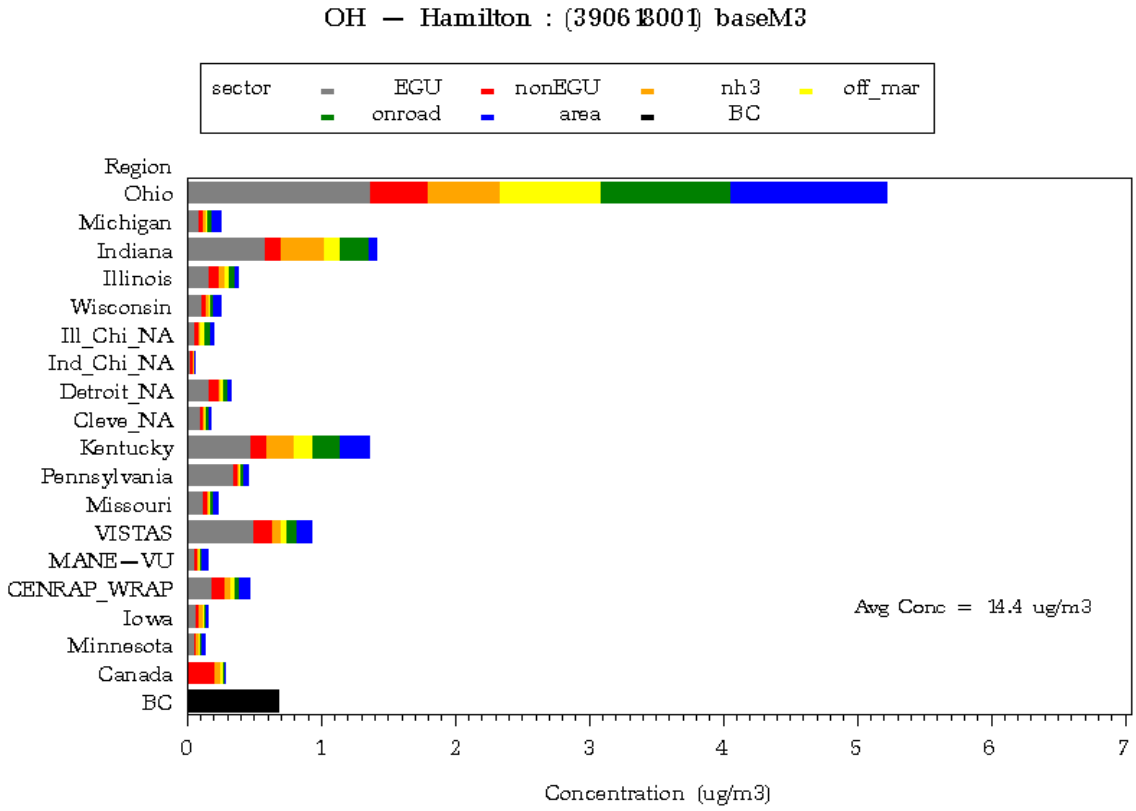
7.2 LADCO's Round 5 Particulate Source Apportionment Results

Particulate Source Apportionment (PSAT) modeling was conducted by LADCO. The results of the PSAT Round 5 modeling shows the regional contributions by emission sectors on each monitor that was modeled. Chart 7.1 shows the PSAT modeling results for the Murray Road fine particles monitor in Hamilton County in southwest Ohio. Ohio was the biggest regional contributor to the Murray Road fine particles monitor with Indiana, Kentucky, the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) Regional Planning Organization (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia and West Virginia and the Eastern Band of the Cherokee Indians), the Central Regional Air Planning Association (CENRAP) Regional Planning Organization (Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana), the Western Regional Air Partnership (WRAP) Regional Planning Organization (Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, Wyoming) and Pennsylvania also contributing.

The sector emissions are described as EGU, non-EGU, NH_3 – ammonium emission sources, offroad emission sources including marine, air travel and railroad emission sources, onroad mobile emission sources, area, and boundary conditions.

The PSAT modeling results show the majority of Indiana's emission sector contributions come from EGUs, ammonium, onroad, offroad (including marine, aircraft and railroad), non-EGU, and area sources. Other contributions resulted mainly from EGU, non-EGU, and ammonium emissions from other regional areas.

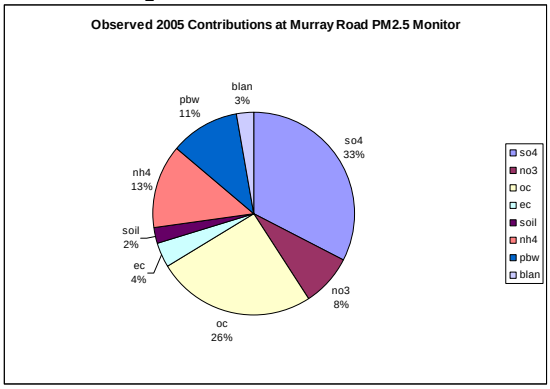
Chart 7.1
Regional/Emission Sector PSAT Results at Murray Road in Hamilton County



The following pie charts depict the species contributions to fine particle concentrations at the Cincinnati area monitors. The pie charts include both the observed 2005 contributions and future year 2009 modeled contributions for each monitor. Since the monitors are in close proximity of each other, results are fairly similar in the distribution of species concentrations among the monitors. Charts 7.2 through 7.5 cover the three fine particle monitors in southwestern Ohio and one fine particles monitor in northern Kentucky with the highest concentrations used to determine compliance with the annual fine particles NAAQS of 15 $\mu g/m^3$.

The speciation listed in the pie charts include SO_4 – sulfate mass, NO_3 – nitrate mass, OC – organic carbon mass, EC – elemental carbon mass, Soil – crustal material mass, NH_4 – ammonium mass, PBW – particles bound water mass, BLAN – passively collected mass.

Chart 7.2
Species Modeled Contributions to Murray Road $PM_{2.5}$ Monitor



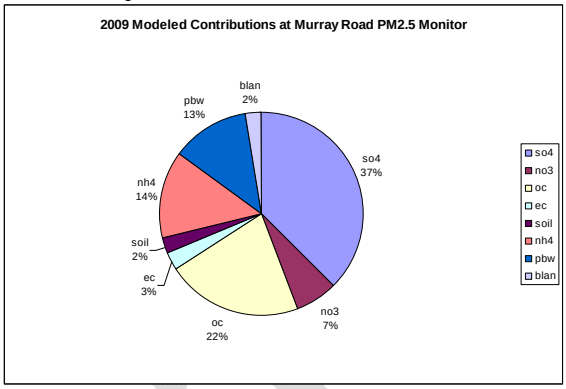
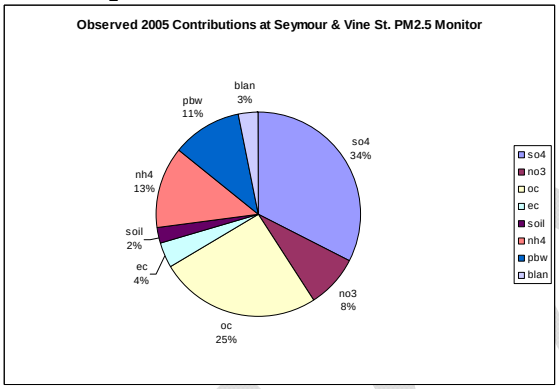


Chart 7.3
Species Modeled Contributions to Seymour & Vine St. $PM_{2.5}$ Monitor



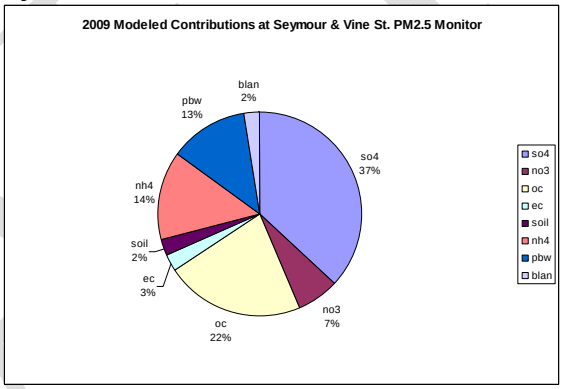
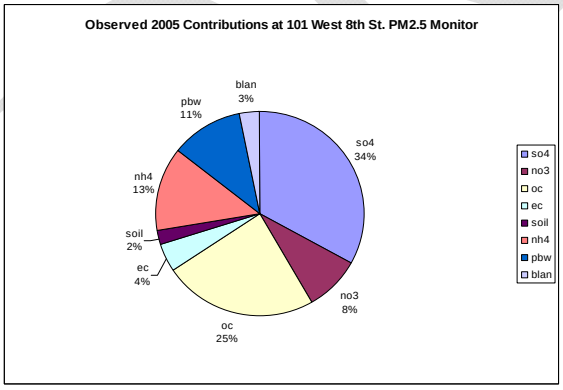


Chart 7.4
Species Modeled Contributions to 101 West 8th Street $PM_{2.5}$ Monitor



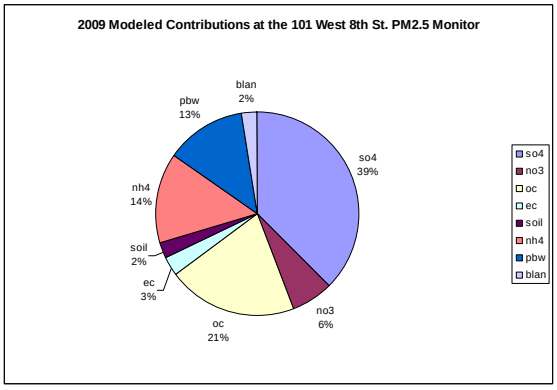
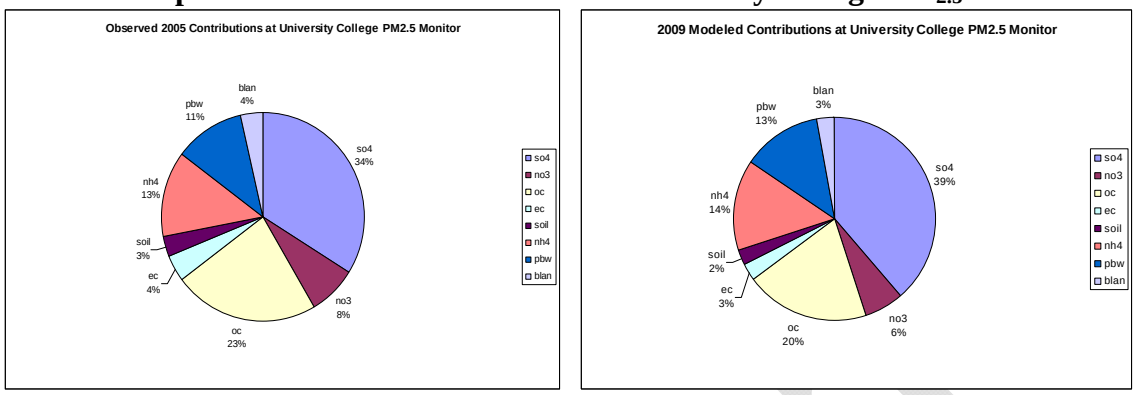


Chart 7.5
Species Modeled Contributions to University College $PM_{2.5}$ Monitor



Results of the Round 5 PSAT modeling for the Cincinnati area fine particle monitors show the highest pollutant contributors to base case and future year fine particle concentrations are sulfate, organic carbon, ammonium and nitrate. Future year modeling shows decreases in organic carbon, nitrates and elemental carbon. The future year modeling did show increases in sulfates, particles bound water and ammonium from the base-case modeled concentrations.

7.3 Summary of Existing Modeling Results

U.S. EPA and LADCO modeling for future year design values have consistently shown that existing national emission control measures will help the Cincinnati area approach attainment of the annual NAAQS for fine particles standard of 15 $\mu g/m^3$. Emission control measures to be implemented in the next several years will help air quality meet the standard in the future. U.S. EPA future year modeling of national emission control strategies, based on current design values, showed the Cincinnati area will approach the annual NAAQS for fine particles. Future national and local emission control strategies will ensure that the Cincinnati fine particles nonattainment area will maintain the lower fine particle concentrations.

7.4 Meteorological Analysis for Southeastern Indiana

Meteorological conditions are one of the most important factors that influence development and transport of fine particles. Stagnant surface conditions and upper air ridging during any time of the year provides conducive conditions for development and transport of fine particles. Ultimately, passage of surface cold fronts with a clean air mass change will lower fine particle readings in the Cincinnati area.

7.4.1 Surface Air Conditions Present during High Fine Particles Concentrations Days

Higher annual concentrations of fine particles tend to correlate with warmer temperatures and lighter wind speeds, although high fine particle episodes can occur in the summer fall, winter or spring. It should be noted that higher annual fine particle concentrations are driven by individual days with higher fine particle concentrations throughout the monitored year. Therefore, it is difficult to attribute higher fine particle concentrations to annualized meteorological rankings. Review of several of the higher fine particles concentration episodes (days with concentrations

over 35 $\mu g/m^3$) over the past few years shows conditions were hot in the summer with temperatures in the middle 80^o Fahrenheit or higher and average wind speeds were fairly light. Fall and winter high fine particles concentration days had near normal temperatures but very light wind speeds with higher humidity. Surface conditions present for higher fine particle days had a high pressure system east of the Cincinnati area with a front located either north or west of the area.

Analysis of the Murray Road $PM_{2.5}$ monitor data on the higher concentration days showed over 60% occurred with maximum temperatures above 80^o F and only 5% of the high concentration days occurred at maximum temperatures below 40^o F. The location of this monitor is considered downwind of the urban center of Cincinnati so the urban emissions are transported to the monitor. However, surface meteorological conditions would also play a large role in increased fine particle readings at the monitor.

7.4.2 Upper Air Conditions Present during High Fine Particles Concentrations Days

Upper air ridges and more stagnant surface wind conditions predominately affect development and build up of fine particles. Slow moving upper air ridges can effectively suppress mixing within the many levels of the atmosphere and cause pollutants to build up over time. Inversions or increases in temperature with a rise in altitude will prevent mixing with air from the upper atmosphere. These conditions can occur at any time of the year and are evident in elevated fine particle episodes in spring, summer, fall and winter months. Review of upper air features present during higher concentration days in the Cincinnati area during the summer showed generally a ridge over the area with fairly light winds in the upper atmosphere and warm air advection. The upper air features present during higher concentration days in the fall and winter were upper air troughs with extremely light winds and moderate temperatures.

Review of surface and upper air features of higher fine particles concentration days showed stagnant surface conditions and upper air ridges existed on those days. These conditions help in the buildup of fine particle concentrations in the Cincinnati area.

7.4.3 Analyses of Atmospheric Conditions for Fine Particles Build-Up

Analyses have been conducted to determine the atmospheric conditions that are most prevalent during higher fine particles concentration days in Indiana. LADCO applied a Classification and Regression Tree (CART) analysis to data from Indiana that correlated different levels of fine particle concentrations to meteorological conditions from 1999 through 2004. (Donna Kenski, 2005). This type of analysis looks at the meteorological conditions, such as temperature, pressure, wind speed, wind direction, relative humidity and dew point temperatures at the surface, as well as lower morning and evening mixing heights in the upper atmosphere which were present when higher concentrations of fine particles were monitored. Results of this CART analysis indicated factors that played a larger role in fine particle concentrations in the southern portion of the Midwest were warm-weather conditions with high dew points, southwest winds and low evening mixing heights as well as the previous day's concentrations of fine particles.

Fine particles are made up of several constituents, including direct $PM_{2.5}$, sulfates, nitrates, ammonium, organic carbon and elemental carbon. Depending on the time of the year, concentrations of particulate constituents vary, with nitrates being more prevalent in the winter and sulfates more prevalent in the summer. Sulfates and nitrate emission reductions have the biggest impact on lower future year fine particle concentrations.

7.5 Summary of Air Quality Index Days in Southeastern Indiana

An analysis was conducted to review the daily fine particle concentrations over a year to determine the Air Quality Index (AQI) trends. Chart 7.6 shows by year (2000 through 2009), the percentage number of days during which fine particle concentrations reached the AQI ranges for "Good" (0 to 15.3 $\mu g/m^3$), "Moderate" (15.4 $\mu g/m^3$ to 40.4 $\mu g/m^3$) and "Unhealthy for Sensitive Groups (USG)" (40.5 $\mu g/m^3$ to 65.4 $\mu g/m^3$) at the Murray Road $PM_{2.5}$ monitor in Hamilton County in Ohio. There were no days which the fine particle levels reached the "Unhealthy" level of 65.5 $\mu g/m^3$ to 150.4 $\mu g/m^3$ or above.

Chart 7.6
Distribution of $PM_{2.5}$ Concentration Days on the AQI Levels of Health Concern

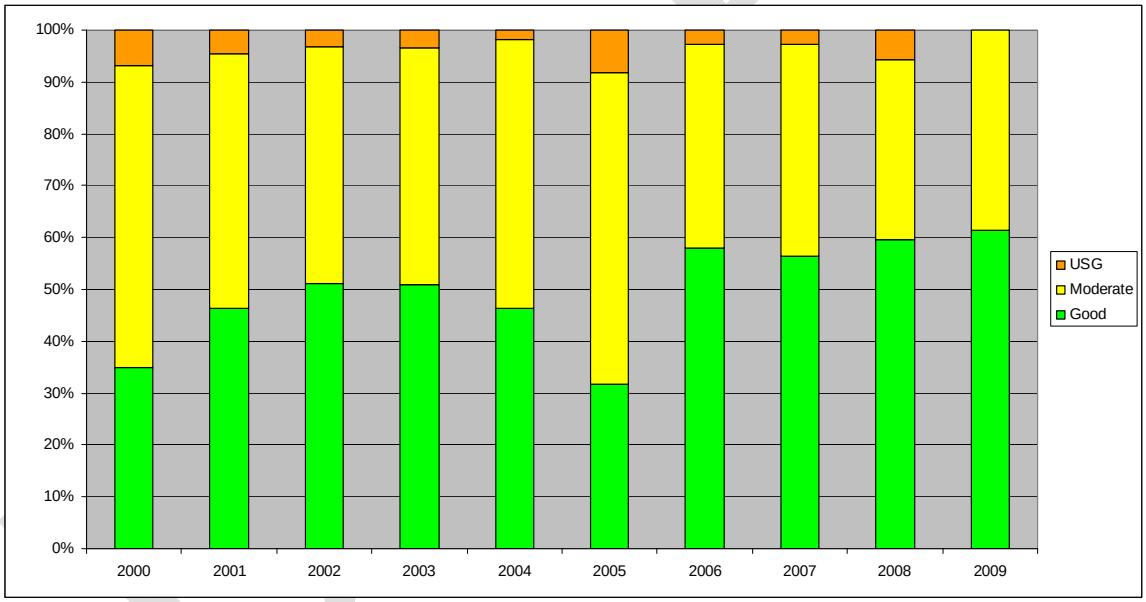


Table 7.3 shows the rankings, by year, for the three AQI ranges. The year 2009 had the most "Good" concentration days during the 10-year period analyzed (2000 through 2009) at 61%. The year 2005 had the most "Moderate" concentrations days at 60% and "Unhealthy for Sensitive Group" concentration days at 8%. As can be seen, weather plays a large role in fine particle concentrations development and transport as 2000, 2001, 2004 and 2005 were conducive to $PM_{2.5}$ development which translated to moderate and unhealthy for sensitive group levels of air quality over 50% of the time.

Table 7.3
Ranking and Percentage of Highest Number of Days
at AQI Levels of Health Concern

Ranking	Good	Moderate	Unhealthy for Sensitive Group
1st	**2009** – 61%	**2005** – 60%	**2005** – 8%
2nd	**2008** – 60%	**2000** – 58%	**2000** – 7%
3rd	**2006** – 58%	**2004** – 52%	**2008** – 6%
4th	**2007** – 56%	**2001** – 49%	**2001** – 5%
5th	**2002** – 51%	**2003** – 46%	**2003** – 3%
6th	**2003** – 51%	**2002** – 45%	**2002** – 3%
7th	**2001** – 46%	**2007** – 41%	**2007** – 3%
8th	**2004** – 46%	**2006** – 39%	**2006** – 3%
9th	**2000** – 35%	**2009** – 39%	**2004** – 2%
10th	**2005** – 32%	**2008** – 35%	**2009** – 0%

7.6 Summary of Meteorological Analysis for Southeastern Indiana

Annual fine particle concentrations in the Cincinnati area are driven by higher fine particles concentration days that can occur during any time of the year. Conditions that are most prevalent during higher fine particle concentration days are lighter winds, higher relative humidity and above average maximum temperatures in the summer and lighter winds, higher relative humidity and normal temperatures in the fall, winter or spring. Upper air weather patterns generally include ridging over the area with stagnant conditions at the surface caused by lower mixing heights and stable conditions for summer episodes and ridging or troughs over the area in the fall, winter or spring episodes. Surface winds from any direction can transport pollutants from surrounding areas into the Cincinnati area. Nitrates are bigger contributors to fine particle concentrations in the winter and sulfates are bigger contributors to fine particle concentrations in the summer.

8.0 CORRECTIVE ACTIONS

8.1 Commitment to Revise Plan

As noted in Section 4.6 above, Indiana commits to review and revise as appropriate its Maintenance Plan eight years after redesignation, as required by Section 175A of the CAA.

8.2 Commitment for Contingency Measures

IDEM will monitor fine particle concentrations to determine whether trends indicate higher values or whether emissions appear to be increasing. If it is determined that fine particle levels and emissions are increasing and action is necessary to reverse that trend, IDEM will take action to reverse the noted trend, prior to a violation of the standard occurring.

Indiana commits to adopt and expeditiously implement necessary corrective action in the following circumstance:

Action Level Response

An Action Level Response shall be prompted whenever a violation of the standard (three year average annual arithmetic mean value of 15.1 $\mu g/m^3$ or greater) occurs. In the event that the Action Level is triggered and is not found to be due to an atypical unfavorable meteorological condition, exceptional event, malfunction or noncompliance with a permit condition or rule requirement, IDEM will determine additional control measures needed to assure future attainment of the annual NAAQS for fine particles. In this case, measures that can be implemented in a short time will be selected in order to be in place within eighteen months from the close of the fine particles season that prompted the Action Level.

Control Measure Selection and Implementation

Adoption of any additional control measures is subject to the necessary administrative and legal processes. This process will include publication of notices, an opportunity for public hearing and other measures required by Indiana law for rulemaking by state environmental boards.

If a new measure or control is already promulgated and scheduled to be implemented at the federal or state level, and that measure or control is determined to be sufficient to address the upward trend in air quality, additional local measures may be unnecessary. Furthermore, IDEM will submit to U.S. EPA an analysis to demonstrate the proposed measures are adequate to return the area to attainment.

8.3 Contingency Measures

Contingency measures to be considered will be selected from a comprehensive list of measures deemed appropriate and effective at the time the selection is made. Listed below are example measures that may be considered. The selection of measures will be based upon cost-effectiveness, emission reduction potential, economic and social considerations, or other factors that IDEM deems appropriate. IDEM will solicit input from interested and affected persons in the maintenance area prior to selecting appropriate contingency measures. All of the listed contingency measures are potentially effective or proven methods of obtaining significant reductions of fine particles precursor emissions. Because it is not possible at this time to determine what control measure will be appropriate at an unspecified time in the future, the list of contingency measures outlined below is not comprehensive. IDEM anticipates that if contingency measures should ever be necessary, it is unlikely that a significant number (i.e., all those listed below) will be required.

1) Vehicle inspection and maintenance program.
2) Alternative fuel and diesel retrofit programs for fleet vehicle operations.
3) Require NO_x or SO_2 emission offsets for new and modified major sources.

4) Require NO_x or SO_2 emission offsets for new and modified minor sources.
5) Increase the ratio of emission offsets required for new sources.
6) Require NO_x or SO_2 controls on new minor sources (less than 100 tons).
7) Wood stove change-out program.
8) Require increased recovery efficiency at sulfur recovery plants.
9) Various emissions reduction measures or dust suppressant for unpaved roads and/or parking lots.
10) Idling Restrictions.
11) Broader geographic applicability of existing measures.
12) One or more transportation control measures sufficient to achieve at least a half a percent (0.5%) reduction in actual area-wide precursor emissions. Transportation measures will be selected from the following, based upon the factors listed above, after consultation with affected local governments:
    a) Trip reduction programs, including, but not limited to, employer-based transportation management plans, area wide rideshare programs, work schedule changes and telecommuting.
    b) Transit improvements.
    c) Traffic flow improvements.
    d) Other new or innovative transportation measures not yet in widespread use that affect state and local governments deemed appropriate.

No contingency measure shall be implemented without providing the opportunity for full public participation during which the relative costs and benefits of individual measures, at the time they are under consideration, can be fully evaluated.

9.0 PUBLIC PARTICIPATION

This section will be finalized upon completion of the public hearing and public comment period.

10.0 CONCLUSIONS

Lawrenceburg Township, Dearborn County, Indiana, has attained the annual NAAQS for fine particles and does not significantly contribute to violations outside its portion of the Cincinnati-Hamilton OH-KY-IN nonattainment area. This petition demonstrates that Lawrenceburg Township, Dearborn County, Indiana, has complied with the applicable provisions of the CAA regarding redesignation of nonattainment areas for fine particles. IDEM has prepared a State Implementation and Maintenance Plan that meets the requirement of Section 110(a)(1) of the CAA.

Indiana has performed an analysis that shows the air quality improvements are due to permanent and enforceable measures and that additional significant regional NO_x and SO_2 reductions following implementation of Phase II NO_x SIP Call and CAIR and/or its replacement rule or program will ensure continued compliance (maintenance) with the standard. Furthermore, emission projections indicate that NO_x and SO_2 emissions will continue to decline, thus ensuring

that the area continues to maintain compliance with the standard and provide for an increasing margin of safety. Based on this presentation, Lawrenceburg Township, Dearborn County, Indiana, meets the requirements for redesignation under the CAA (Section 107(d)(3)) and U.S. EPA guidance for fine particles.

Consistent with the authority granted to the U.S. EPA, the State of Indiana requests that Lawrenceburg Township, Dearborn County, Indiana, be redesignated to attainment for the annual fine particles standard simultaneously with U.S. EPA approval of this Indiana State Implementation and Maintenance Plan provisions contained herein.

APPENDIX A

Air Quality System (AQS) and Indiana Department of Environmental Management (IDEM) Monitor Data Values for the Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (2000-2009)

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Monitoring Data for the Cincinnati-Hamilton, OH-KY-IN Nonattainment Area						
SITE ID	**STATE**	**COUNTY**	**SITE NAME**	**YEAR**	**Annual Average µg/m3**	**2007-2009 Average µg/m3**
21-037-3002	Kentucky	Campbell	John Hill Rd.	2007	14.36	
21-037-3002	Kentucky	Campbell	John Hill Rd.	2008	11.83	
21-037-3002	Kentucky	Campbell	John Hill Rd.	2009	11.34	**12.51**
21-117-0007	Kentucky	Kenton	Univ. College	2007	14.20	
21-117-0007	Kentucky	Kenton	Univ. College	2008	11.99	
21-117-0007	Kentucky	Kenton	Univ. College	2009	11.04	**12.41**
39-017-0003	Ohio	Butler	Bonita & St. John	2007	15.41	
39-017-0003	Ohio	Butler	Bonita & St. John	2008	13.69	
39-017-0003	Ohio	Butler	Bonita & St. John	2009	12.68	**13.93**
39-017-0016	Ohio	Butler	Niles Rd.	2007	14.94	
39-017-0016	Ohio	Butler	Niles Rd.	2008	13.75	
39-017-0016	Ohio	Butler	Niles Rd.	2009	13.08	**13.92**
39-017-1004	Ohio	Butler	Hook Fld. Airport	2007	14.63	
39-017-1004	Ohio	Butler	Hook Fld. Airport	2008		
39-017-1004	Ohio	Butler	Hook Fld. Airport	2009		**N/A**
39-025-0022	Ohio	Clermont	Clermont Dr.	2007	14.01	
39-025-0022	Ohio	Clermont	Clermont Dr.	2008	11.75	
39-025-0022	Ohio	Clermont	Clermont Dr.	2009	11.01	**12.26**
39-061-0006	Ohio	Hamilton	Grooms Rd.	2007	14.63	
39-061-0006	Ohio	Hamilton	Grooms Rd.	2008	12.48	
39-061-0006	Ohio	Hamilton	Grooms Rd.	2009	12.11	**13.07**
39-061-0014	Ohio	Hamilton	Seymour & Vine St.	2007	16.59	
39-061-0014	Ohio	Hamilton	Seymour & Vine St.	2008	15.12	
39-061-0014	Ohio	Hamilton	Seymour & Vine St.	2009	13.40	**15.04**
39-061-0040	Ohio	Hamilton	Howard Taft	2007	15.09	
39-061-0040	Ohio	Hamilton	Howard Taft	2008	12.62	
39-061-0040	Ohio	Hamilton	Howard Taft	2009	12.73	**13.48**
39-061-0042	Ohio	Hamilton	W. 8th St.	2007	15.90	
39-061-0042	Ohio	Hamilton	W. 8th St.	2008	14.40	
39-061-0042	Ohio	Hamilton	W. 8th St.	2009	13.71	**14.67**
39-061-0043	Ohio	Hamilton	Kemper Rd.	2007	14.85	
39-061-0043	Ohio	Hamilton	Kemper Rd.	2008	13.32	
39-061-0043	Ohio	Hamilton	Kemper Rd.	2009		**N/A**
39-061-7001	Ohio	Hamilton	Sherman Ave.	2007	15.09	
39-061-7001	Ohio	Hamilton	Sherman Ave.	2008	13.74	
39-061-7001	Ohio	Hamilton	Sherman Ave.	2009	12.97	**13.93**
39-061-8001	Ohio	Hamilton	Murray Rd.	2007	16.07	
39-061-8001	Ohio	Hamilton	Murray Rd.	2008	14.40	
39-061-8001	Ohio	Hamilton	Murray Rd.	2009	13.44	**14.64**
39-165-0007	Ohio	Warren	Southeast St.	2007	13.98	
39-165-0007	Ohio	Warren	Southeast St.	2008	11.92	
39-165-0007	Ohio	Warren	Southeast St.	2009	11.70	**12.53**
Valued Above the Annual $PM_{2.5}$ Standard						

Monitoring Data for the Cincinnati-Hamilton, OH-KY-IN Nonattainment Area

Site ID	County	Site Name	Yearly Annual Means									
			2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
21-037-0003	Campbell	Alexandria Park	15.09	13.44	14.81	13.42	12.77	14.84	11.54			
21-037-3002	Campbell	John Hill Rd.								14.36	11.83	11.34
21-117-0007	Kenton	Univ. College	16.26	15.25	15.06	14.30	13.42	15.86	13.29	14.20	11.99	11.04
39-017-0003	Butler	Bonita & St. John	16.96	16.43	16.83	15.05	14.06	19.04	14.05	15.41	13.69	12.68
39-017-0016	Butler	Nilles Rd.	18.85	15.87	15.34	15.83	14.65	17.88	13.99	14.94	13.75	13.08
39-017-0017	Butler	Wilwood	17.93	15.79	15.51	14.66	14.20	17.23				
39-017-1004	Butler	Hook Field Airport		11.62	13.85	14.99	13.57	16.87	13.38	14.63		
39-025-0022	Clermont	Clermont Dr.						15.73	12.72	14.01	11.75	11.01
39-061-0006	Hamilton	Grooms Rd.						16.61	13.29	14.63	12.48	12.11
39-061-0014	Hamilton	Seymour & Vine S	19.25	18.16	17.89	16.95	15.91	19.75	15.51	16.59	15.12	13.40
39-0610040	Hamilton	Howard Taft	16.72	15.93	15.29	15.50	14.63	17.53	13.57	15.09	12.62	12.73
39-061-0041	Hamilton	Winneste Ave.	15.88	16.11	15.10	15.30	14.63	15.77				
39-061-0042	Hamilton	W. 8th St	20.61	17.63	16.83	16.69	15.99	19.09	14.94	15.90	14.40	13.71
39-061-0043	Hamilton	Kemper Rd.	19.10	16.07	15.42	15.67	14.92	16.89	14.47	14.85	13.32	
39-061-7001	Hamilton	Sherman Ave.	17.24	16.76	16.08	16.01	15.33	18.37	14.37	15.09	13.74	12.97
39-061-8001	Hamilton	Murray Rd.	19.27	17.02	16.98	17.31	16.39	20.00	15.90	16.07	14.40	13.44
39-165-0007	Warren	Southeast St.								13.98	11.92	11.70

Value above the annual $PM_{2.5}$ standard.

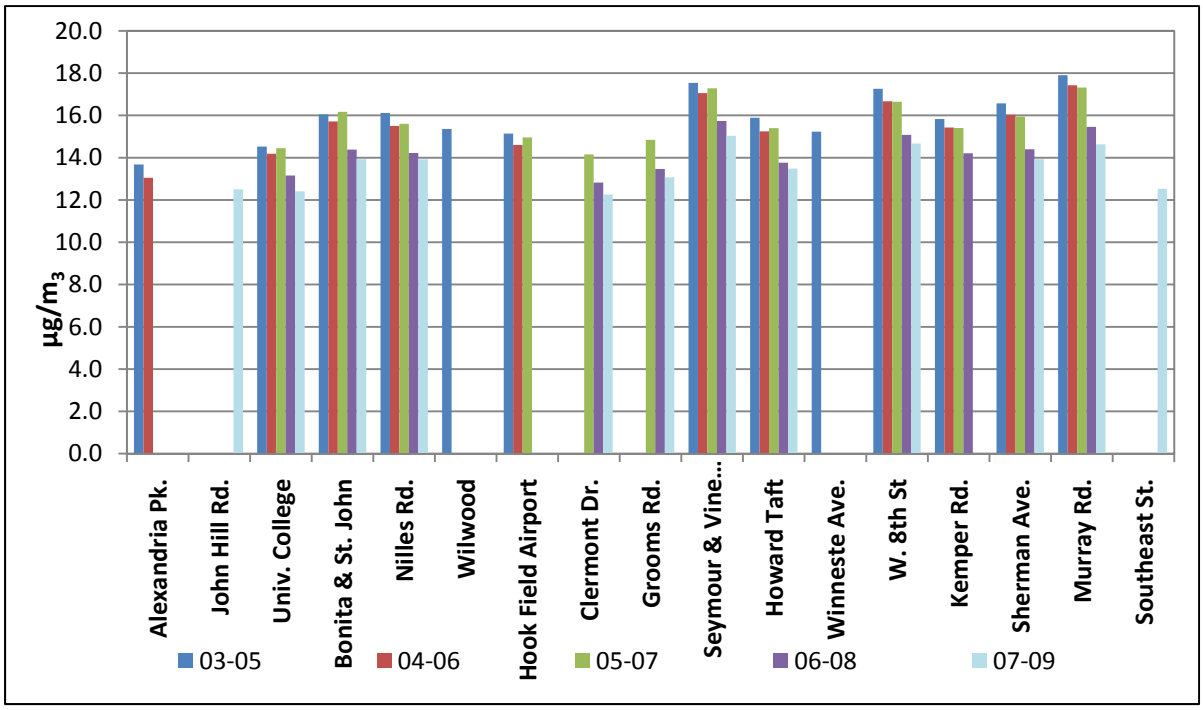
Monitoring Data for the Cincinnati-Hamilton, OH-KY-IN Nonattainment Area

Site ID	County	Site Name	Three Year Design Values							
			00-02	01-03	02-04	03-05	04-06	05-07	06-08	07-09
21-037-0003	Campbell	Alexandria Park	14.4	13.9	13.7	13.7	13.1			
21-037-3002	Campbell	John Hill Rd.								12.5
21-117-0007	Kenton	Univ. College	15.5	14.9	14.3	14.5	14.2	14.5	13.2	12.4
39-017-0003	Butler	Bonita & St. John	16.7	16.1	15.3	16.1	15.7	16.2	14.4	13.9
39-017-0016	Butler	Nilles Rd.	16.7	15.7	15.3	16.1	15.5	15.6	14.2	13.9
39-017-0017	Butler	Wilwood	16.4	15.3	14.8	15.4				
39-017-1004	Butler	Hook Field Airport		13.5	14.1	15.1	14.6	15.0		
39-025-0022	Clermont	Clermont Dr.						14.2	12.8	12.3
39-061-0006	Hamilton	Grooms Rd.						14.8	13.5	13.1
39-061-0014	Hamilton	Seymour & Vine St.	18.4	17.7	16.9	17.5	17.1	17.3	15.7	15.0
39-0610040	Hamilton	Howard Taft	16.0	15.6	15.1	15.9	15.2	15.4	13.8	13.5
39-061-0041	Hamilton	Winneste Ave.	15.7	15.5	15.0	15.2				
39-061-0042	Hamilton	W. 8th St	18.4	17.1	16.5	17.3	16.7	16.6	15.1	14.7
39-061-0043	Hamilton	Kemper Rd.	16.9	15.7	15.3	15.8	15.4	15.4	14.2	
39-061-7001	Hamilton	Sherman Ave.	16.7	16.3	15.8	16.6	16.0	15.9	14.4	13.9
39-061-8001	Hamilton	Murray Rd.	17.8	17.1	16.9	17.9	17.4	17.3	15.5	14.6
39-165-0007	Warren	Southeast St.								12.5

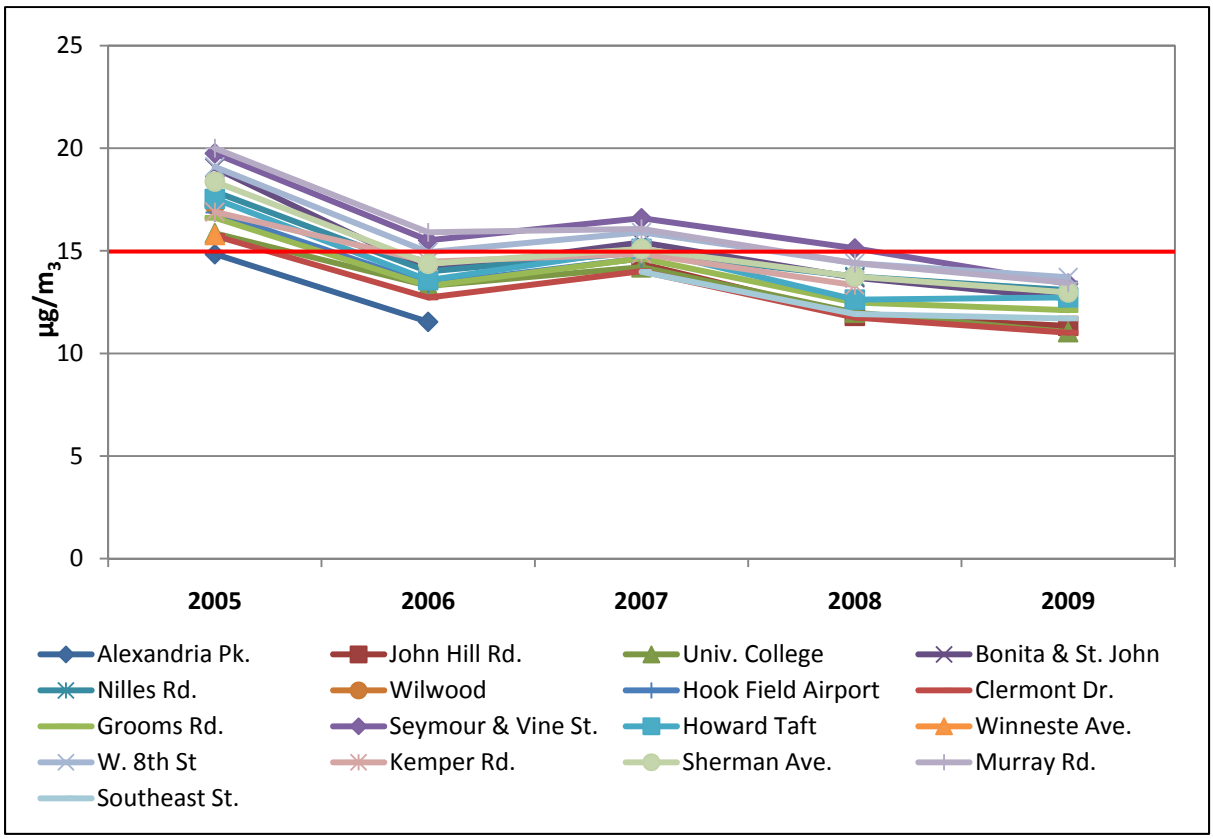
Value above the annual $PM_{2.5}$ standard.

Note: The Wilwood and Winneste Ave. monitors in Ohio were discontinued on December 31, 2005. The Alexandria Park monitor in Kentucky was discontinued on December 31, 2006. The Hook Field Airport monitor in Ohio was discontinued on December 31, 2007.

Design Values for the Cincinnati Area for Fine Particles, 2003 through 2009



Cincinnati Area Annual Fiine Particles Trends, 2005 through 2009



Note: The Wilwood and Winneste Ave. monitors in Ohio were discontinued on December 31, 2005. The Alexandria Park monitor in Kentucky was discontinued on December 31, 2006. The Hook Field Airport monitor in Ohio was discontinued on December 31, 2007.

APPENDIX B

Nitrogen Oxides (NO_x), Sulfur Dioxides (SO_2) and Direct Fine Particulate Matter ($PM_{2.5}$) Point Source Emissions (2005 and 2008) for the Cincinnati-Hamilton, OH-KY-IN Nonattainment Area

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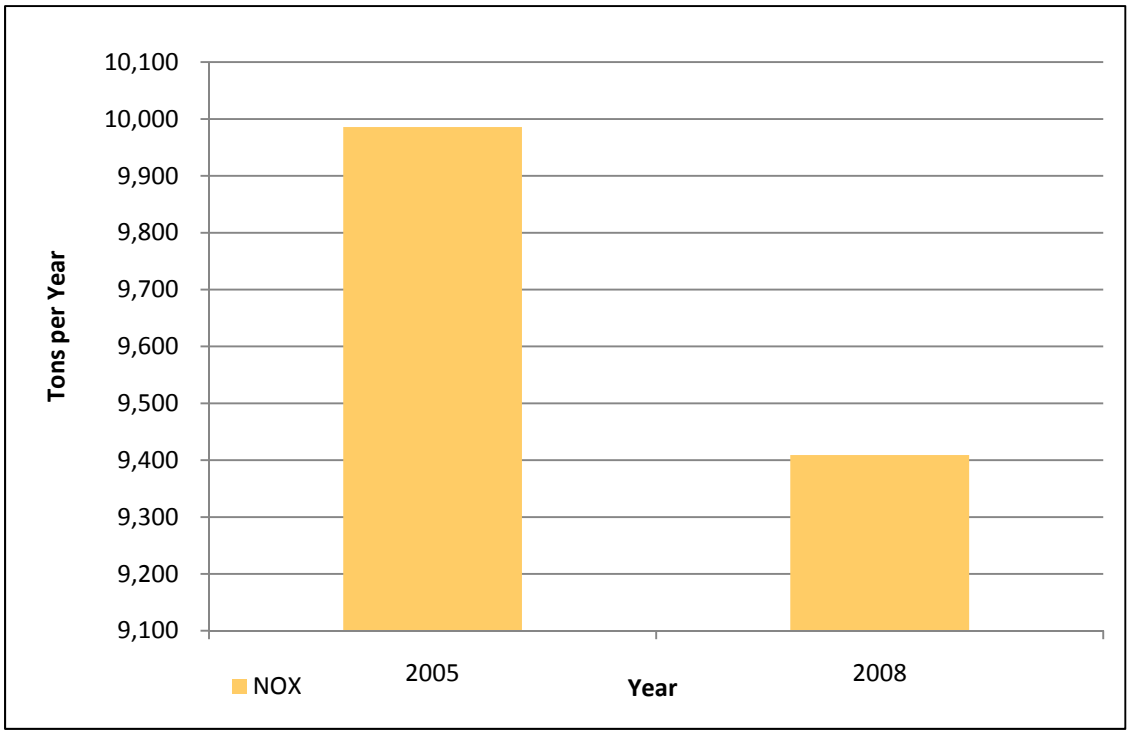
Dearborn County, IN Point Source Totals (Tons per Year)			
Year	**NO_x**	**SO_2**	**Direct $PM_{2.5}$**
2005	9,985.98	47,864.85	741.32
2008	9,409.03	27,063.43	866.20

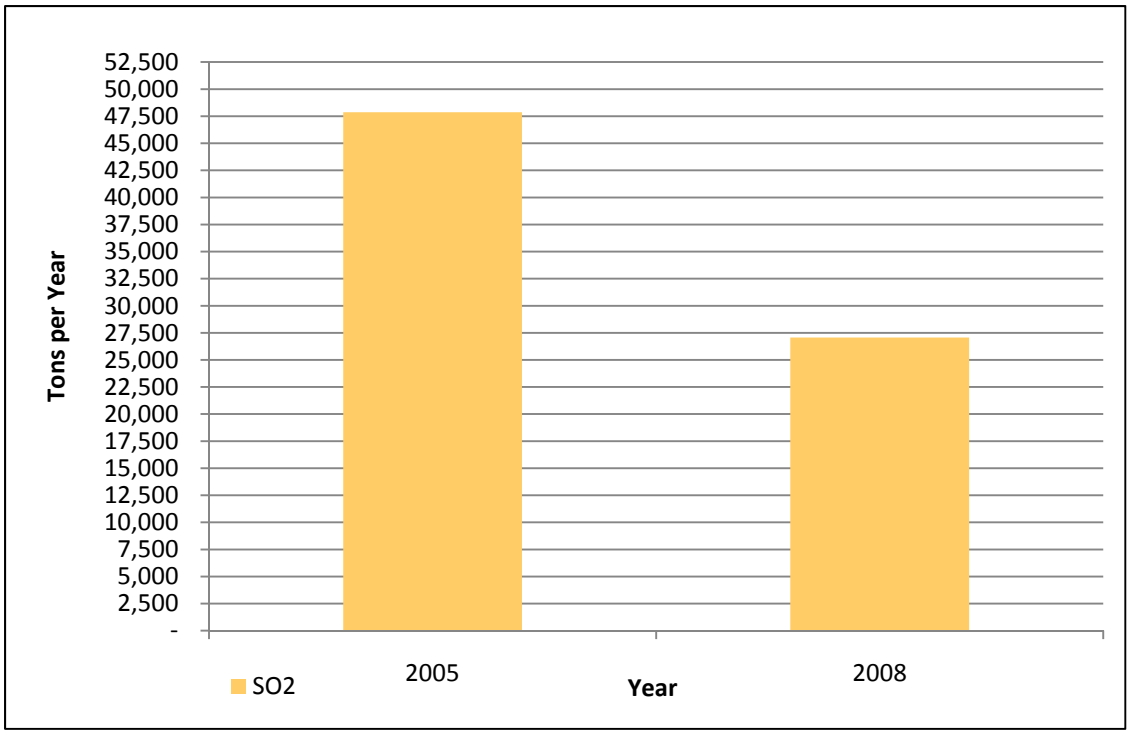
2005-Dearborn County, IN Point Source Emissions (Tons per Year)						
County	**EGU- NO_x**	**NON-EGU- NO_x**	**EGU-SO_2**	**NON-EGU- SO_2**	**EGU- Direct $PM_{2.5}$**	**NON-EGU- Direct $PM_{2.5}$**
Dearborn, IN	7,961.30	2,024.68	46,533.70	1,331.15	673.94	67.38
	NO_x		**SO_2**		**Direct $PM_{2.5}$**	
Grand Total	**9,985.98**		**47,864.85**		**741.32**	

2008-Dearborn County, IN Point Source Emissions (Tons per Year)						
County	**EGU- NO_x**	**NON-EGU- NO_x**	**EGU-SO_2**	**NON-EGU- SO_2**	**EGU- Direct $PM_{2.5}$**	**NON-EGU- Direct $PM_{2.5}$**
Dearborn, IN	7,429.20	1,979.83	25,729.10	1,334.33	804.18	62.02
	NO_x		**SO_2**		**Direct $PM_{2.5}$**	
Grand Total	**9,409.03**		**27,063.43**		**866.20**	

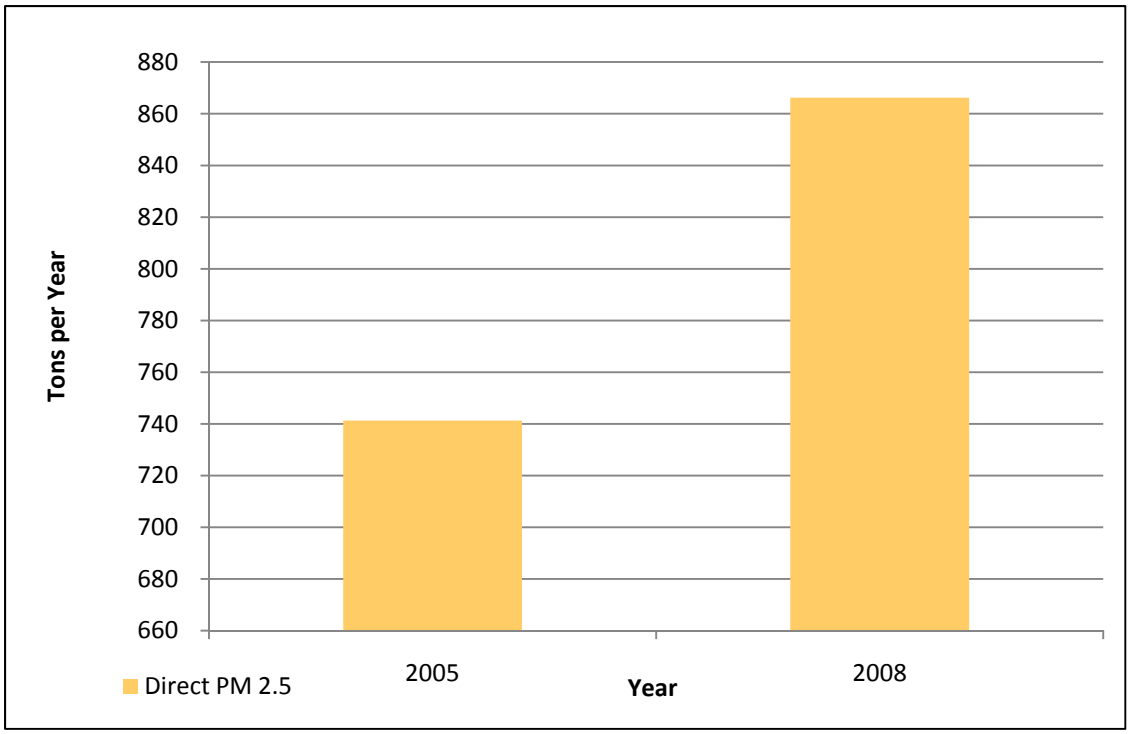
Dearborn County, IN NO_x Point Source Emission Trends, 2005 and 2008



Dearborn County, IN SO_2 Point Source Emission Trends, 2005 and 2008



Dearborn County, IN Direct $PM_{2.5}$ Point Source Emission Trends, 2005 and 2008

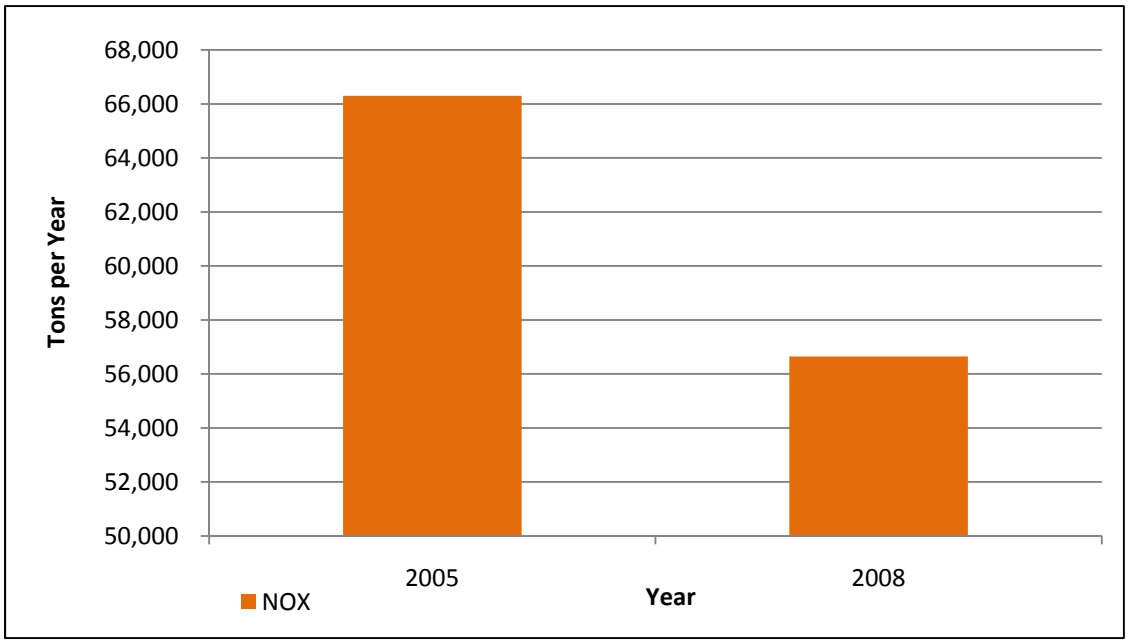


Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Point Source Totals (Tons per Year)			
Year	**NO_x**	**SO_2**	**Direct $PM_{2.5}$**
2005	66,302.14	233,927.65	3,415.69
2008	56,644.39	111,818.09	3,091.67

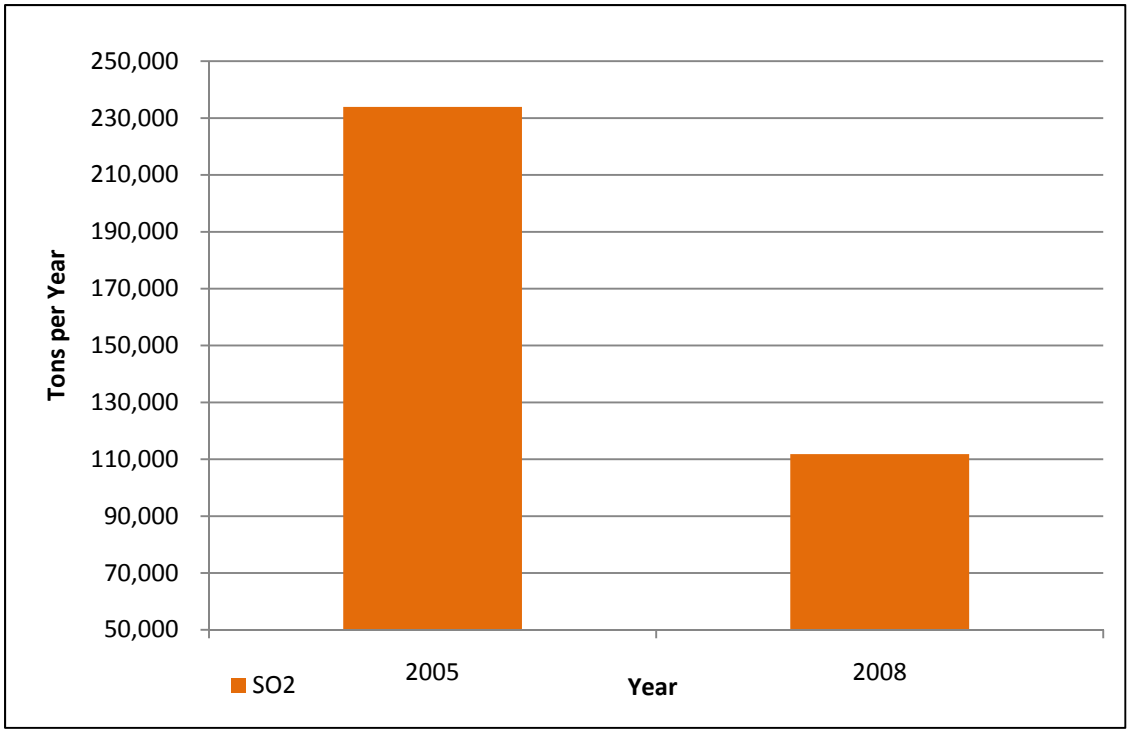
2005-Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Point Source Emissions (Tons per Year)						
County	**EGU NO_x**	**NON-EGU-NO_x**	**EGU SO_2**	**NON-EGU-SO_2**	**EGU-Direct $PM_{2.5}$**	**NON-EGU-Direct $PM_{2.5}$**
Dearborn County, IN	7,961.30	2,024.68	46,533.70	1,331.15	673.94	67.38
Boone County, KY	3,926.27	58.03	3,644.98	16.82	76.85	58.77
Campbell County, KY	0.00	53.68	0.00	0.97	0.00	84.25
Kenton County, KY	0.00	19.50	0.00	12.91	0.00	9.53
Butler County, OH	743.27	4,367.15	1,959.10	6,185.26	15.27	944.29
Clermont County, OH	28,063.56	67.50	88,876.65	162.19	648.21	7.93
Hamilton County, OH	15,236.04	2,756.21	77,381.13	7,819.40	648.64	161.88
Warren County, OH	0.00	1,024.95	0.00	3.39	0.00	18.75
	NO_x		**SO_2**		**Direct $PM_{2.5}$**	
Grand Total	**66,302.14**		**233,927.65**		**3,415.69**	

2008-Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Point Source Emissions (Tons per Year)						
County	**EGU NO_x**	**NON-EGU-NO_x**	**EGU SO_2**	**NON-EGU-SO_2**	**EGU-Direct $PM_{2.5}$**	**NON-EGU-Direct $PM_{2.5}$**
Dearborn County, IN	7,429.20	1,979.83	25,729.10	1,334.33	804.18	62.02
Boone County, KY	1,962.59	61.66	2,812.16	17.97	76.70	68.81
Campbell County, KY	0.00	49.52	0.00	0.96	0.00	89.52
Kenton County, KY	0.00	20.44	0.00	13.89	0.00	11.11
Butler County, OH	856.92	3,940.28	2,181.63	5,442.54	16.78	1,045.15
Clermont County, OH	24,233.18	42.71	42,918.28	118.05	532.61	3.86
Hamilton County, OH	12,372.00	2,652.79	24,693.00	6,552.65	202.88	158.14
Warren County, OH	0.00	1,043.27	0.00	3.53	0.00	19.91
	NO_x		**SO_2**		**Direct $PM_{2.5}$**	
Grand Total	**56,644.39**		**111,818.09**		**3,091.67**	

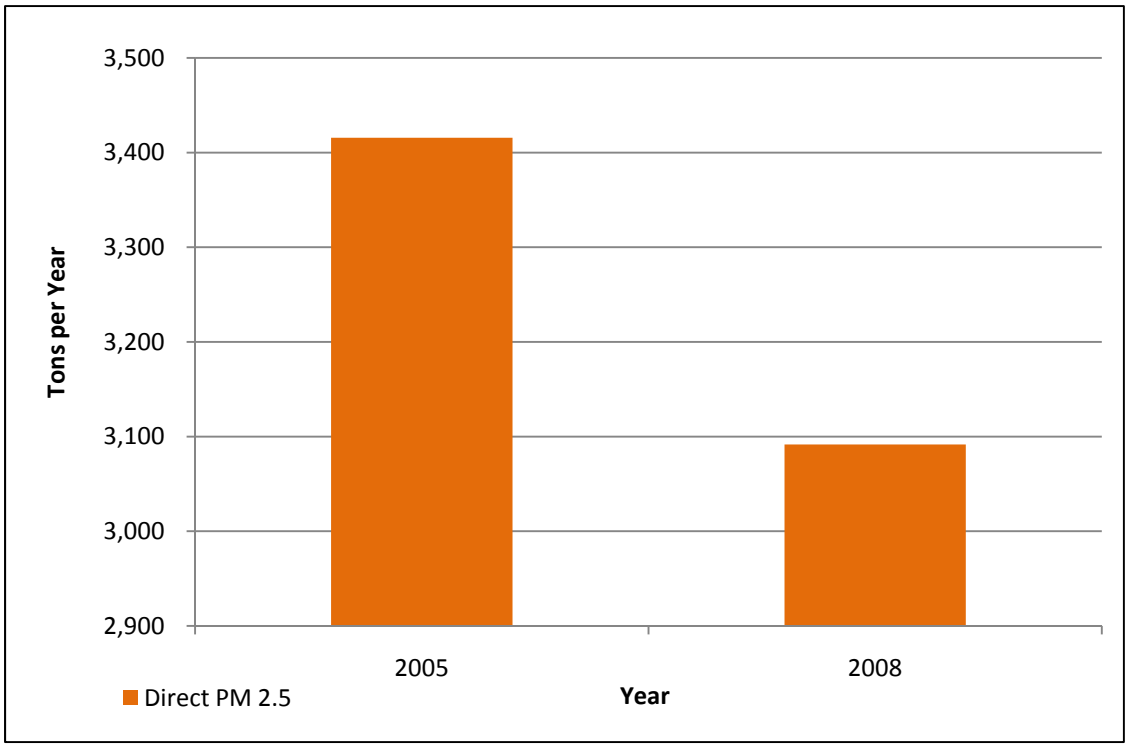
Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area NO_x Point Source Emission Trends, 2005 and 2008



Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area SO_2 Point Source Emission Trends, 2005 and 2008



Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Direct $PM_{2.5}$ Point Source Emission Trends, 2005 and 2008



APPENDIX C

Nitrogen Oxides (NO_x), Sulfur Dioxides (SO_2) and Direct Fine Particulate Matter ($PM_{2.5}$) (2005 and 2008) Emission Trends, All Sources, Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area

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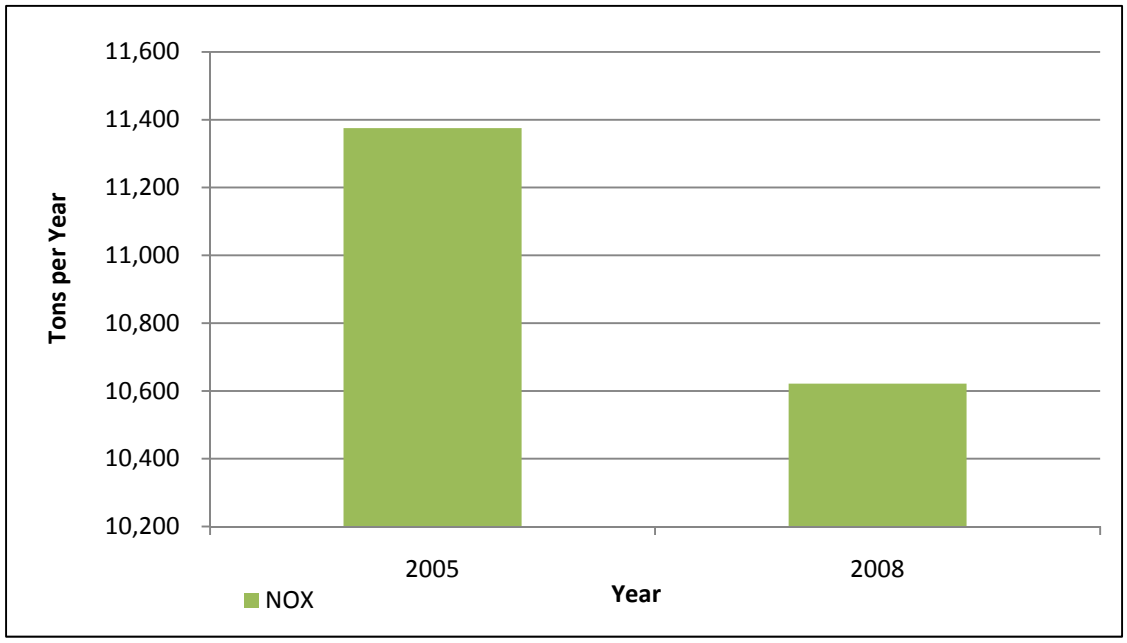
2005-Dearborn County, IN				
COUNTY, STATE	**Sector**	**NO_X**	**Direct $PM_{2.5}$**	**SO_2**
DEARBORN COUNTY, IN	ONROAD	865.46	33.98	2.45
DEARBORN COUNTY, IN	NONROAD	382.53	23.96	40.16
DEARBORN COUNTY, IN	AREA	141.37	4.29	78.72
DEARBORN COUNTY, IN	POINT	9,985.98	741.32	47,864.85

	2005 Dearborn County, IN Totals				
	ONROAD	**NONROAD**	**AREA**	**POINT**	**GRAND TOTAL**
NO_X	865.46	382.53	141.37	9,985.98	**11,375.34**
Direct $PM_{2.5}$	33.98	23.96	4.29	741.32	**803.55**
SO_2	2.45	40.16	78.72	47,864.85	**47,986.18**

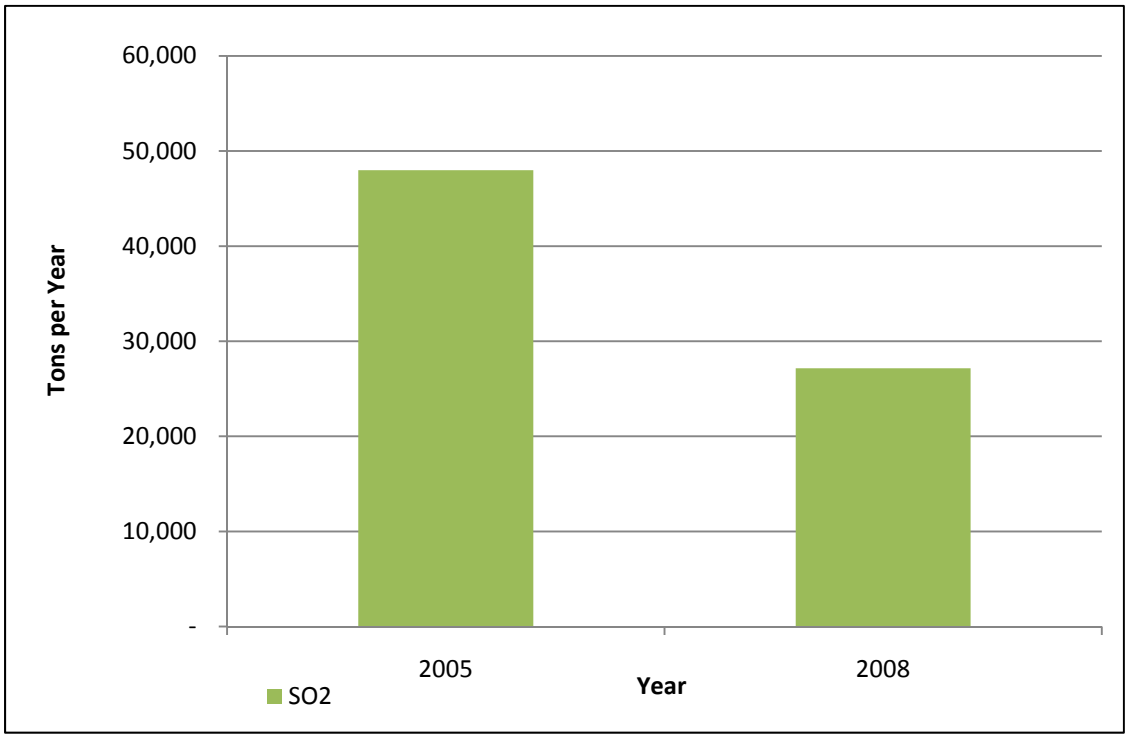
2008-Dearborn County, IN				
COUNTY, STATE	**Sector**	**NO_X**	**Direct $PM_{2.5}$**	**SO_2**
DEARBORN COUNTY, IN	ONROAD	748.81	29.89	2.69
DEARBORN COUNTY, IN	NONROAD	318.09	19.91	17.38
DEARBORN COUNTY, IN	AREA	145.42	4.29	81.02
DEARBORN COUNTY, IN	POINT	9,409.03	866.20	27,063.43

	2008 Dearborn County, IN Totals				
	ONROAD	**NONROAD**	**AREA**	**POINT**	**GRAND TOTAL**
NO_X	748.81	318.09	145.42	9,409.03	**10,621.35**
Direct $PM_{2.5}$	29.89	19.91	4.29	866.20	**920.29**
SO_2	2.69	17.38	81.02	27,063.43	**27,164.52**

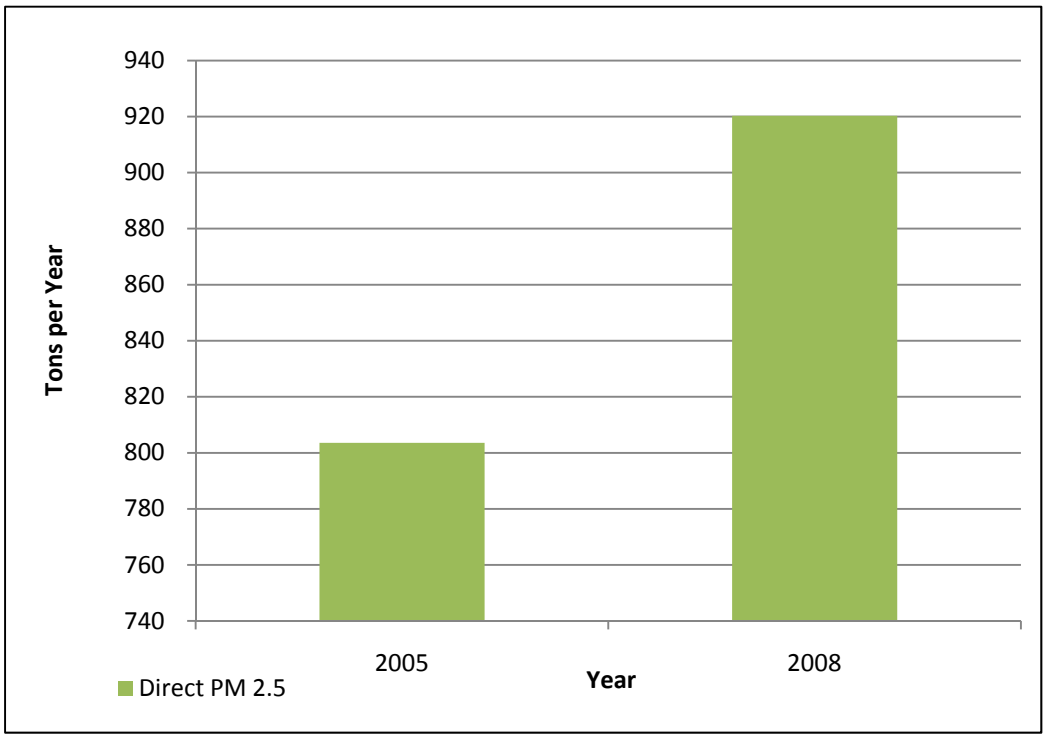
NO_x Emission Trends, All Sources in Dearborn County, IN, 2005 and 2008-With CAIR



SO_2 Emission Trends, All Sources in Dearborn County, IN, 2005 and 2008-With CAIR



Direct $PM_{2.5}$ Emission Trends, All Sources in Dearborn County, IN, 2005 and 2008-With CAIR



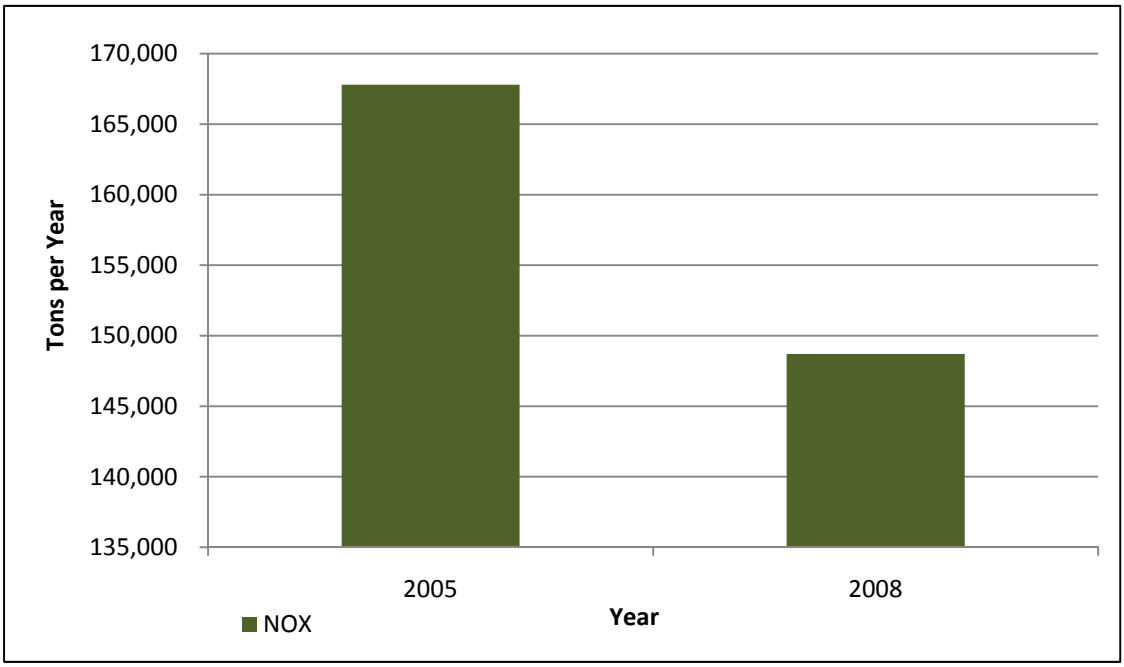
2005-Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area				
COUNTY, STATE	**Sector**	**NO_X**	**Direct $PM_{2.5}$**	**SO_2**
DEARBORN COUNTY, IN	ONROAD	865.46	33.98	2.45
DEARBORN COUNTY, IN	NONROAD	382.53	23.96	40.16
DEARBORN COUNTY, IN	AREA	141.37	4.29	78.72
DEARBORN COUNTY, IN	POINT	9,985.98	741.32	47,864.85
BOONE COUNTY, KY	ONROAD	5,126.88	205.21	15.91
BOONE COUNTY, KY	NONROAD	3,858.96	304.76	494.27
BOONE COUNTY, KY	AREA	1,844.50	351.27	1,054.33
BOONE COUNTY, KY	POINT	3,984.30	135.62	3,661.80
CAMPBELL COUNTY, KY	ONROAD	3,041.21	120.30	9.30
CAMPBELL COUNTY, KY	NONROAD	1,902.55	80.95	239.99
CAMPBELL COUNTY, KY	AREA	523.45	200.08	471.77
CAMPBELL COUNTY, KY	POINT	53.68	84.25	0.97
KENTON COUNTY, KY	ONROAD	5,328.44	212.29	16.24
KENTON COUNTY, KY	NONROAD	2,684.68	119.08	248.34
KENTON COUNTY, KY	AREA	1,542.27	365.74	1,196.61
KENTON COUNTY, KY	POINT	19.50	9.53	12.91
BUTLER COUNTY, OH	ONROAD	10,910.37	413.97	30.01
BUTLER COUNTY, OH	NONROAD	3,268.33	216.47	341.20
BUTLER COUNTY, OH	AREA	796.34	173.24	224.54
BUTLER COUNTY, OH	POINT	5,110.42	959.56	8,144.36
CLERMONT COUNTY, OH	ONROAD	7,295.87	281.79	20.51
CLERMONT COUNTY, OH	NONROAD	1,477.30	110.65	161.66
CLERMONT COUNTY, OH	AREA	612.97	193.70	164.72
CLERMONT COUNTY, OH	POINT	28,131.06	656.14	89,038.84
HAMILTON COUNTY, OH	ONROAD	31,127.09	1,222.02	88.85
HAMILTON COUNTY, OH	NONROAD	6,309.86	398.01	592.45
HAMILTON COUNTY, OH	AREA	1,923.27	303.61	163.45
HAMILTON COUNTY, OH	POINT	17,992.25	810.52	85,200.53
WARREN COUNTY, OH	ONROAD	8,224.57	320.74	23.54
WARREN COUNTY, OH	NONROAD	1,886.04	146.67	31.67
WARREN COUNTY, OH	AREA	426.57	236.92	140.25
WARREN COUNTY, OH	POINT	1,024.95	18.75	3.39

	2005 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Totals				
	ONROAD	**NONROAD**	**AREA**	**POINT**	**GRAND TOTAL**
NO_X	71,919.89	21,770.25	7,810.74	66,302.14	**167,803.02**
Direct $PM_{2.5}$	2,810.30	1,400.55	1,828.85	3,415.69	**9,455.39**
SO_2	206.81	2,149.74	3,494.39	233,927.65	**239,778.59**

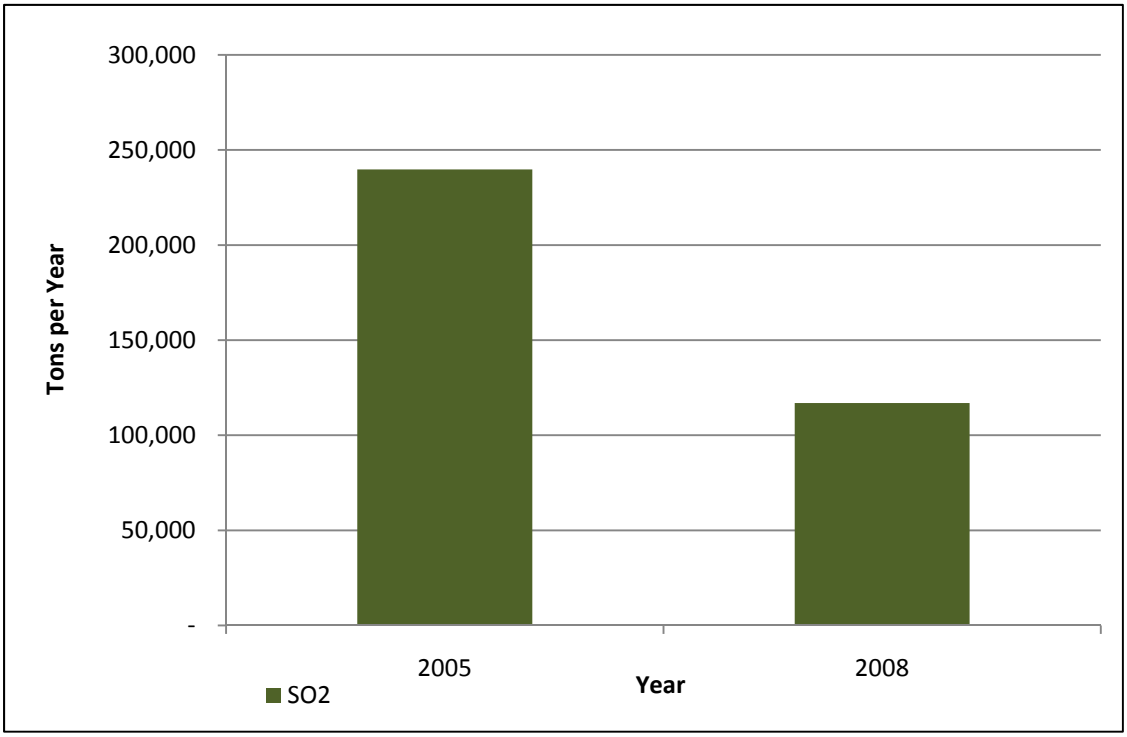
2008-Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area				
COUNTY, STATE	**Sector**	**NO_X**	**Direct $PM_{2.5}$**	**SO_2**
DEARBORN COUNTY, IN	ONROAD	748.81	29.89	2.69
DEARBORN COUNTY, IN	NONROAD	318.09	19.91	17.38
DEARBORN COUNTY, IN	AREA	145.42	4.29	81.02
DEARBORN COUNTY, IN	POINT	9,409.03	866.20	27,063.43
BOONE COUNTY, KY	ONROAD	5,067.94	251.85	16.71
BOONE COUNTY, KY	NONROAD	3,772.42	310.52	435.93
BOONE COUNTY, KY	AREA	1,897.28	353.71	1,066.79
BOONE COUNTY, KY	POINT	2,024.25	145.51	2,830.13
CAMPBELL COUNTY, KY	ONROAD	2,988.33	146.46	9.69
CAMPBELL COUNTY, KY	NONROAD	1,833.46	76.09	206.21
CAMPBELL COUNTY, KY	AREA	536.71	201.26	479.14
CAMPBELL COUNTY, KY	POINT	49.52	89.52	0.96
KENTON COUNTY, KY	ONROAD	5,057.93	29.89	16.34
KENTON COUNTY, KY	NONROAD	2,562.60	110.61	190.40
KENTON COUNTY, KY	AREA	1,581.60	366.69	1,210.42
KENTON COUNTY, KY	POINT	20.44	11.11	13.89
BUTLER COUNTY, OH	ONROAD	9,803.70	377.64	34.25
BUTLER COUNTY, OH	NONROAD	2,833.89	185.81	174.34
BUTLER COUNTY, OH	AREA	807.64	180.43	221.09
BUTLER COUNTY, OH	POINT	4,797.20	1,061.93	7,624.17
CLERMONT COUNTY, OH	ONROAD	6,516.40	256.60	23.32
CLERMONT COUNTY, OH	NONROAD	1,284.92	95.48	66.25
CLERMONT COUNTY, OH	AREA	619.27	196.15	162.20
CLERMONT COUNTY, OH	POINT	24,275.89	536.47	43,036.33
HAMILTON COUNTY, OH	ONROAD	27,020.93	1,080.54	98.30
HAMILTON COUNTY, OH	NONROAD	5,402.04	345.12	274.62
HAMILTON COUNTY, OH	AREA	1,955.47	323.94	161.80
HAMILTON COUNTY, OH	POINT	15,024.79	361.02	31,245.65
WARREN COUNTY, OH	ONROAD	7,267.18	289.56	26.57
WARREN COUNTY, OH	NONROAD	1,607.45	124.78	34.56
WARREN COUNTY, OH	AREA	432.28	238.33	138.31
WARREN COUNTY, OH	POINT	1,043.27	19.91	3.53

	2008 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Totals				
	ONROAD	**NONROAD**	**AREA**	**POINT**	**GRAND TOTAL**
NO_X	64,471.22	19,614.87	7,975.67	56,644.39	**148,706.15**
Direct $PM_{2.5}$	2,462.43	1,268.32	1,864.80	3,091.67	**8,687.22**
SO_2	227.87	1,399.69	3,520.77	111,818.09	**116,966.42**

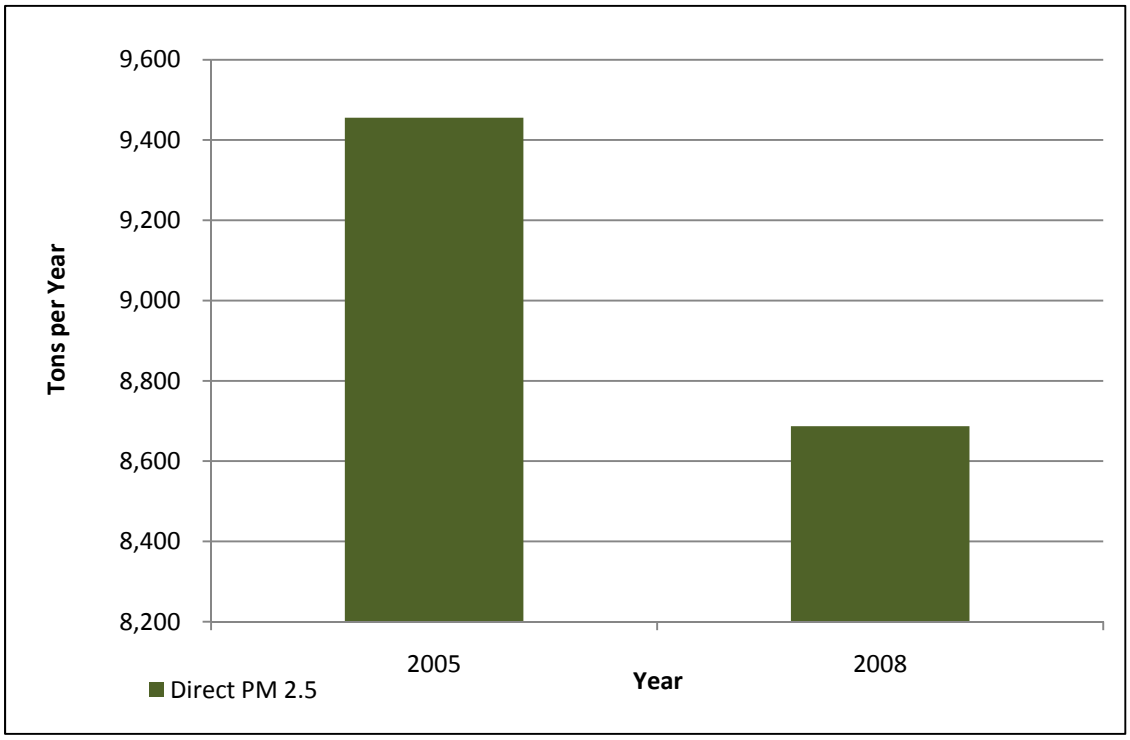
NO_x Emission Trends, All Sources in Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area, 2005 and 2008-With CAIR



SO_2 Emission Trends, All Sources in Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area, 2005 and 2008-With CAIR



Direct $PM_{2.5}$ Emission Trends, All Sources in Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area, 2005 and 2008-IN/KY-With CAIR, OH-Without CAIR



APPENDIX D

Nitrogen Oxides (NO_x) and Sulfur Dioxide (SO_2) Emissions from Electric Generating Units, Lawrenceburg Township, Dearborn County, Indiana and Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area

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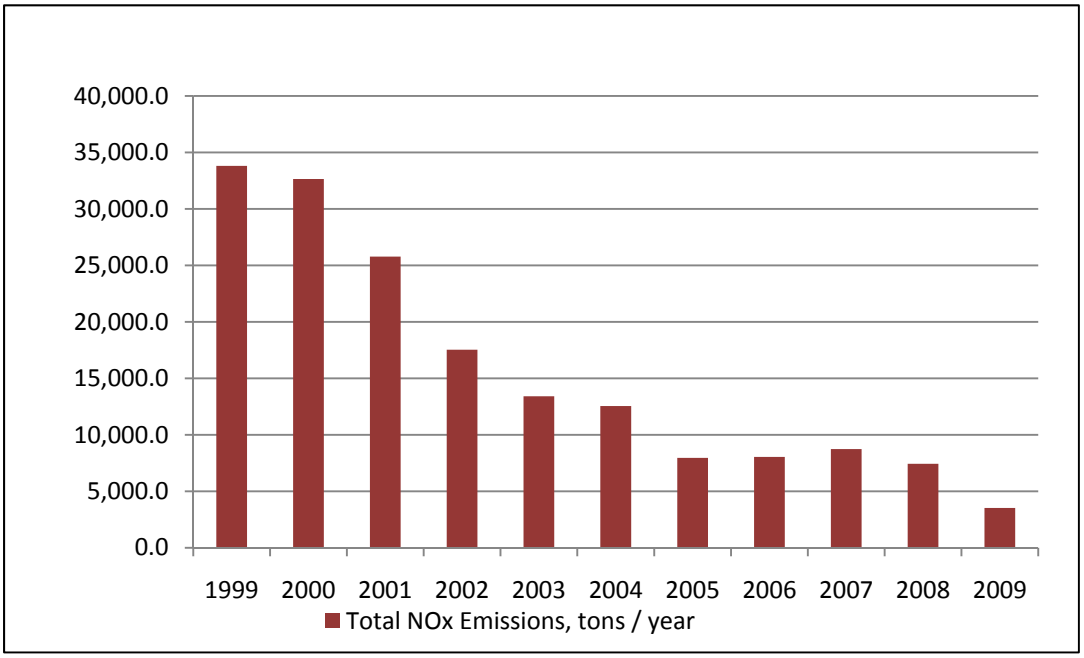
Lawrenceburg Township, Dearborn County, Indiana NO_x Emissions from EGUs

Year	Total NO_x Emissions, tons/year
1999	33,807.1
2000	32,657.1
2001	25,774.7
2002	17,533.8
2003	13,416.7
2004	12,552.8
2005	7,961.3
2006	8,041.6
2007	8,739.2
2008	7,429.2
2009	3,529.3

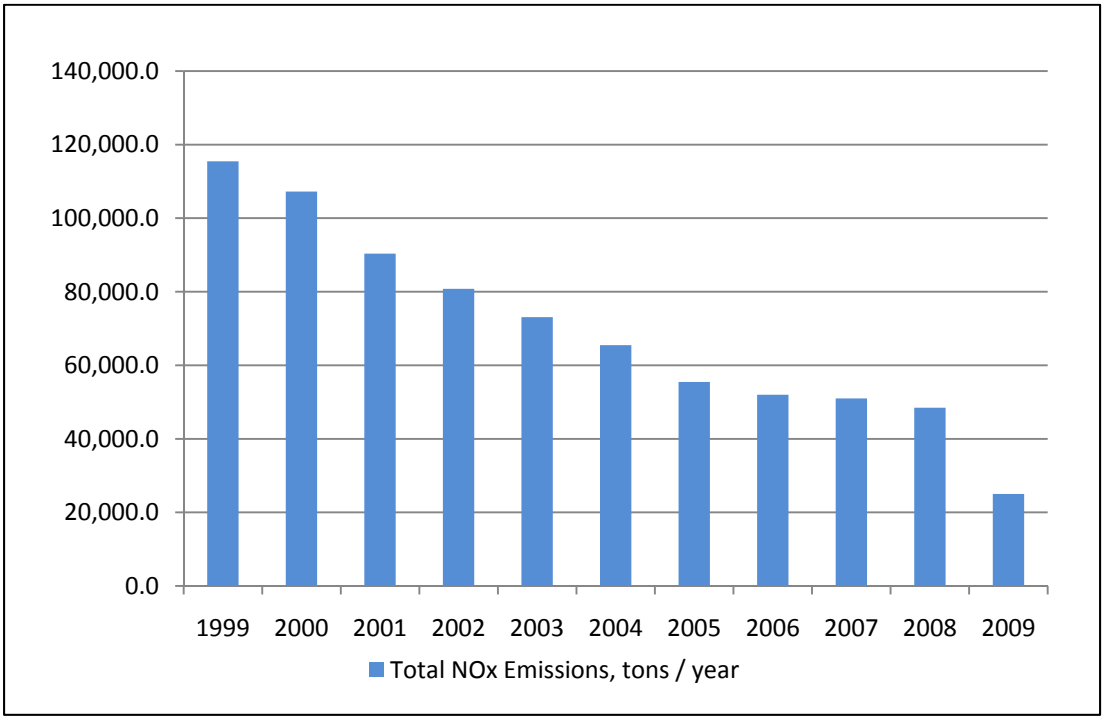
Lawrenceburg Township, Dearborn County, Indiana NO_x Emissions from EGUs



Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs

Year	Total NO_x Emissions, tons/year
1999	115,477.8
2000	107,227.9
2001	90,347.2
2002	80,808.6
2003	73,084.4
2004	65,491.6
2005	55,492.4
2006	52,004.5
2007	50,979.6
2008	48,464.0
2009	24,997.8

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs



Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 1999

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	33,807.1
Kentucky	East Bend	10,113.8
Ohio	Miami Fort Generating Station	26,429.1
Ohio	William H Zimmer Generating Station	22,792.3
Ohio	Walter C Beckjord Generating Station	22,091.4
Ohio	Woodsdale	244.1
	Total	**115,477.8**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2000

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	32,657.1
Kentucky	East Bend	8,671.0
Ohio	Madison Generating Station	15.1
Ohio	Miami Fort Generating Station	25,518.8
Ohio	William H Zimmer Generating Station	18,682.3
Ohio	Walter C Beckjord Generating Station	21,408.7
Ohio	Woodsdale	274.9
	Total	**107,227.9**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2001

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	25,774.7
Kentucky	East Bend	8,161.5
Ohio	Madison Generating Station	32.0
Ohio	Miami Fort Generating Station	18,598.8
Ohio	William H Zimmer Generating Station	20,886.3
Ohio	Walter C Beckjord Generating Station	16,743.0
Ohio	Woodsdale	150.9
	Total	**90,347.2**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2002

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	17,533.8
Kentucky	East Bend	5,454.9
Ohio	Madison Generating Station	48.7
Ohio	Miami Fort Generating Station	17,941.5
Ohio	William H Zimmer Generating Station	20,965.6
Ohio	Walter C Beckjord Generating Station	18,736.8
Ohio	Woodsdale	127.3
	Total	**80,808.6**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2003

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	13,416.7
Kentucky	East Bend	7,056.0
Ohio	Madison Generating Station	51.7
Ohio	Miami Fort Generating Station	15,593.7
Ohio	William H Zimmer Generating Station	20,174.0
Ohio	Walter C Beckjord Generating Station	16,727.9
Ohio	Woodsdale	64.4
	Total	**73,084.4**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2004

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	12,552.8
Kentucky	East Bend	6,187.2
Ohio	Madison Generating Station	14.0
Ohio	Miami Fort Generating Station	17,102.2
Ohio	William H Zimmer Generating Station	14,692.7
Ohio	Walter C Beckjord Generating Station	14.914.2
Ohio	Woodsdale	28.5
	Total	**65,491.6**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2005

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	7,961.3
Kentucky	East Bend	3,952.2
Ohio	Madison Generating Station	91.5
Ohio	Miami Fort Generating Station	15,264.6
Ohio	William H Zimmer Generating Station	15,153.0
Ohio	Walter C Beckjord Generating Station	13,012.8
Ohio	Woodsdale	57.0
	Total	**55,492.4**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2006

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	8,041.6
Kentucky	East Bend	5,399.7
Ohio	Madison Generating Station	38.4
Ohio	Miami Fort Generating Station	12,797.9
Ohio	William H Zimmer Generating Station	13,851.3
Ohio	Walter C Beckjord Generating Station	11,830.2
Ohio	Woodsdale	45.4
	Total	**52,004.5**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2007

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	8,739.2
Kentucky	East Bend	5,563.0
Ohio	Madison Generating Station	44.3
Ohio	Miami Fort Generating Station	9,754.6
Ohio	William H Zimmer Generating Station	13,736.6
Ohio	Walter C Beckjord Generating Station	13,031.8
Ohio	Woodsdale	110.1
	Total	**50,979.6**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2008

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	7,429.2
Kentucky	East Bend	4,492.4
Ohio	Madison Generating Station	16.1
Ohio	Miami Fort Generating Station	12,371.7
Ohio	William H Zimmer Generating Station	16,531.1
Ohio	Walter C Beckjord Generating Station	7,549.0
Ohio	Woodsdale	74.5
	Total	**48,464.0**

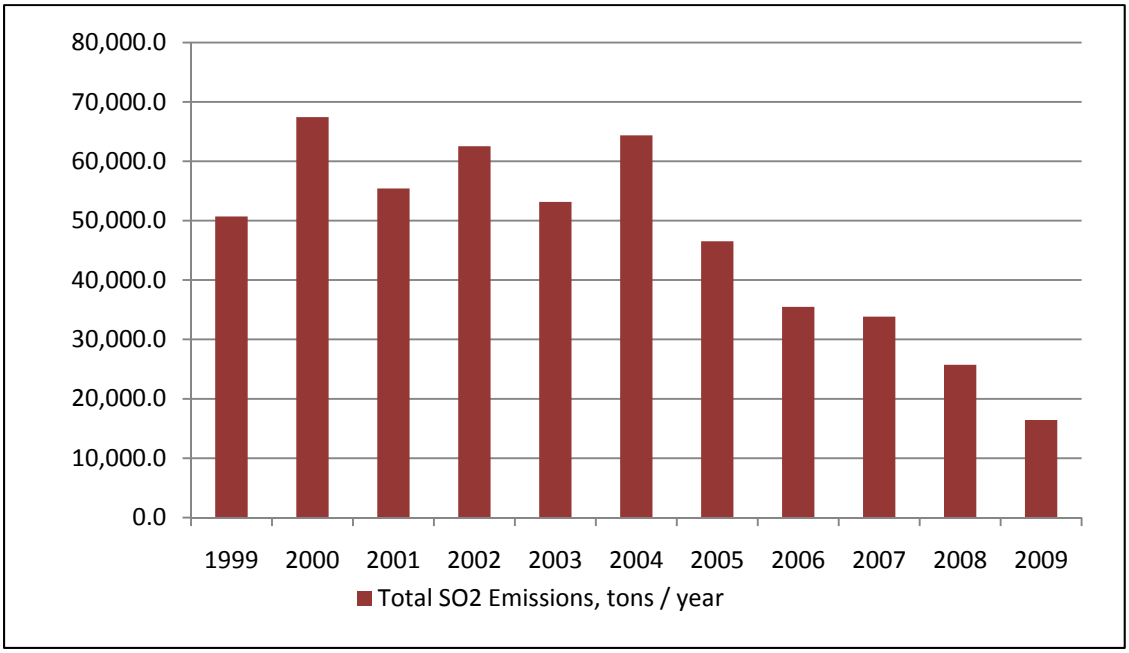
Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area NO_x Emissions from EGUs, 2009

State	Facility	NO_x Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	3,529.3
Kentucky	East Bend	2,436.2
Ohio	Madison Generating Station	25.6
Ohio	Miami Fort Generating Station	4,337.8
Ohio	William H Zimmer Generating Station	3,646.4
Ohio	Walter C Beckjord Generating Station	10,948.2
Ohio	Woodsdale	74.3
	Total	**24,997.8**

Lawrenceburg Township, Dearborn County, Indiana SO_2 Emissions from EGUs

Year	Total SO_2 Emissions, tons/year
1999	50,715.7
2000	67,446.1
2001	55,430.6
2002	62,531.7
2003	53,175.0
2004	64,387.3
2005	46,533.7
2006	35,494.2
2007	33,828.9
2008	25,729.1
2009	16,442.3

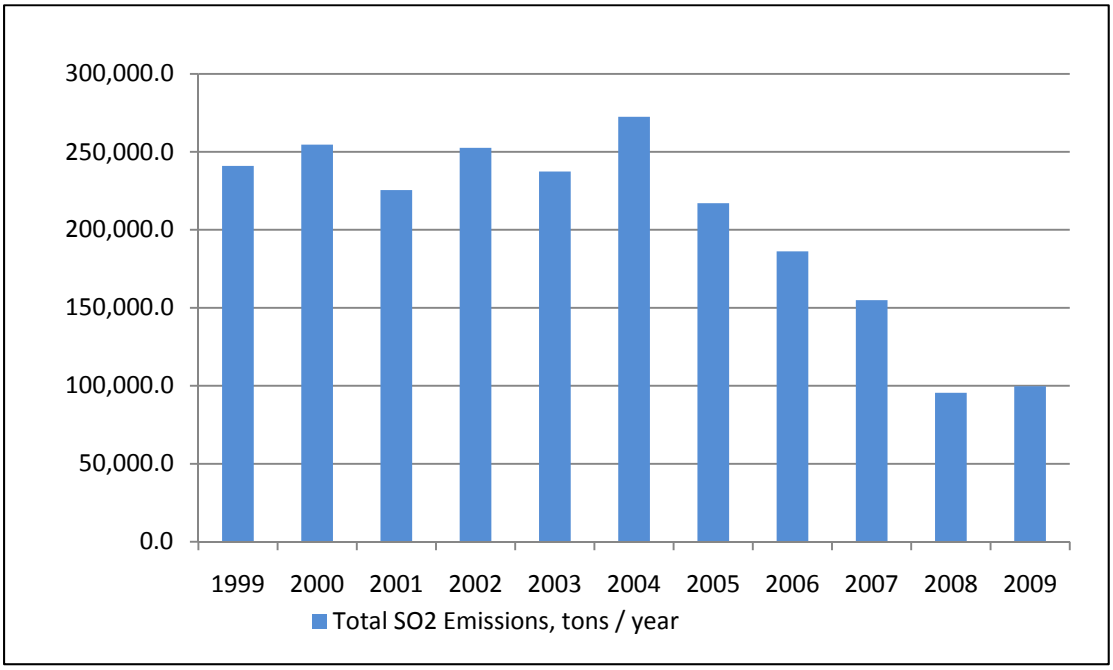
Lawrenceburg Township, Dearborn County, Indiana SO_2 Emissions from EGUs



Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs

Year	Total SO_2 Emissions, tons/year
1999	240,983.6
2000	254,655.4
2001	225,526.3
2002	252,572.9
2003	237,439.2
2004	272,465.6
2005	217,111.1
2006	186,150.3
2007	154,905.1
2008	95,498.4
2009	99,757.0

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs



Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 1999

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	50,715.7
Kentucky	East Bend	18,095.8
Ohio	Miami Fort Generating Station	78,086.2
Ohio	William H Zimmer Generating Station	25,482.4
Ohio	Walter C Beckjord Generating Station	68,601.7
Ohio	Woodsdale	1.8
	Total	**240,983.6**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2000

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	67,446.1
Kentucky	East Bend	14,850.4
Ohio	Madison Generating Station	0.2
Ohio	Miami Fort Generating Station	81,512.4
Ohio	William H Zimmer Generating Station	19,410.6
Ohio	Walter C Beckjord Generating Station	71,433.5
Ohio	Woodsdale	2.2
	Total	**254,655.4**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2001

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	55,430.6
Kentucky	East Bend	13,106.5
Ohio	Madison Generating Station	0.6
Ohio	Miami Fort Generating Station	73,538.9
Ohio	William H Zimmer Generating Station	21,651.5
Ohio	Walter C Beckjord Generating Station	61,797.4
Ohio	Woodsdale	0.8
	Total	**225,526.3**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2002

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	62,531.7
Kentucky	East Bend	12,918.1
Ohio	Madison Generating Station	0.7
Ohio	Miami Fort Generating Station	85,699.4
Ohio	William H Zimmer Generating Station	21,491.8
Ohio	Walter C Beckjord Generating Station	69,930.6
Ohio	Woodsdale	0.6
	Total	**252,572.9**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2003

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	53,175.0
Kentucky	East Bend	14,959.8
Ohio	Madison Generating Station	0.2
Ohio	Miami Fort Generating Station	81,514.6
Ohio	William H Zimmer Generating Station	22,917.9
Ohio	Walter C Beckjord Generating Station	64,871.3
Ohio	Woodsdale	0.4
	Total	**237,439.2**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2004

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	64,387.3
Kentucky	East Bend	11,545.5
Ohio	Madison Generating Station	0.2
Ohio	Miami Fort Generating Station	100,576.7
Ohio	William H Zimmer Generating Station	21,638.3
Ohio	Walter C Beckjord Generating Station	74,317.5
Ohio	Woodsdale	0.1
	Total	**272,465.6**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2005

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	46,533.7
Kentucky	East Bend	3,666.7
Ohio	Madison Generating Station	1.6
Ohio	Miami Fort Generating Station	77,583.2
Ohio	William H Zimmer Generating Station	22,379.5
Ohio	Walter C Beckjord Generating Station	66,946.1
Ohio	Woodsdale	0.3
	Total	**217,111.1**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2006

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	35,494.2
Kentucky	East Bend	3,946.5
Ohio	Madison Generating Station	0.7
Ohio	Miami Fort Generating Station	62,028.0
Ohio	William H Zimmer Generating Station	22,054.1
Ohio	Walter C Beckjord Generating Station	62,626.6
Ohio	Woodsdale	0.2
	Total	**186,150.3**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2007

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	33,828.9
Kentucky	East Bend	2,451.8
Ohio	Madison Generating Station	0.8
Ohio	Miami Fort Generating Station	46,938.9
Ohio	William H Zimmer Generating Station	16,776.4
Ohio	Walter C Beckjord Generating Station	54,907.7
Ohio	Woodsdale	0.6
	Total	**154,905.1**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2008

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	25,729.1
Kentucky	East Bend	2,713.4
Ohio	Madison Generating Station	0.2
Ohio	Miami Fort Generating Station	24,693.2
Ohio	William H Zimmer Generating Station	15,961.6
Ohio	Walter C Beckjord Generating Station	26,400.5
Ohio	Woodsdale	0.4
	Total	**95,498.4**

Entire Cincinnati-Hamilton OH-KY-IN Nonattainment Area SO_2 Emissions from EGUs, 2009

State	Facility	SO_2 Emissions, tons/year
Indiana	American Electric Power (AEP)-Tanners Creek Generating Station	16,442.3
Kentucky	East Bend	1,724.6
Ohio	Madison Generating Station	0.4
Ohio	Miami Fort Generating Station	25,339.9
Ohio	William H Zimmer Generating Station	14,284.9
Ohio	Walter C Beckjord Generating Station	41,964.5
Ohio	Woodsdale	0.4
	Total	**99,757.0**

APPENDIX E

2008 Base Year Emissions Inventory and 2015 and 2021 Projected Emissions Inventory for Nitrogen Oxides (NO_x), Sulfur Dioxides (SO_2) and Direct Fine Particulate Matter ($PM_{2.5}$) in Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area

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2008 Lawrenceburg Township, Dearborn County, IN (Tons Per Year)

$PM_{2.5}$		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	29.89	19.91	4.29	804.18	62.02	**920.29**

SO_2		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	2.69	17.38	81.02	25,729.10	1,334.33	**27,164.52**

NO_x		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	748.81	318.09	145.42	7,429.20	1,979.83	**10,621.35**

2015 Lawrenceburg Township, Dearborn County, IN (Tons Per Year)

$PM_{2.5}$		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	25.14	13.34	4.11	847.16	60.00	**949.75**

SO_2		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	2.87	4.73	77.64	39,295.70	1,335.94	**40,716.88**

NO_x		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	482.33	219.83	143.39	9,862.76	1,965.19	**12,673.50**

2021 Lawrenceburg Township, Dearborn County, IN (Tons Per Year)

$PM_{2.5}$		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	18.11	9.07	3.98	922.81	57.32	**1,011.29**

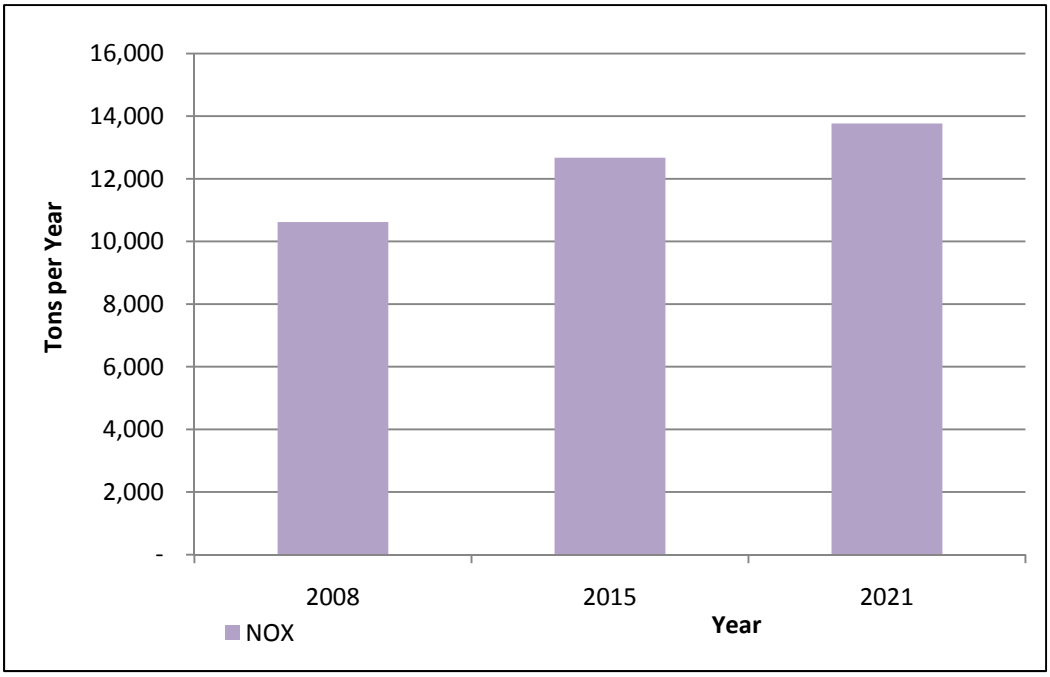
SO_2		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	3.19	1.14	75.69	36,843.66	1,337.95	**38,261.63**

NO_x		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
	DEARBORN COUNTY, IN	297.95	154.18	142.90	11,229.31	1,943.22	**13,767.56**

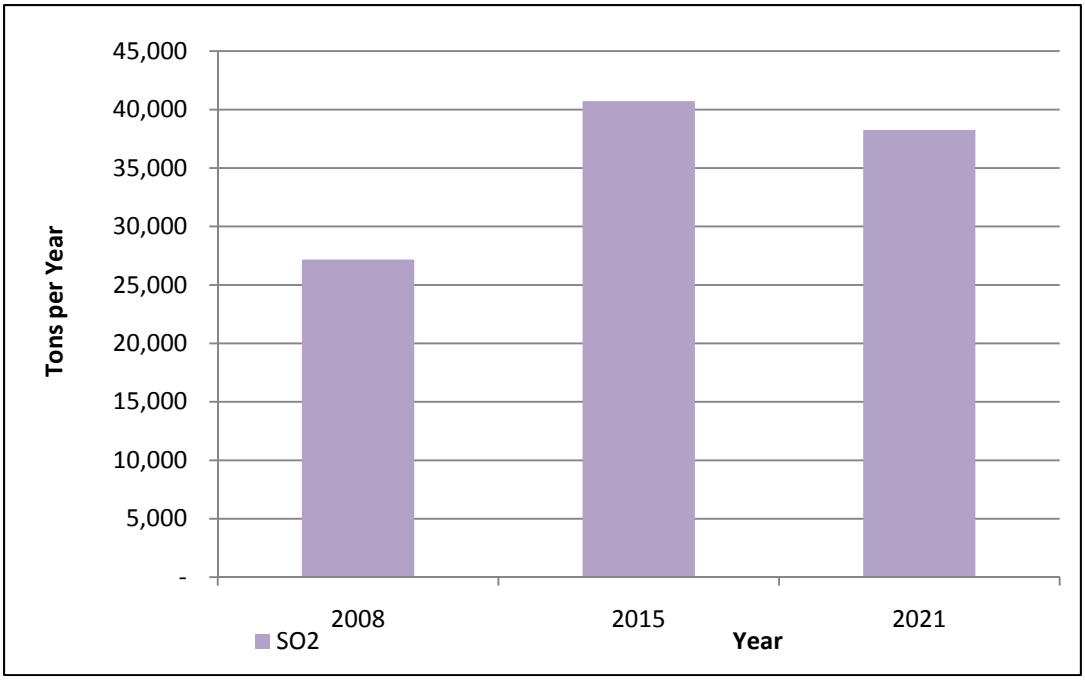
Lawrenceburg Township, Dearborn County, IN Percent Change (Tons Per Year)

	2008	2021	Change	% Change
NO_x	10,621.35	13,767.56	3,146.21	29.6%
SO_2	27,164.52	38,261.63	11,097.11	40.8%
Direct $PM_{2.5}$	920.29	1,011.29	91.00	9.8%

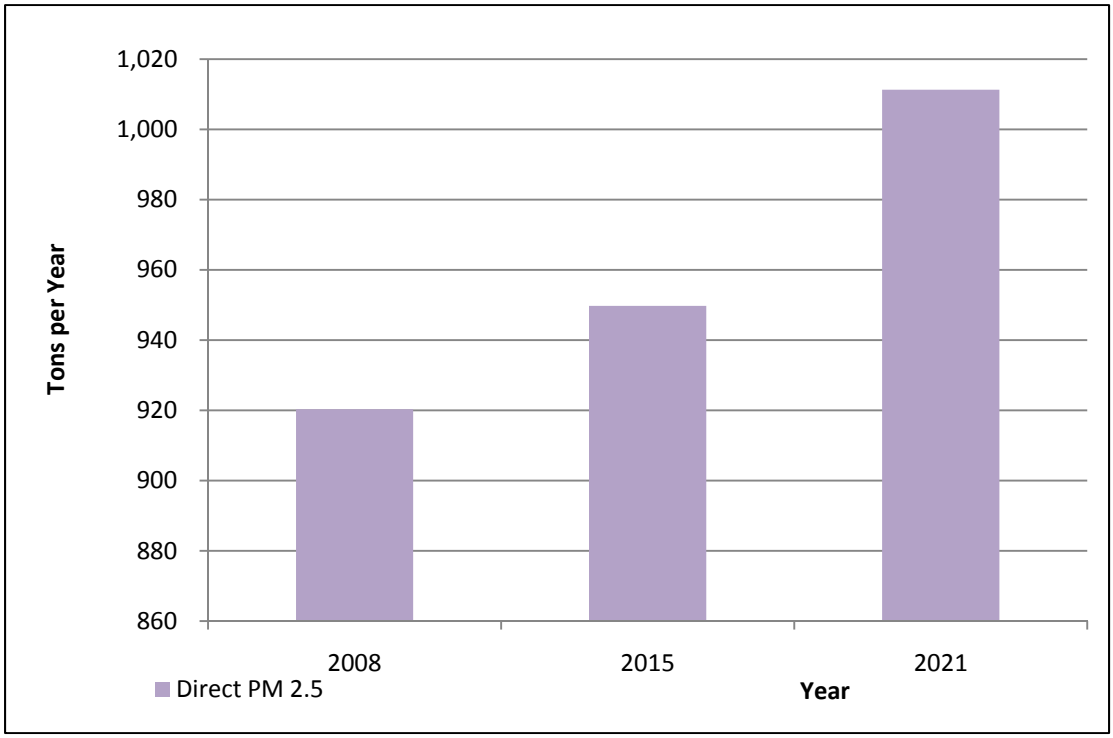
Comparison of 2008 and 2015 and 2021 Projected NO_x Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR



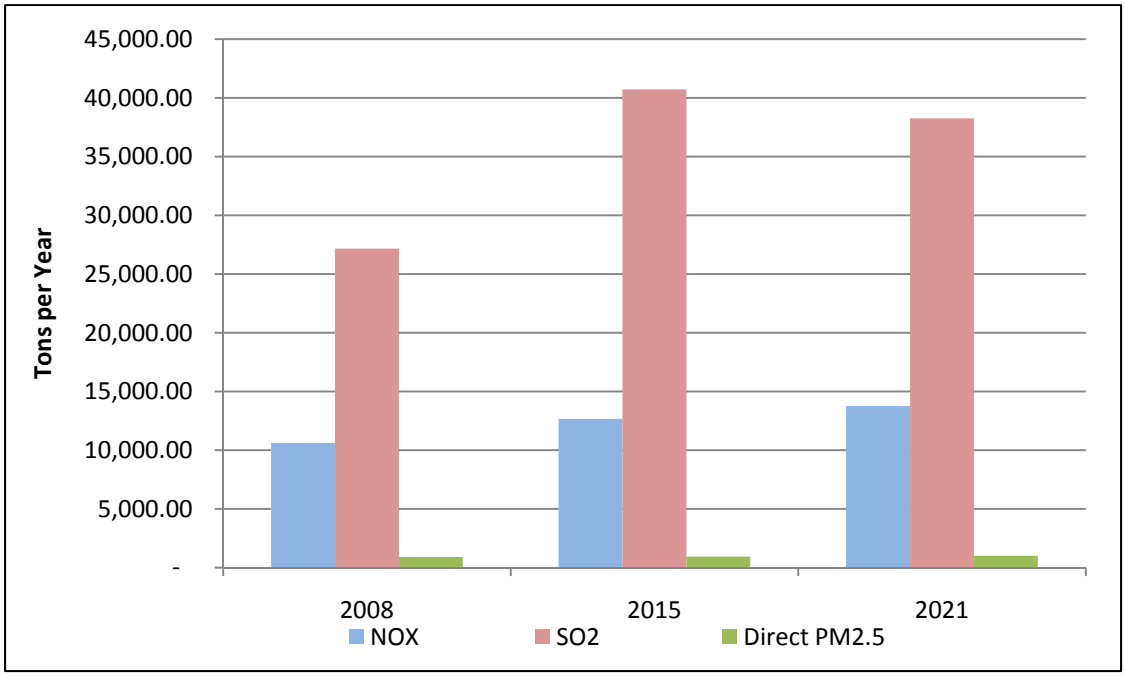
Comparison of 2008 and 2015 and 2021 Projected SO_2 Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR



Comparison of 2008 and 2015 and 2021 Projected Direct $PM_{2.5}$ Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR



Comparison of 2008 and 2015 and 2021 Projected SO_2, NO_x and Direct $PM_{2.5}$ Emissions, Lawrenceburg Township, Dearborn County, Indiana-With CAIR



2008 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
$PM_{2.5}$	**DEARBORN COUNTY, IN**	29.89	19.91	4.29	804.18	62.02	**920.29**
	BOONE COUNTY, KY	251.85	310.52	353.71	76.70	68.81	**1,061.59**
	CAMPBELL COUNTY, KY	146.46	76.09	201.26	0.00	89.52	**513.33**
	KENTON COUNTY, KY	29.89	110.61	366.69	0.00	11.11	**518.30**
	BUTLER COUNTY, OH	377.64	185.81	180.43	16.78	1,045.15	**1,805.81**
	CLERMONT COUNTY, OH	256.60	95.48	196.15	532.61	3.86	**1,084.70**
	HAMILTON COUNTY, OH	1,080.54	345.12	323.94	202.88	158.14	**2,110.62**
	WARREN COUNTY, OH	289.56	124.78	238.33	0.00	19.91	**672.58**
		2,462.43	**1,268.32**	**1,864.80**	**1,633.15**	**1,458.52**	
					GRAND TOTAL		**8,687.22**

2008 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
SO_2	**DEARBORN COUNTY, IN**	2.69	17.38	81.02	25,729.10	1,334.33	**27,164.52**
	BOONE COUNTY, KY	16.71	435.93	1,066.79	2,812.16	17.97	**4,349.56**
	CAMPBELL COUNTY, KY	9.69	206.21	479.14	0.00	0.96	**696.00**
	KENTON COUNTY, KY	16.34	190.40	1,210.42	0.00	13.89	**1,431.05**
	BUTLER COUNTY, OH	34.25	174.34	221.09	2,181.63	5,442.54	**8,053.85**
	CLERMONT COUNTY, OH	23.32	66.25	162.20	42,918.28	118.05	**43,288.10**
	HAMILTON COUNTY, OH	98.30	274.62	161.80	24,693.00	6,552.65	**31,780.37**
	WARREN COUNTY, OH	26.57	34.56	138.31	0.00	3.53	**202.97**
		227.87	**1,399.69**	**3,520.77**	**98,334.17**	**13,483.92**	
					GRAND TOTAL		**116,966.42**

2008 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
NO_x	**DEARBORN COUNTY, IN**	748.81	318.09	145.42	7,429.20	1,979.83	**10,621.35**
	BOONE COUNTY, KY	5,067.94	3,772.42	1,897.28	1,962.59	61.66	**12,761.89**
	CAMPBELL COUNTY, KY	2,988.33	1,833.46	536.71	0.00	49.52	**5,408.02**
	KENTON COUNTY, KY	5,057.93	2,562.60	1,581.60	0.00	20.44	**9,222.57**
	BUTLER COUNTY, OH	9,803.70	2,833.89	807.64	856.92	3,940.28	**18,242.43**
	CLERMONT COUNTY, OH	6,516.40	1,284.92	619.27	24,233.18	42.71	**32,696.48**
	HAMILTON COUNTY, OH	27,020.93	5,402.04	1,955.47	12,372.00	2,652.79	**49,403.23**
	WARREN COUNTY, OH	7,267.18	1,607.45	432.28	0.00	1,043.27	**10,350.18**
		64,471.22	**19,614.87**	**7,975.67**	**46,853.89**	**9,790.50**	
					GRAND TOTAL		**148,706.15**

2015 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
$PM_{2.5}$	**DEARBORN COUNTY, IN**	25.14	13.34	4.11	847.16	60.00	**949.75**
	BOONE COUNTY, KY	151.35	268.43	359.57	80.70	84.35	**944.40**
	CAMPBELL COUNTY, KY	82.36	57.43	200.05	0.00	101.84	**441.68**
	KENTON COUNTY, KY	137.40	83.03	363.77	0.00	13.50	**597.70**
	BUTLER COUNTY, OH	301.16	125.76	180.86	15.86	1,254.70	**1,878.34**
	CLERMONT COUNTY, OH	204.32	66.05	193.49	651.88	6.42	**1,122.16**
	HAMILTON COUNTY, OH	826.00	242.40	330.03	554.65	171.28	**2,124.36**
	WARREN COUNTY, OH	242.05	81.22	233.88	0.00	19.01	**576.16**
		1,969.78	**937.66**	**1,865.76**	**2,150.25**	**1,711.10**	
						GRAND TOTAL	**8,634.55**

2015 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
SO_2	**DEARBORN COUNTY, IN**	2.87	4.73	77.64	39,295.70	1,335.94	**40,716.88**
	BOONE COUNTY, KY	20.67	328.37	1,093.47	2,617.84	19.50	**4,079.85**
	CAMPBELL COUNTY, KY	11.21	149.28	491.66	0.00	1.04	**653.19**
	KENTON COUNTY, KY	18.62	127.09	1,238.92	0.00	15.16	**1,399.79**
	BUTLER COUNTY, OH	34.28	77.70	209.01	654.49	6,847.48	**7,822.96**
	CLERMONT COUNTY, OH	23.34	13.31	151.29	32,590.92	148.28	**32,927.14**
	HAMILTON COUNTY, OH	94.43	93.43	151.81	16,390.65	7,739.34	**24,469.66**
	WARREN COUNTY, OH	27.77	34.11	131.36	0.00	3.45	**196.69**
		233.19	**828.02**	**3,545.16**	**91,549.60**	**16,110.19**	
						GRAND TOTAL	**112,266.16**

2015 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
NO_x	**DEARBORN COUNTY, IN**	482.33	219.83	143.39	9,862.76	1,965.19	**12,673.50**
	BOONE COUNTY, KY	2,788.45	2,892.72	1,985.25	1,504.39	66.48	**9,237.29**
	CAMPBELL COUNTY, KY	1,570.14	1,345.37	563.83	0.00	53.81	**3,533.15**
	KENTON COUNTY, KY	2,637.63	1,848.86	1,654.75	0.00	21.79	**6,163.03**
	BUTLER COUNTY, OH	6,064.61	1,774.59	811.94	343.95	4,626.45	**13,621.54**
	CLERMONT COUNTY, OH	3,993.63	814.05	620.94	16,491.26	60.83	**21,980.71**
	HAMILTON COUNTY, OH	15,925.19	3,374.79	1,974.77	7,236.90	2,943.73	**31,455.38**
	WARREN COUNTY, OH	4,598.44	979.43	434.26	0.00	1,035.29	**7,047.42**
		38,060.42	**13,249.64**	**8,189.13**	**35,439.26**	**10,773.57**	
						GRAND TOTAL	**105,712.02**

2021 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
$PM_{2.5}$	**DEARBORN COUNTY, IN**	18.11	9.07	3.98	922.81	57.32	**1,011.29**
	BOONE COUNTY, KY	114.05	236.53	364.58	83.42	98.94	**897.52**
	CAMPBELL COUNTY, KY	60.09	41.99	199.32	0.00	112.39	**413.79**
	KENTON COUNTY, KY	101.24	59.98	361.65	0.00	15.76	**538.63**
	BUTLER COUNTY, OH	215.76	73.41	182.45	15.59	1,337.03	**1,824.24**
	CLERMONT COUNTY, OH	145.39	40.37	191.83	711.22	7.33	**1,096.14**
	HAMILTON COUNTY, OH	571.48	152.80	338.37	708.74	179.45	**1,950.84**
	WARREN COUNTY, OH	177.61	43.32	230.65	0.00	18.60	**470.18**
		1,403.73	**657.47**	**1,872.83**	**2,441.78**	**1,826.82**	
					GRAND TOTAL		**8,202.63**

2021 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
SO_2	**DEARBORN COUNTY, IN**	3.19	1.14	75.69	36,843.66	1,337.95	**38,261.63**
	BOONE COUNTY, KY	24.37	250.36	1,116.53	2,534.56	21.01	**3,946.83**
	CAMPBELL COUNTY, KY	12.77	103.78	502.75	0.00	1.09	**620.39**
	KENTON COUNTY, KY	21.48	78.99	1,263.63	0.00	16.41	**1,380.51**
	BUTLER COUNTY, OH	37.90	50.24	198.96	0.00	6,828.13	**7,115.23**
	CLERMONT COUNTY, OH	25.66	1.21	142.32	20,589.16	160.98	**20,919.33**
	HAMILTON COUNTY, OH	100.82	36.13	143.71	7,508.46	8,309.88	**16,099.00**
	WARREN COUNTY, OH	31.58	36.61	125.59	0.00	3.42	**197.20**
		257.77	**558.46**	**3,569.18**	**67,475.84**	**16,678.87**	
					GRAND TOTAL		**88,540.12**

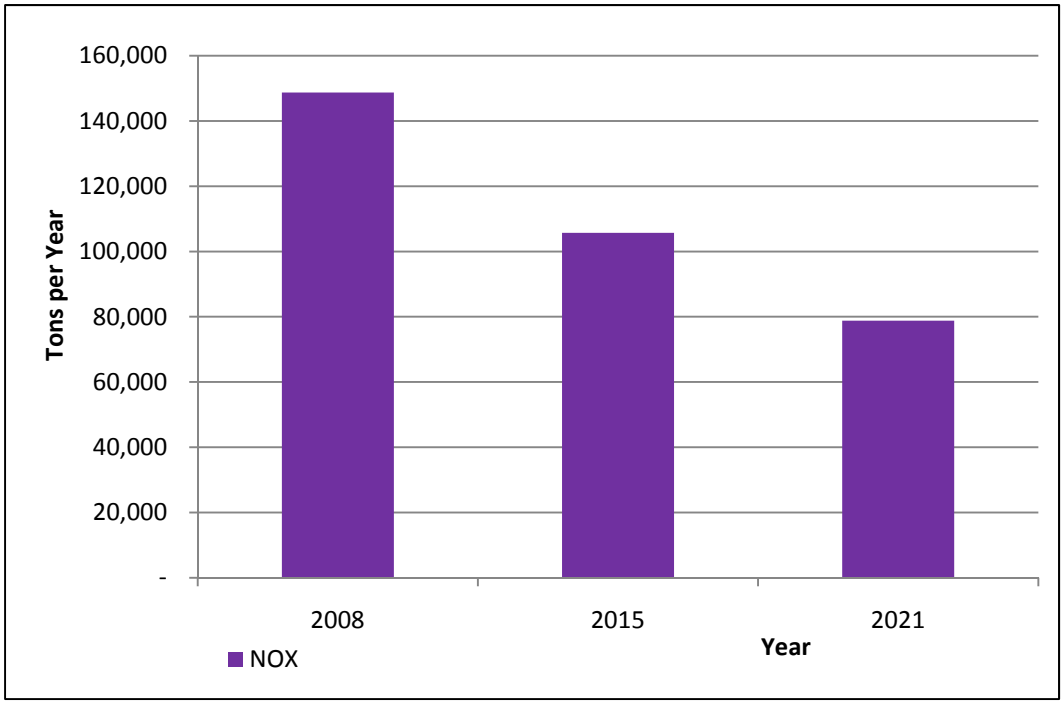
2021 Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area (Tons Per Year)

		ONROAD	NONROAD	AREA	EGU	POINT	TOTAL
NO_x	**DEARBORN COUNTY, IN**	297.95	154.18	142.90	11,229.31	1,943.22	**13,767.56**
	BOONE COUNTY, KY	1,772.72	2,189.66	2,063.30	1,308.08	71.21	**7,404.97**
	CAMPBELL COUNTY, KY	985.28	951.58	587.37	0.00	55.21	**2,579.44**
	KENTON COUNTY, KY	1,677.96	1,269.32	1,718.86	0.00	23.09	**4,689.23**
	BUTLER COUNTY, OH	3,757.91	870.06	817.28	124.10	4,686.11	**10,255.46**
	CLERMONT COUNTY, OH	2,449.31	412.09	623.36	10,451.28	68.68	**14,004.72**
	HAMILTON COUNTY, OH	9,530.16	1,630.33	1,995.51	5,036.15	3,139.37	**21,331.52**
	WARREN COUNTY, OH	2,875.72	439.48	436.82	0.00	1,034.26	**4,786.28**
		23,347.01	**7,916.70**	**8,385.40**	**28,148.92**	**11,021.15**	
					GRAND TOTAL		**78,819.18**

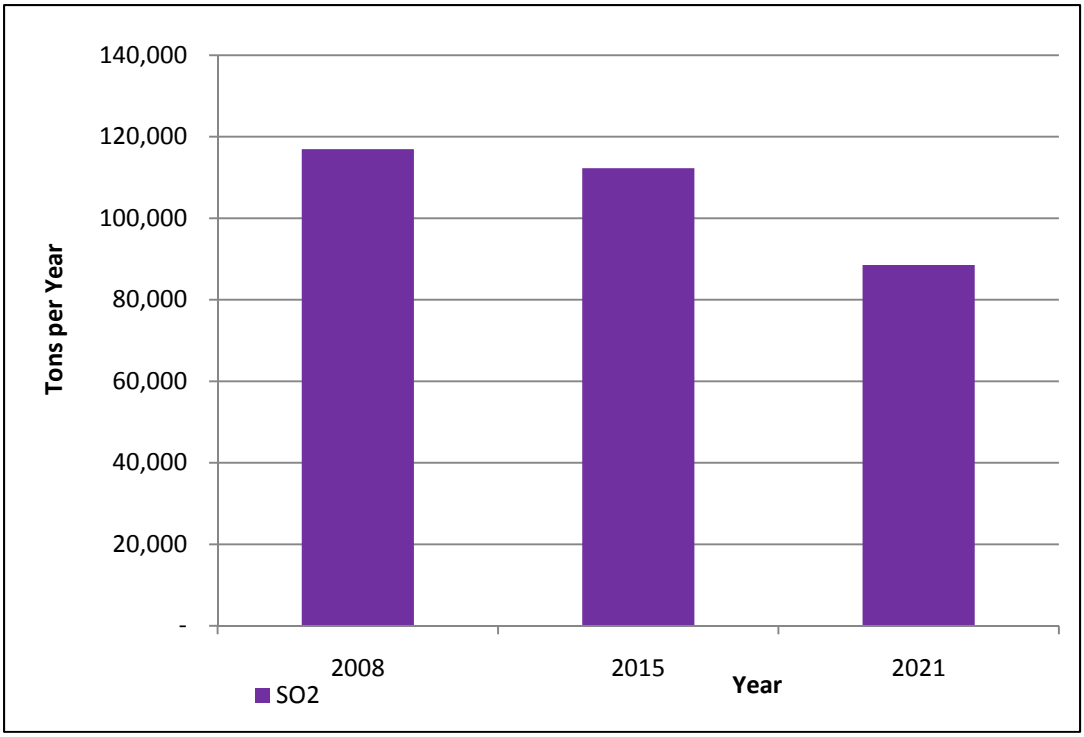
Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area Percent Change (Tons Per Year)

	2008	2021	Change	% Change
NO_x	148,706.15	78,819.18	-69,886.97	-46.9%
SO_2	116,966.42	88,540.12	-28,426.30	-24.3%
Direct $PM_{2.5}$	8,687.22	8,202.63	-484.59	-5.5%

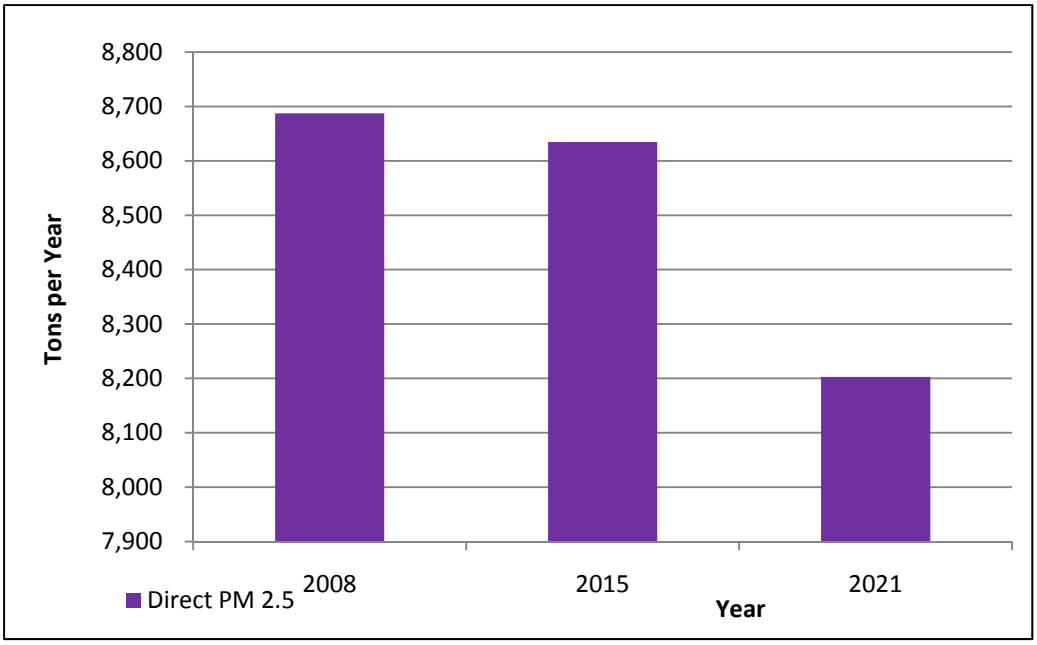
Comparison of 2008 and 2015 and 2021 Projected NO_x Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-With CAIR



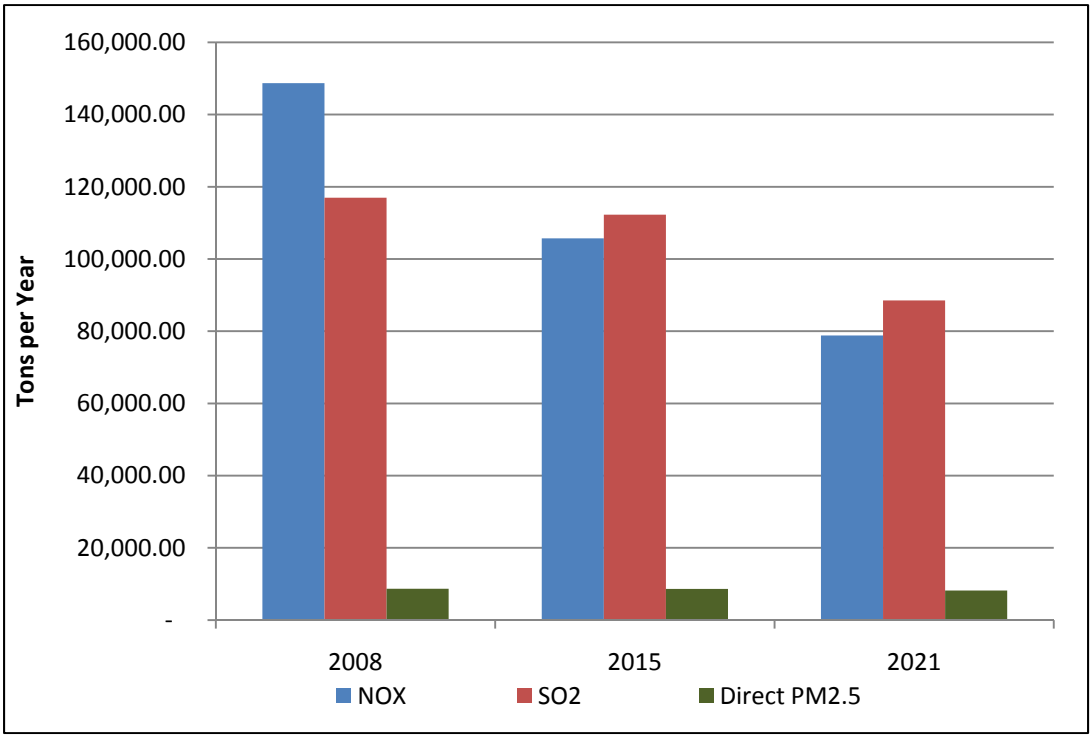
Comparison of 2008 and 2015 and 2021 Projected SO_2 Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-With CAIR



Comparison of 2008 and 2015 and 2021 Projected Direct $PM_{2.5}$ Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-IN/KY-With CAIR, OH-Without CAIR



Comparison of 2008 and 2015 and 2021 Projected SO_2, NO_x and Direct $PM_{2.5}$ Emissions for the Entire Cincinnati-Hamilton, OH-KY-IN Nonattainment Area-(NO_x and SO_2 With CAIR, IN/KY $PM_{2.5}$ With CAIR, OH $PM_{2.5}$-Without CAIR)



APPENDIX F

Mobile Source Input/Output Calculation Files

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Mobile Source Emissions Inventory for Cincinnati PM2.5 Nonattainment Area

Includes a portion of Dearborn County, Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. Emission estimates for the Year 2005, 2008, 2011, 2015, 2018, and 2021 developed in support of the PM2.5 State Implementation Plan

August 2010

Prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency by

OKI Regional Council of Governments

OKI
Ohio · Kentucky · Indiana
Regional Council of Governments

Acknowledgments

Title	Mobile Source Emissions Inventory for Cincinnati PM2.5 Nonattainment Area
Abstract	This report was prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency. The Cincinnati PM2.5 nonattainment area includes a portion of Dearborn County Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. This report includes emission estimates for the years 2005, 2008, 2011, 2015, 2018 and 2021 was generated to support the attainment SIPs for the annual PM2.5 standard. EPA's Motor Vehicle Emission Simulation (MOVES) 2010 was used to generate the emission rates.
Date	August 2010
Agency	Ohio-Kentucky-Indiana Regional Council of Governments Mark Policinski, Executive Director Robert Koehler, P.E., Deputy Director
Project Manager	Andrew J. Reser, AICP
Project Staff	Harikishan Perugu, PTP Larry Buckler

The preparation of this document was financed cooperatively by the Federal Highway Administration, the Federal Transit Administration, the Commonwealth of Kentucky Transportation Cabinet, the Ohio Department of Transportation, and the units of local and county government in the OKI region. The opinions, findings, and conclusions expressed in this document are those of the OKI Regional Council of Governments and are not necessarily those of the U.S. Department of Transportation. This report does not constitute a standard, specification, or regulation.

MOBILE Source Emissions Inventory for the Cincinnati PM2.5 nonattainment area

This report was prepared for the Indiana Department of Environmental Management, the Kentucky Division for Air Quality and the Ohio Environmental Protection Agency. The Cincinnati PM2.5 nonattainment area includes a portion of Dearborn County Indiana, the counties of Boone, Campbell, Kenton in Kentucky, and the counties of Butler, Clermont, Hamilton, and Warren in Ohio. This report includes emission estimates for the years 2005, 2008, 2011, 2015, 2018 and 2021 was generated to support the attainment SIPs for the annual PM2.5 standard. EPA's Motor Vehicle Emissions Simulator (MOVES) 2010 model was used to generate the vehicle emission rates. In December 2009, MOVES replaced MOBILE6.2 as the EPA's official emission factor model. Technical details on OKI's use of MOVES can be found in the Appendix. The OKI travel demand model version 7.6 was used to generate VMT and speed estimates. MOVES emission rates were generated for direct PM2.5, PM2.5 tirewear, PM2.5 brakewear, NO_x and SO^2.

OKI, as the MPO, is responsible for transportation planning and air quality/transportation conformity. Transportation conformity is a mechanism to ensure that federal funding and approval are given to those transportation activities that are consistent with the air quality goals of the State Implementation Plans (SIPs) for Indiana, Kentucky and Ohio. The SIPs include an inventory of projected emissions from vehicles. One or more of the analysis years in the projected inventory may be designated as the motor vehicle emissions budget (MVEB). This budget establishes a maximum allowable limit on future emissions from vehicles (mobile sources). OKI's transportation plans and programs must be shown to be in conformity with all SIP provisions. The conformity process is a quantitative analysis, using U.S.EPA's vehicle emissions software (currently MOVES), demonstrating that forecasted regional vehicle emissions do not exceed the established budget.

Table 1 shows daily and annual mobile source emissions for the combined Indiana and Ohio portions of the nonattainment area, as well as the Kentucky portion of the nonattainment area. Separate MVEB's are typically designated for these two areas. Although official federal guidance on the use of MOVES for PM2.5 SIP development was not available at the time of this analysis, the Federal Highway Administration (FHWA) along with state and local air quality staff were consulted periodically throughout the development of these emissions. An additional safety margin should be added to the MVEB's due uncertainty with growth assumptions utilized in the OKI travel demand model and uncertainty regarding the use of MOVES. Daily and annual mobile source emissions for each county in the nonattainment area are shown in Table 2.

Table 1. Mobile Source Emissions for the Cincinnati PM2.5 Nonattainment Area (tons)

Year	Pollutant Name	DailyEmissions	AnnualEmissions

Kentucky Portion of NA Area

2005 Vehicle Population: 364,081 Daily VMT: 9,621,110 Annual VMT: 3,289,109,202

Oxides of Nitrogen	39.10	13,496.54
Primary Exhaust PM2.5 - Total	1.36	466.23
Primary PM2.5 - Brakewear Particulate	0.16	54.04
Primary PM2.5 - Tirewear Particulate	0.05	17.52
Sulfur Dioxide (SO2)	0.12	41.46

2008 Vehicle Population: 375,873 Daily VMT: 9,991,179 Annual VMT: 3,425,339,505

Oxides of Nitrogen	37.91	13,114.20
Primary Exhaust PM2.5 - Total	1.64	562.84
Primary PM2.5 - Brakewear Particulate	0.18	62.10
Primary PM2.5 - Tirewear Particulate	0.06	20.70
Sulfur Dioxide (SO2)	0.12	42.74

2011 Vehicle Population: 381,911 Daily VMT: 10,490,143 Annual VMT: 3,587,796,186

Oxides of Nitrogen	29.33	10,141.52
Primary Exhaust PM2.5 - Total	1.19	407.74
Primary PM2.5 - Brakewear Particulate	0.20	68.38
Primary PM2.5 - Tirewear Particulate	0.07	22.68
Sulfur Dioxide (SO2)	0.13	45.36

2015 Vehicle Population: 394,278 Daily VMT: 11,495,496 Annual VMT: 3,931,385,741

Oxides of Nitrogen	20.18	6,996.21
Primary Exhaust PM2.5 - Total	0.78	267.30
Primary PM2.5 - Brakewear Particulate	0.23	77.94
Primary PM2.5 - Tirewear Particulate	0.08	25.88
Sulfur Dioxide (SO2)	0.15	50.50

2018 Vehicle Population: 403,817 Daily VMT: 12,173,549 Annual VMT: 4,163,203,435

Oxides of Nitrogen	15.78	5,480.81
Primary Exhaust PM2.5 - Total	0.59	202.15
Primary PM2.5 - Brakewear Particulate	0.27	91.15
Primary PM2.5 - Tirewear Particulate	0.09	30.09
Sulfur Dioxide (SO2)	0.16	56.28

2021 Vehicle Population: 413,587 Daily VMT: 12,534,236 Annual VMT: 4,286,834,360

Oxides of Nitrogen	12.75	4,435.96
Primary Exhaust PM2.5 - Total	0.43	146.79
Primary PM2.5 - Brakewear Particulate	0.28	96.84
Primary PM2.5 - Tirewear Particulate	0.09	31.74
Sulfur Dioxide (SO2)	0.17	58.63

Year	Pollutant Name	DailyEmissions	AnnualEmissions

Ohio/Indiana Portion of NA Area

2005 Vehicle Population: 1,754,582 Daily VMT: 39,564,030 Annual VMT: 13,541,324,003

Oxides of Nitrogen	168.89	58,423.36
Primary Exhaust PM2.5 - Total	5.74	1,979.63
Primary PM2.5 - Brakewear Particulate	0.65	223.20
Primary PM2.5 - Tirewear Particulate	0.20	69.67
Sulfur Dioxide (SO2)	0.48	165.35

2008 Vehicle Population: 1,811,406 Daily VMT: 40,858,751 Annual VMT: 14,015,754,874

Oxides of Nitrogen	148.02	51,357.02
Primary Exhaust PM2.5 - Total	4.85	1,675.04
Primary PM2.5 - Brakewear Particulate	0.80	273.84
Primary PM2.5 - Tirewear Particulate	0.25	85.37
Sulfur Dioxide (SO2)	0.54	185.13

2011 Vehicle Population: 1,840,505 Daily VMT: 42,044,841 Annual VMT: 14,383,526,419

Oxides of Nitrogen	135.95	47,061.53
Primary Exhaust PM2.5 - Total	5.54	1,904.61
Primary PM2.5 - Brakewear Particulate	0.85	290.00
Primary PM2.5 - Tirewear Particulate	0.27	91.52
Sulfur Dioxide (SO2)	0.53	182.01

2015 Vehicle Population: 1,900,111 Daily VMT: 43,316,281 Annual VMT: 14,830,453,053

Oxides of Nitrogen	89.45	31,064.21
Primary Exhaust PM2.5 - Total	3.57	1,227.86
Primary PM2.5 - Brakewear Particulate	0.82	280.25
Primary PM2.5 - Tirewear Particulate	0.26	90.54
Sulfur Dioxide (SO2)	0.53	182.69

2018 Vehicle Population: 1,946,080 Daily VMT: 45,314,292 Annual VMT: 15,513,701,656

Oxides of Nitrogen	70.34	24,451.43
Primary Exhaust PM2.5 - Total	2.78	958.57
Primary PM2.5 - Brakewear Particulate	0.90	307.39
Primary PM2.5 - Tirewear Particulate	0.29	99.03
Sulfur Dioxide (SO2)	0.57	195.09

2021 Vehicle Population: 1,993,161 Daily VMT: 46,689,707 Annual VMT: 15,521,916,278

Oxides of Nitrogen	55.50	18,911.05
Primary Exhaust PM2.5 - Total	2.10	705.30
Primary PM2.5 - Brakewear Particulate	0.96	320.17
Primary PM2.5 - Tirewear Particulate	0.31	102.89
Sulfur Dioxide (SO2)	0.60	199.14

Table 2. Mobile Source Emissions by County for the Cincinnati PM2.5 Nonattainment Area (tons)

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Indiana

Dearborn NA

2005 Vehicle Population: 24,915 Daily VMT: 578,642 Annual VMT: 196,738,031

Oxides of Nitrogen	2.40	865.46
Primary Exhaust PM2.5 - Total	0.08	29.68
Primary PM2.5 - Brakewear Particulate	0.01	3.28
Primary PM2.5 - Tirewear Particulate	0.00	1.02
Sulfur Dioxide (SO2)	0.01	2.45

2008 Vehicle Population: 25,722 Daily VMT: 587,583 Annual VMT: 199,778,078

Oxides of Nitrogen	2.09	748.81
Primary Exhaust PM2.5 - Total	0.07	24.72
Primary PM2.5 - Brakewear Particulate	0.01	3.94
Primary PM2.5 - Tirewear Particulate	0.00	1.23
Sulfur Dioxide (SO2)	0.01	2.69

2011 Vehicle Population: 26,135 Daily VMT: 605,621 Annual VMT: 205,911,005

Oxides of Nitrogen	1.92	685.40
Primary Exhaust PM2.5 - Total	0.08	27.88
Primary PM2.5 - Brakewear Particulate	0.01	4.19
Primary PM2.5 - Tirewear Particulate	0.00	1.32
Sulfur Dioxide (SO2)	0.01	2.65

2015 Vehicle Population: 26,982 Daily VMT: 657,779 Annual VMT: 223,644,622

Oxides of Nitrogen	1.31	482.33
Primary Exhaust PM2.5 - Total	0.05	19.43
Primary PM2.5 - Brakewear Particulate	0.01	4.32
Primary PM2.5 - Tirewear Particulate	0.00	1.39
Sulfur Dioxide (SO2)	0.01	2.87

2018 Vehicle Population: 27,635 Daily VMT: 684,362 Annual VMT: 232,682,971

Oxides of Nitrogen	1.03	376.85
Primary Exhaust PM2.5 - Total	0.04	15.09
Primary PM2.5 - Brakewear Particulate	0.01	4.70
Primary PM2.5 - Tirewear Particulate	0.00	1.51
Sulfur Dioxide (SO2)	0.01	3.04

2021 Vehicle Population: 28,303 Daily VMT: 706,829 Annual VMT: 240,321,759

Oxides of Nitrogen	0.81	297.95
Primary Exhaust PM2.5 - Total	0.03	11.44
Primary PM2.5 - Brakewear Particulate	0.01	5.05
Primary PM2.5 - Tirewear Particulate	0.00	1.62
Sulfur Dioxide (SO2)	0.01	3.19

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Kentucky

Boone

2005 Vehicle Population: 129,823 Daily VMT: 3,924,117 Annual VMT: 1,273,226,967

Oxides of Nitrogen	14.94	5,126.88
Primary Exhaust PM2.5 - Total	0.52	177.58
Primary PM2.5 - Brakewear Particulate	0.06	20.86
Primary PM2.5 - Tirewear Particulate	0.02	6.77
Sulfur Dioxide (SO2)	0.05	15.91

2008 Vehicle Population: 134,028 Daily VMT: 4,076,584 Annual VMT: 1,350,001,539

Oxides of Nitrogen	14.73	5,067.94
Primary Exhaust PM2.5 - Total	0.64	219.29
Primary PM2.5 - Brakewear Particulate	0.07	24.42
Primary PM2.5 - Tirewear Particulate	0.02	8.14
Sulfur Dioxide (SO2)	0.05	16.71

2011 Vehicle Population: 136,181 Daily VMT: 4,383,716 Annual VMT: 1,448,879,491

Oxides of Nitrogen	11.61	3,990.01
Primary Exhaust PM2.5 - Total	0.48	162.47
Primary PM2.5 - Brakewear Particulate	0.08	27.55
Primary PM2.5 - Tirewear Particulate	0.03	9.14
Sulfur Dioxide (SO2)	0.05	18.16

2015 Vehicle Population: 140,590 Daily VMT: 4,950,741 Annual VMT: 1,628,041,282

Oxides of Nitrogen	8.11	2,788.45
Primary Exhaust PM2.5 - Total	0.32	108.49
Primary PM2.5 - Brakewear Particulate	0.09	32.17
Primary PM2.5 - Tirewear Particulate	0.03	10.69
Sulfur Dioxide (SO2)	0.06	20.67

2018 Vehicle Population: 143,991 Daily VMT: 5,260,102 Annual VMT: 1,729,595,156

Oxides of Nitrogen	6.34	2,182.28
Primary Exhaust PM2.5 - Total	0.24	82.19
Primary PM2.5 - Brakewear Particulate	0.11	37.76
Primary PM2.5 - Tirewear Particulate	0.04	12.47
Sulfur Dioxide (SO2)	0.07	23.14

2021 Vehicle Population: 147,476 Daily VMT: 5,478,224 Annual VMT: 1,800,571,684

Oxides of Nitrogen	5.14	1,772.72
Primary Exhaust PM2.5 - Total	0.18	60.19
Primary PM2.5 - Brakewear Particulate	0.12	40.56
Primary PM2.5 - Tirewear Particulate	0.04	13.30
Sulfur Dioxide (SO2)	0.07	24.37

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Campbell				
	2005	Vehicle Population: 86,065	Daily VMT: 2,286,217	Annual VMT: 741,790,595
		Oxides of Nitrogen	8.87	3,041.21
		Primary Exhaust PM2.5 - Total	0.31	104.22
		Primary PM2.5 - Brakewear Particulate	0.04	12.14
		Primary PM2.5 - Tirewear Particulate	0.01	3.94
		Sulfur Dioxide (SO2)	0.03	9.30
	2008	Vehicle Population: 88,853	Daily VMT: 2,339,542	Annual VMT: 774,762,718
		Oxides of Nitrogen	8.63	2,988.33
		Primary Exhaust PM2.5 - Total	0.37	127.73
		Primary PM2.5 - Brakewear Particulate	0.04	14.05
		Primary PM2.5 - Tirewear Particulate	0.01	4.68
		Sulfur Dioxide (SO2)	0.03	9.69
	2011	Vehicle Population: 90,279	Daily VMT: 2,421,600	Annual VMT: 800,372,692
		Oxides of Nitrogen	6.61	2,287.81
		Primary Exhaust PM2.5 - Total	0.27	91.36
		Primary PM2.5 - Brakewear Particulate	0.04	15.26
		Primary PM2.5 - Tirewear Particulate	0.01	5.06
		Sulfur Dioxide (SO2)	0.03	10.15
	2015	Vehicle Population: 93,204	Daily VMT: 2,663,159	Annual VMT: 875,774,487
		Oxides of Nitrogen	4.55	1,570.14
		Primary Exhaust PM2.5 - Total	0.17	59.30
		Primary PM2.5 - Brakewear Particulate	0.05	17.31
		Primary PM2.5 - Tirewear Particulate	0.02	5.75
		Sulfur Dioxide (SO2)	0.03	11.21
	2018	Vehicle Population: 95,458	Daily VMT: 2,771,476	Annual VMT: 911,300,097
		Oxides of Nitrogen	3.52	1,216.21
		Primary Exhaust PM2.5 - Total	0.13	44.14
		Primary PM2.5 - Brakewear Particulate	0.06	19.90
		Primary PM2.5 - Tirewear Particulate	0.02	6.57
		Sulfur Dioxide (SO2)	0.04	12.28
	2021	Vehicle Population: 97,768	Daily VMT: 2,849,127	Annual VMT: 936,445,352
		Oxides of Nitrogen	2.84	985.28
		Primary Exhaust PM2.5 - Total	0.09	32.07
		Primary PM2.5 - Brakewear Particulate	0.06	21.10
		Primary PM2.5 - Tirewear Particulate	0.02	6.92
		Sulfur Dioxide (SO2)	0.04	12.77

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Kenton				
	2005	Vehicle Population: 148,193	Daily VMT: 3,927,743	Annual VMT: 1,274,091,641
		Oxides of Nitrogen	15.29	5,328.44
		Primary Exhaust PM2.5 - Total	0.53	184.43
		Primary PM2.5 - Brakewear Particulate	0.06	21.04
		Primary PM2.5 - Tirewear Particulate	0.02	6.82
		Sulfur Dioxide (SO2)	0.05	16.24
	2008	Vehicle Population: 152,992	Daily VMT: 3,927,332	Annual VMT: 1,300,575,248
		Oxides of Nitrogen	14.55	5,057.93
		Primary Exhaust PM2.5 - Total	0.62	215.81
		Primary PM2.5 - Brakewear Particulate	0.07	23.63
		Primary PM2.5 - Tirewear Particulate	0.02	7.87
		Sulfur Dioxide (SO2)	0.05	16.34
	2011	Vehicle Population: 155,451	Daily VMT: 4,049,886	Annual VMT: 1,338,544,003
		Oxides of Nitrogen	11.11	3,863.70
		Primary Exhaust PM2.5 - Total	0.45	153.90
		Primary PM2.5 - Brakewear Particulate	0.07	25.57
		Primary PM2.5 - Tirewear Particulate	0.02	8.48
		Sulfur Dioxide (SO2)	0.05	17.05
	2015	Vehicle Population: 160,484	Daily VMT: 4,341,124	Annual VMT: 1,427,569,972
		Oxides of Nitrogen	7.51	2,637.63
		Primary Exhaust PM2.5 - Total	0.29	99.51
		Primary PM2.5 - Brakewear Particulate	0.08	28.45
		Primary PM2.5 - Tirewear Particulate	0.03	9.44
		Sulfur Dioxide (SO2)	0.05	18.62
	2018	Vehicle Population: 164,368	Daily VMT: 4,629,694	Annual VMT: 1,522,308,182
		Oxides of Nitrogen	5.93	2,082.32
		Primary Exhaust PM2.5 - Total	0.22	75.82
		Primary PM2.5 - Brakewear Particulate	0.10	33.49
		Primary PM2.5 - Tirewear Particulate	0.03	11.04
		Sulfur Dioxide (SO2)	0.06	20.86
	2021	Vehicle Population: 168,343	Daily VMT: 4,715,306	Annual VMT: 1,549,817,325
		Oxides of Nitrogen	4.76	1,677.96
		Primary Exhaust PM2.5 - Total	0.16	54.53
		Primary PM2.5 - Brakewear Particulate	0.10	35.19
		Primary PM2.5 - Tirewear Particulate	0.03	11.52
		Sulfur Dioxide (SO2)	0.06	21.48

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Ohio

Butler

2005 Vehicle Population: 401,759 Daily VMT: 7,452,293 Annual VMT: 2,469,168,490

Oxides of Nitrogen	32.00	10,910.37
Primary Exhaust PM2.5 - Total	1.06	361.06
Primary PM2.5 - Brakewear Particulate	0.12	40.31
Primary PM2.5 - Tirewear Particulate	0.04	12.60
Sulfur Dioxide (SO2)	0.09	30.01

2008 Vehicle Population: 414,771 Daily VMT: 7,745,693 Annual VMT: 2,598,061,793

Oxides of Nitrogen	28.56	9,803.70
Primary Exhaust PM2.5 - Total	0.91	311.45
Primary PM2.5 - Brakewear Particulate	0.15	50.45
Primary PM2.5 - Tirewear Particulate	0.05	15.74
Sulfur Dioxide (SO2)	0.10	34.25

2011 Vehicle Population: 421,434 Daily VMT: 8,050,709 Annual VMT: 2,693,718,927

Oxides of Nitrogen	26.50	9,074.89
Primary Exhaust PM2.5 - Total	1.05	356.91
Primary PM2.5 - Brakewear Particulate	0.16	53.99
Primary PM2.5 - Tirewear Particulate	0.05	17.06
Sulfur Dioxide (SO2)	0.10	34.00

2015 Vehicle Population: 435,082 Daily VMT: 8,361,495 Annual VMT: 2,792,190,918

Oxides of Nitrogen	17.64	6,064.61
Primary Exhaust PM2.5 - Total	0.68	231.78
Primary PM2.5 - Brakewear Particulate	0.16	52.42
Primary PM2.5 - Tirewear Particulate	0.05	16.96
Sulfur Dioxide (SO2)	0.10	34.28

2018 Vehicle Population: 445,608 Daily VMT: 8,806,051 Annual VMT: 2,940,852,857

Oxides of Nitrogen	13.98	4,813.27
Primary Exhaust PM2.5 - Total	0.54	182.29
Primary PM2.5 - Brakewear Particulate	0.17	57.91
Primary PM2.5 - Tirewear Particulate	0.06	18.68
Sulfur Dioxide (SO2)	0.11	36.85

2021 Vehicle Population: 456,389 Daily VMT: 9,150,040 Annual VMT: 2,966,040,396

Oxides of Nitrogen	11.13	3,757.91
Primary Exhaust PM2.5 - Total	0.41	135.39
Primary PM2.5 - Brakewear Particulate	0.19	60.81
Primary PM2.5 - Tirewear Particulate	0.06	19.56
Sulfur Dioxide (SO2)	0.12	37.90

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions

Clermont

2005 Vehicle Population: 232,380 Daily VMT: 5,083,336 Annual VMT: 1,684,261,582

Oxides of Nitrogen	21.21	7,295.87
Primary Exhaust PM2.5 - Total	0.72	245.48
Primary PM2.5 - Brakewear Particulate	0.08	27.67
Primary PM2.5 - Tirewear Particulate	0.03	8.64
Sulfur Dioxide (SO2)	0.06	20.51

2008 Vehicle Population: 239,906 Daily VMT: 5,262,494 Annual VMT: 1,765,146,867

Oxides of Nitrogen	18.81	6,516.40
Primary Exhaust PM2.5 - Total	0.61	211.40
Primary PM2.5 - Brakewear Particulate	0.10	34.46
Primary PM2.5 - Tirewear Particulate	0.03	10.74
Sulfur Dioxide (SO2)	0.07	23.32

2011 Vehicle Population: 243,760 Daily VMT: 5,489,550 Annual VMT: 1,836,770,645

Oxides of Nitrogen	17.48	6,039.51
Primary Exhaust PM2.5 - Total	0.71	243.25
Primary PM2.5 - Brakewear Particulate	0.11	37.00
Primary PM2.5 - Tirewear Particulate	0.03	11.68
Sulfur Dioxide (SO2)	0.07	23.23

2015 Vehicle Population: 251,654 Daily VMT: 5,687,704 Annual VMT: 1,899,319,930

Oxides of Nitrogen	11.54	3,993.63
Primary Exhaust PM2.5 - Total	0.46	156.92
Primary PM2.5 - Brakewear Particulate	0.11	35.82
Primary PM2.5 - Tirewear Particulate	0.03	11.58
Sulfur Dioxide (SO2)	0.07	23.34

2018 Vehicle Population: 257,742 Daily VMT: 5,952,609 Annual VMT: 1,987,922,558

Oxides of Nitrogen	9.09	3,146.47
Primary Exhaust PM2.5 - Total	0.36	122.57
Primary PM2.5 - Brakewear Particulate	0.12	39.31
Primary PM2.5 - Tirewear Particulate	0.04	12.67
Sulfur Dioxide (SO2)	0.07	24.94

2021 Vehicle Population: 263,978 Daily VMT: 6,186,447 Annual VMT: 2,005,373,961

Oxides of Nitrogen	7.22	2,449.31
Primary Exhaust PM2.5 - Total	0.27	90.84
Primary PM2.5 - Brakewear Particulate	0.12	41.28
Primary PM2.5 - Tirewear Particulate	0.04	13.27
Sulfur Dioxide (SO2)	0.08	25.66

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Hamilton				
	2005	Vehicle Population: 862,422	Daily VMT: 21,859,473	Annual VMT: 7,241,536,812
		Oxides of Nitrogen	89.30	31,127.09
		Primary Exhaust PM2.5 - Total	3.06	1,064.67
		Primary PM2.5 - Brakewear Particulate	0.35	119.94
		Primary PM2.5 - Tirewear Particulate	0.11	37.41
		Sulfur Dioxide (SO2)	0.26	88.85
	2008	Vehicle Population: 890,352	Daily VMT: 22,124,524	Annual VMT: 7,421,012,594
		Oxides of Nitrogen	77.45	27,020.93
		Primary Exhaust PM2.5 - Total	2.56	889.81
		Primary PM2.5 - Brakewear Particulate	0.42	145.42
		Primary PM2.5 - Tirewear Particulate	0.13	45.31
		Sulfur Dioxide (SO2)	0.28	98.30
	2011	Vehicle Population: 904,655	Daily VMT: 22,426,043	Annual VMT: 7,503,619,525
		Oxides of Nitrogen	70.18	24,435.59
		Primary Exhaust PM2.5 - Total	2.88	997.06
		Primary PM2.5 - Brakewear Particulate	0.44	151.73
		Primary PM2.5 - Tirewear Particulate	0.14	47.86
		Sulfur Dioxide (SO2)	0.28	95.30
	2015	Vehicle Population: 933,953	Daily VMT: 22,849,516	Annual VMT: 7,630,239,650
		Oxides of Nitrogen	45.58	15,925.19
		Primary Exhaust PM2.5 - Total	1.83	634.62
		Primary PM2.5 - Brakewear Particulate	0.42	144.67
		Primary PM2.5 - Tirewear Particulate	0.14	46.71
		Sulfur Dioxide (SO2)	0.27	94.43
	2018	Vehicle Population: 956,548	Daily VMT: 23,630,577	Annual VMT: 7,891,625,119
		Oxides of Nitrogen	35.51	12,422.37
		Primary Exhaust PM2.5 - Total	1.41	490.62
		Primary PM2.5 - Brakewear Particulate	0.45	156.90
		Primary PM2.5 - Tirewear Particulate	0.15	50.52
		Sulfur Dioxide (SO2)	0.29	99.78
	2021	Vehicle Population: 979,689	Daily VMT: 24,098,721	Annual VMT: 7,811,745,310
		Oxides of Nitrogen	27.80	9,530.16
		Primary Exhaust PM2.5 - Total	1.06	357.87
		Primary PM2.5 - Brakewear Particulate	0.48	161.69
		Primary PM2.5 - Tirewear Particulate	0.15	51.92
		Sulfur Dioxide (SO2)	0.30	100.82

County	Year	Pollutant Name	DailyEmissions	AnnualEmissions
Warren				
	2005	Vehicle Population: 233,106	Daily VMT: 5,884,222	Annual VMT: 1,949,619,088
		Oxides of Nitrogen	23.98	8,224.57
		Primary Exhaust PM2.5 - Total	0.82	278.74
		Primary PM2.5 - Brakewear Particulate	0.09	32.00
		Primary PM2.5 - Tirewear Particulate	0.03	10.00
		Sulfur Dioxide (SO2)	0.07	23.54
	2008	Vehicle Population: 240,655	Daily VMT: 6,057,344	Annual VMT: 2,031,755,542
		Oxides of Nitrogen	21.11	7,267.18
		Primary Exhaust PM2.5 - Total	0.69	237.65
		Primary PM2.5 - Brakewear Particulate	0.12	39.57
		Primary PM2.5 - Tirewear Particulate	0.04	12.34
		Sulfur Dioxide (SO2)	0.08	26.57
	2011	Vehicle Population: 244,521	Daily VMT: 6,406,290	Annual VMT: 2,143,506,318
		Oxides of Nitrogen	19.88	6,826.15
		Primary Exhaust PM2.5 - Total	0.82	279.53
		Primary PM2.5 - Brakewear Particulate	0.13	43.09
		Primary PM2.5 - Tirewear Particulate	0.04	13.60
		Sulfur Dioxide (SO2)	0.08	26.83
	2015	Vehicle Population: 252,440	Daily VMT: 6,842,835	Annual VMT: 2,285,057,933
		Oxides of Nitrogen	13.37	4,598.44
		Primary Exhaust PM2.5 - Total	0.54	185.12
		Primary PM2.5 - Brakewear Particulate	0.13	43.02
		Primary PM2.5 - Tirewear Particulate	0.04	13.91
		Sulfur Dioxide (SO2)	0.08	27.77
	2018	Vehicle Population: 258,547	Daily VMT: 7,368,042	Annual VMT: 2,460,618,151
		Oxides of Nitrogen	10.73	3,692.47
		Primary Exhaust PM2.5 - Total	0.43	148.00
		Primary PM2.5 - Brakewear Particulate	0.14	48.57
		Primary PM2.5 - Tirewear Particulate	0.05	15.66
		Sulfur Dioxide (SO2)	0.09	30.49
	2021	Vehicle Population: 264,802	Daily VMT: 7,707,508	Annual VMT: 2,498,434,852
		Oxides of Nitrogen	8.54	2,875.72
		Primary Exhaust PM2.5 - Total	0.33	109.76
		Primary PM2.5 - Brakewear Particulate	0.16	51.34
		Primary PM2.5 - Tirewear Particulate	0.05	16.51
		Sulfur Dioxide (SO2)	0.10	31.58

Mobile Source Emission Forecast Process

Emission Factor Model

OKI's conformity assessment utilized U.S.EPA's emissions model MOVES 2010 to develop emission factors for SO2, NO_X and PM2.5. Table 3 summarizes the settings used in the MOVES run specification file. Table 4 lists the data used in the MOVES County-Data Manager. Further details on the use of MOVES are found in the Appendix.

Table 3.

MOVES Runspec [sic] Parameter	Settings
MOVES Version 2009/12/21, MOVES default database 2010615111524	
Scale	County, Emission Rates
Time Span	Time aggregation = Hour 1 month representing average annual temperatures All hours of day selected Weekdays only
Geographic Bounds	2 Custom Domains – 4 Ohio counties, 3 Kentucky counties
Vehicles/Equipment	All source types, gasoline and diesel
Road Type	All road types including off-network
Pollutants and Processes	NO_x, All PM2.5 categories, SO^2, Total Energy Consumption
Strategies	none
General Output	Units= grams, joules and miles
Output Emissions	Time = hour, Location =county, on-road emission rates by road type and source use type.
Advanced Performance	none

Table 4

County Data Manager	Data Source
Source Type Population	Local and default. Local data (2010) from KYTC and ODOT from motor vehicle registration data. Default data used for source types 41, 61 and 62. In addition , default data for source types 31, 32 and 54 used for KY.
Vehicle Type VMT	Local and default. HPMSVTypeYear VMT=daily VMT from OKI travel demand model with EPA's daily to annual VMT converter applied. monthVMTFraction = default. dayVMTFraction=default, hourVMTFraction=local.
I/M Programs	Default modified to reflect discontinued I/M program
Fuel Formulation	Default

Fuel Supply	Default
Meteorology Data	Local. Kentucky Division for Air Quality.
Ramp Fraction	Local. Ramp emissions calculated outside of MOVES
Road Type Distribution	Local. OKI travel demand model.
Age Distribution	Local and default. Local data (2010) from KYTC and ODOT from motor vehicle registration data. Default data used for source types 41, 61 and 62. In addition , default data for source types 31, 32 and 54 used for KY.
Average Speed Distribution	Local. OKI travel demand model.

OKI Travel Demand Model

Transportation system performance was estimated using the OKI Travel Demand Model Version 7.6. The OKI Travel Demand Model is composed of TRANPLAN programs, CUBE Voyager programs and a series of FORTRAN programs written by OKI. It is a state of the practice model that uses the standard 4 phase sequential modeling approach of trip generation, distribution, modal choice and assignment. The model uses demographic and land use data and capacity and free-flow speed characteristics for each roadway segment in the network to produce a "loaded" highway network with forecasted traffic volumes with revised speeds based on specified speed/capacity relationships.

Travel analysis zones are the basic geographic unit for estimating travel in the OKI model. The OKI region is subdivided into 1608 traffic analysis zones to permit detail as well as manageability. A variety of socioeconomic data items are used in the OKI transportation planning process. These data are used primarily to forecast future travel patterns by serving as independent variables in OKI trip generation equations. The following categories of planning data are utilized:

- Population (household and group quarter)
- Households
- Household vehicles
- Employment (by employment category and zone of work)
- Labor force participation (by zone of residence)
- Area type

The principal data requirements of the OKI travel demand forecasting model are population and employment. From these variables, other characteristics including households, labor force, and personal vehicles may be derived. Chapter 5 of *OKI 2030 Regional Transportation Plan 2008 Update* provides a complete demographic overview of the region.

OKI utilizes both base year (2005) and future year data (2010, 2020 and 2030) in the planning process. Planning data are maintained at the Traffic Analysis Zone (TAZ) level, and originate in the 2000 Census of Population and Housing. Base year 2005 and future year data for each variable are developed through various methods. More detailed explanation of base year and future year data generation for each of the above-mentioned categories of planning data follows. All of the variables represent the latest OKI planning assumptions.

Population

Base and Future Year Data: Population data for base year 2005 and future years 2010, 2020 and 2030 originate with the 2000 Census of Population and Housing. Utilizing ArcView GIS, population data at the zonal level for 2000 was derived from the area proportion allocation of block level population.

As a tri-state regional planning agency, OKI uses county level projections as prepared by the respective state data centers (Ohio Department of Development Office of Strategic Research, Kentucky State Data Center and Indiana Business Research Center) as control totals. The most current projections (years 2005 to 2030) were released by the Ohio and Indiana state data centers in 2003 and the Kentucky State Data Center in 2004. Population projections at the zonal level are calculated by multiplying household size by the projected zonal households. Household size is factored so that, in each county, the sum of the zonal populations equals the control total.

Households

Base Year Data: Household data for base year 2005 originates with the 2000 Census of Population and Housing. Utilizing the geographic information system ArcMap, household data at the zonal level for 2000 was derived from the area proportion allocation of block level households. Year 2000 household data was updated to 2005 with residential building permits issued between January 2000 and December 2004. The residential building locations were geocoded in ArcMap, then aggregated to the TAZs. The housing unit totals for each TAZ were converted to households by applying a vacancy rate, an adjustment for permitted but unbuilt units, and subtracting demolitions (where data was available). These households were then added to the year Census 2000 zonal household total to arrive at 2005 households for each TAZ.

Future Year Data: The preparation of household projections was accomplished by calculating the number of households for a projected county population using ratios of householders to total population by age specific cohorts derived from the 2000 Census for each analysis year. Disaggregation to TAZs was determined by historical trends, existing and future land use, topography, flood plain information, availability of land, local knowledge and other factors.

Household Vehicles

Base and Future Year Data: Base and future year household vehicle data were obtained from the 2000 Census of Population and Housing. The 2000 Census is the only source of household vehicle data available at the block group level. Average vehicles per household were calculated for block groups then applied to the TAZs associated with each block group. The 2005, 2010, 2020 and 2030 vehicles per household level was held at the 2000 level based on the fact that, since 2002, the number of vehicles per household has exceeded the number of drivers per household.

Labor Force

Base and Future Year Data: The OKI labor force is a function of the population as determined by a labor force participation ratio (the number of employed persons in the labor force per persons 16 and over). Household data for base year 2005 originates with the 2000 Census of Population and Housing. Utilizing

the geographic information system ArcMap, household data at the zonal level for 2000 was derived from the area proportion allocation of block group level employed labor force. The labor force projections for 2005, 2010, 2020 and 2030 were based on the most recent projections of national labor force participation rates by age and sex cohorts from the U.S. Department of Labor, Bureau of Labor Statistics for each of those years. These rates were then applied to the projected county age/sex cohorts and adjusted to eliminate the unemployed to arrive at a county employed labor force control total. Employed labor force at the zonal level is calculated by multiplying the labor force participation rate by the zonal population. The labor force participation rate is adjusted so that, in each county, the sum of the zonal labor force counts equals the control total.

Employment

Base Year Data: Quarterly Census of Employment and Wages (QCEW or ES202) data for 2005 was utilized as the primary tool to calculate employment at the zonal level. Individual business records containing physical location, number of employees and SIC code were geocoded through ArcMap and aggregated to the TAZ level. This data set was supplemented by other sources of data to complete the commuting employment picture in the OKI region. Each zone's employment was divided according to the SIC code into three classes (retail, office, industrial) based upon the potential for generating trips.

Future Year Data: For future year employment projection, calculation was first made of the employment at the regional level. At the regional level, employment is a calculation of the region's employed labor force minus workers who live in the region but commute out to work, plus workers who live outside the region but commute in to work. The regional total was disaggregated first to the county level based on historic trends and expected changes in the county's share of the region's employment and then to the TAZ level. Disaggregation to TAZs was determined by historical trends, existing and future land use, topography, flood plain information, availability of land, local knowledge and other factors.

Area Type

Base and Future Year Data: For each analysis year, each TAZ is assigned an area type designation as CBD, Urban, Suburban or Rural based on population and employment densities.

Model Calibration

OKI's Travel Demand Model has been validated to observed traffic volumes for the model base year 2005. The modeling network encompasses the entire ozone nonattainment area with the exception of Clinton County, Ohio. The modeling network also includes Greene, Miami and Montgomery counties in Ohio and the remainder of Dearborn County Indiana. The difference between estimated vehicle miles traveled (VMT) and 2005 observed VMT is less than 1%. A highway screenline analysis compares the screenline observed and simulated traffic volume discrepancies with the ODOT standard of maximum desirable deviation. The comparison shows that the model performs at a satisfactory level and all the errors were under the ODOT curve. Further information can be found in OKI's 2007 report, "*OKI/MVRPC Travel Demand Model Methodology/ Validation Report*". For the calibration, OKI used over 3000 traffic counts collected through 2006 by the Ohio Department of Transportation (ODOT), the Kentucky

Transportation Cabinet, many county and local governments, transportation engineering consultants, and OKI. These traffic counts cover nearly 50% percent of the links in the OKI portion of the modeling network. The methodology provides consistency with past emission inventory and conformity analysis work performed by OKI.

Local Inputs and Post-Model Processing

OKI incorporates a variety of sources of local data to both improve and confirm the accuracy of VMT, as well as other travel-related parameters. Free flow speeds used on the highway and transit networks are based on travel time studies performed locally. The OKI post-processing program, IMPACT, uses the loaded highway network to generate VMT by hour, VMT by speed distribution and VMT by facility type. These tables are then included as input into MOVES. Two separate sets of VMT tables are generated: one for the four Ohio counties plus Dearborn County Indiana, and a second for the three Kentucky counties. The VMT by hour tables utilize hourly traffic distribution and directional split factors for different roadway types as developed by OKI. The main source of the data was the permanent traffic counting stations located throughout the OKI region for the years of 1998-2002. This data was supplemented with data collected at coverage count stations (locations with counts taken on only one-two days). The stations were classified by area type: urban and rural, and functional classification: freeway, arterial and collector. Speeds representing various "loaded" conditions (with traffic volumes) are estimated using techniques from the 1997 Highway Capacity Manual. This permits the estimation of speeds as conditions vary from hour to hour on the different facility types throughout the region. The IMPACT program performs the appropriate summation by area and roadway type as well as regional totals. OKI has also developed seasonal conversion factors to adjust traffic volumes to summer conditions. The factors were derived from local data collected at permanent traffic counting stations during 1994-1997 utilizing the average daily traffic monthly conversion factors for June, July and August. Further information on OKI's IMPACT program is documented in the report, *"Travel Demand Model Summary Reporting and Impact Summary Reporting: OKI/MVRPC Travel Demand Model User's Guide", OKI 2003.*

APPENDIX

OKI Technical Documentation for Using EPA MOVES to Develop MOBILE Source Emissions

August 2010

1. Using MOVES

To determine specific emission profiles and inventory, user has to define the input data like area, time span, type of vehicles, road types, fuel types, emission producing processes etc. These data are stored in an XML file which is called Runspec [sic]. Using graphical user interface user can modify all these attributes of Runspec [sic]. In the following sections, how input data is entered and modified is explained. All these input options are found in the navigation panel of Graphical User Interface of MOVES software.

1.1 Description

This input tells about the specifications of the Runspec [sic] and it is useful to distinguish between the Runspecs [sic]. We can also explain the brief overview of the particular Runspec [sic]. In all of our current Runspecs [sic], we have details such as analysis years, area and pollutants analyzed.

1.2 Scale

In this option, we need to specify about the Domain/Scale and Calculation type. The Domain specifies the level of default data we need to use for analysis and also the scale of the analysis. We have considered the County scale for Ohio Custom Domain and the calculation type we have used is “Emission Rates”.

1.3 Time Spans

This input panel has different time-related input data like time aggregation level, year of analysis, month of analysis, whether analysis day is Weekday or Weekend, and hours of analysis. In all of our runs, time aggregation level is considered as hour, which is the most disaggregated level possible in MOVES and it is also specified in the technical guidance† for all SIP runs. We have used different years of analysis (i.e. 2005, 2008, 2011, 2015, 2018, and 2021). We have used two different months, July and April. Ozone season daily analysis is done using July temperatures. Annual analysis uses one 24-hour set of average annual temperatures. The annual average minimum temperature, maximum temperature and humidity values for each hour were calculated and assigned the April month ID.

1.4 Geographic Bounds

In this input type, we need to specify about region of analysis (eg. Nation, State, Custom Domain). We have created a separate input database through combining four Ohio counties namely, Hamilton, Butler, Clermont and Warren. Upon selecting the custom domain, MOVES will consider this region as separate Generic County. The state ID is fixed as 99 and we have assigned an arbitrary CountyID 390 for Ohio to distinguish between default county codes. User also need to provide a fraction geographic phase in area, in this case we do not have any phase

in area fraction and we also provided average barometric pressure to identify whether it is low altitude area or high altitude area (the barometric pressures are averages of all constituent counties). Since we do not have I/M program in the region the refueling program adjustment fraction and refueling spill program adjustment fractions are assigned as 0.00. In this input panel we also need to specify the Domain Input Databases. For all of our runs we have defined different input databases for each year.

1.5 Vehicles/Equipment

In MOVES [sic], user also needs to provide the different type of vehicles considered for analysis in the region. MOVES [sic] provide us with 13 different types of vehicles or equipment and four different fuel types and we need to select appropriate fuel and vehicle combinations. In MOVES [sic] vehicle types are called SourceUseTypes [sic]. We have considered all possible types of fuel/vehicle type combinations.

1.6 Road Type

Next input panel is about type of roadways in the region. There are five types of road types available in MOVES, since OKI travel demand model could not predict the VMT in parking lots (off network) only four road types are considered. These road types are relatively simple and are based on area type, whether it is urban or rural. All expressways and freeways are considered as restricted roadways and all other road types are considered as unrestricted roadways.

1.7 Pollutants and Processes

There are different pollutants and corresponding processes are available in MOVES. A separate panel is available for selecting different pollutants and processes. In these particular set of runs, total PM2.5 emissions are selected with an addition of sulfur dioxide. To perform calculation of PM2.5 it is also required to select Total energy consumption. In addition to PM2.5, Oxides of Nitrogen are also selected.

1.8 Miscellaneous

Further, if we have information about future or present Alternative Vehicle Fuels & Technologies, on-road retrofit and rate of progress information that can be given as input to the Runspec [sic]. If we do not specify future Alternative Vehicle Fuel & Technologies, MOVES [sic] is going to assume default alternative fuels. So, we have modified default AVFT through importing new AVFT strategy file which includes there would not be any change in transit bus fuels. MOVES [sic] also provide us the options whether we would like to save the MOVESactivityoutput [sic] and MOVESOutput [sic] databases or not.

Table 1 : Alternative Vehicle and Fueling Technology used in all Runspecs [sic]

sourceTypeID	modelYearID	fuelTypeID	engTechID	fuelEngFraction
42	1960	2	1	1
42	1961	2	1	1
42	1962	2	1	1
42	1963	2	1	1
42	1964	2	1	1
42	1965	2	1	1
42	1966	2	1	1
42	1967	2	1	1
42	1968	2	1	1
42	1969	2	1	1
42	1970	2	1	1
42	1971	2	1	1
42	1972	2	1	1
42	1973	2	1	1
42	1974	2	1	1
42	1975	2	1	1
42	1976	2	1	1
42	1977	2	1	1
42	1978	2	1	1
42	1979	2	1	1
42	1980	2	1	1
42	1981	2	1	1
42	1982	2	1	1
42	1983	2	1	1
42	1984	2	1	1
42	1985	2	1	1
42	1986	2	1	1
42	1987	2	1	1
42	1988	2	1	1
42	1989	2	1	1
42	1990	2	1	1
42	1991	2	1	1
42	1992	2	1	1
42	1993	2	1	1
42	1994	2	1	1
42	1995	2	1	1
42	1996	2	1	1
42	1997	2	1	1
42	1998	2	1	1
42	1999	2	1	1
42	2000	2	1	1
42	2001	2	1	1
42	2002	2	1	1
42	2003	2	1	1
42	2004	2	1	1
42	2005	2	1	1

42	2006	2	1	1
42	2007	2	1	1
42	2008	2	1	1
42	2009	2	1	1
42	2010	2	1	1
42	2011	2	1	1
42	2012	2	1	1
42	2013	2	1	1
42	2014	2	1	1
42	2015	2	1	1
42	2016	2	1	1
42	2017	2	1	1
42	2018	2	1	1
42	2019	2	1	1
42	2020	2	1	1
42	2021	2	1	1
42	2022	2	1	1
42	2023	2	1	1
42	2024	2	1	1
42	2025	2	1	1
42	2026	2	1	1
42	2027	2	1	1
42	2028	2	1	1
42	2029	2	1	1
42	2030	2	1	1
42	2031	2	1	1
42	2032	2	1	1
42	2033	2	1	1
42	2034	2	1	1
42	2035	2	1	1
42	2036	2	1	1
42	2037	2	1	1
42	2038	2	1	1
42	2039	2	1	1
42	2040	2	1	1
42	2041	2	1	1
42	2042	2	1	1
42	2043	2	1	1
42	2044	2	1	1
42	2045	2	1	1
42	2046	2	1	1
42	2047	2	1	1
42	2048	2	1	1
42	2049	2	1	1
42	2050	2	1	1

1.9 Output

In MOVES we need to specify the output database and need to create new database for each new Runspec [sic]. We also have options like specifying the units for emission rates and energy consumption. These options are available in the General Output panel. There is one more option available within the output which is called output emissions detail, which provides user different options for data aggregation.

2. Data Importers

In order to enter local data into Runspec [sic], we need to use pre processing option in the MOVES. We can select either Data Importer or County Importer for Custom Domain option. These Importers convert the data in excel format to MySQL tables. This is the preferred input format of MOVES software.

2.1 Meteorology Data Importer

In this type of Importer, meteorology data is imported a MOVES input format. This dataset has different data items like month ID, Zone ID, hour ID, Temperature and Relative Humidity. For OKI region and Ohio portion runs we have used temperature data obtained from the Kentucky Division for Air Quality (KDAQ). Even though ODOT has provided the temperature data (collected from local airports), KDAQ data appeared to be more applicable. In the data set, April Meteorology data is replaced with annual average temperatures and relative humidity.

Table 2 : Meteorology data obtained from KDAQ

monthID	zoneID	hourID	temperature	relHumidity
4	993900	1	47.5	72.9
4	993900	2	46.4	75.8
4	993900	3	45.5	77.9
4	993900	4	44.8	79.4
4	993900	5	44.3	80.7
4	993900	6	43.7	82.1
4	993900	7	43.2	83.3
4	993900	8	43.6	82.3
4	993900	9	46.1	76.4
4	993900	10	50.1	67.0
4	993900	11	54.2	57.8
4	993900	12	57.7	50.9
4	993900	13	60.8	45.7
4	993900	14	62.5	43.1

4	993900	15	63.1	42.2
4	993900	16	63.2	42.0
4	993900	17	62.8	42.6
4	993900	18	61.7	44.3
4	993900	19	59.7	47.6
4	993900	20	57.1	52.2
4	993900	21	54.5	57.2
4	993900	22	52.2	62.1
4	993900	23	50.6	65.9
4	993900	24	49.1	69.4
7	993900	1	69.3	69.5
7	993900	2	68.1	72.4
7	993900	3	67.1	74.8
7	993900	4	66.4	76.6
7	993900	5	65.9	78
7	993900	6	65.3	79.7
7	993900	7	64.8	81.1
7	993900	8	65.2	79.9
7	993900	9	67.8	73.1
7	993900	10	72	63.4
7	993900	11	76.2	55
7	993900	12	79.8	48.8
7	993900	13	83	44
7	993900	14	84.7	41.6
7	993900	15	85.3	40.8
7	993900	16	85.5	40.6
7	993900	17	85.1	41.2
7	993900	18	83.9	42.8
7	993900	19	81.8	45.8
7	993900	20	79.1	49.9
7	993900	21	76.4	54.6
7	993900	22	74.1	59
7	993900	23	72.5	62.3
7	993900	24	70.8	65.9

2.2 Source Type Population Importer

This importer imports vehicle type, and registered vehicle population in the region into MOVES input databases. ODOT has provided us with the registered vehicle population in each county in the region for 13 MOVES vehicle types. KYTC has provided registered vehicle population by county for 6 HPMS vehicle types. The KYTC data was converted to the 13 MOVES vehicle types based on the Ohio distribution. Same vehicle population was used for all analysis years. As per suggestions made by FHWA and KYTC, the Source Type Population has been forecasted for future years with +0.8 % per year. Similarly, the Source Type Populations has been estimated for past years. The MOVES default source type population for intercity bus, refuse trucks, motor homes and combination trucks was used. In addition, MOVES default source type

population for passenger trucks and light commercial trucks was used for Kentucky. The MOVES default source type population was acquired from the MOVES activity output tables from county-level inventory runs.

Table3 : Source Type Population for Ohio Custom Domain (2008)

yearID	sourceTypeID	sourceTypePopulation
2008	11	68559
2008	21	1191067
2008	31	482420
2008	32	15817
2008	41	454
2008	42	81
2008	43	3651
2008	51	409
2008	52	366
2008	53	361
2008	54	4888
2008	61	4839
2008	62	5548

Table 4: Kentucky Source Type population (acquired from KYTC)

yearID	sourceTypeID	sourceTypePopulation
2008	11	7975
2008	21	197009
2008	31	120518
2008	32	40263
2008	41	127
2008	42	21
2008	43	977
2008	51	115
2008	52	761
2008	53	751
2008	54	1379
2008	61	1580
2008	62	1811

2.3 Age Distribution Importer

For emission calculation the MOVES need vehicle Age Distribution by Source Type. Vehicle Age Distribution is divided into 30 years based on vehicle model years. For each vehicle type, the distribution sum adds up to one. ODOT has obtained vehicle registration data from the Bureau of Motor Vehicles for all the counties in Ohio and processed them to convert into MOVES Age Distribution for 13 vehicle types. We have used the same Age Distribution for all year runs. All

the vehicles older than 30 years are considered as 30-years old. Same age distribution is used for all analysis years. KYTC also provided similar information, but for the 6 HPMS types only. For Kentucky, identical age distributions are used within each HPMS vehicle type.

Table 5 : Ohio Custom Domain Age distribution

Source TypeID	yearID	ageID	ageFraction
11	2008	0	0.0019
11	2008	1	0.0191
11	2008	2	0.0531
11	2008	3	0.0688
11	2008	4	0.0773
11	2008	5	0.0737
11	2008	6	0.0611
11	2008	7	0.0780
11	2008	8	0.0636
11	2008	9	0.0537
11	2008	10	0.0435
11	2008	11	0.0359
11	2008	12	0.0282
11	2008	13	0.0230
11	2008	14	0.0220
11	2008	15	0.0183
11	2008	16	0.0160
11	2008	17	0.0146
11	2008	18	0.0097
11	2008	19	0.0080
11	2008	20	0.0072
11	2008	21	0.0086
11	2008	22	0.0084
11	2008	23	0.0121
11	2008	24	0.0171
11	2008	25	0.0179
11	2008	26	0.0137
11	2008	27	0.0171
11	2008	28	0.0249
11	2008	29	0.0172
11	2008	30	0.0862
21	2008	0	0.0121
21	2008	1	0.0331
21	2008	2	0.0440
21	2008	3	0.0528
21	2008	4	0.0534
21	2008	5	0.0566
21	2008	6	0.0570
21	2008	7	0.0592
21	2008	8	0.0591
21	2008	9	0.0542
21	2008	10	0.0590
21	2008	11	0.0568
21	2008	12	0.0507
21	2008	13	0.0499
21	2008	14	0.0438
21	2008	15	0.0453
21	2008	16	0.0368
21	2008	17	0.0308
21	2008	18	0.0261
21	2008	19	0.0207
21	2008	20	0.0165
21	2008	21	0.0132
21	2008	22	0.0095
21	2008	23	0.0073
21	2008	24	0.0059
21	2008	25	0.0043
21	2008	26	0.0033
21	2008	27	0.0017
21	2008	28	0.0011
21	2008	29	0.0010
21	2008	30	0.0346
31	2008	0	0.0103
31	2008	1	0.0279
31	2008	2	0.0502
31	2008	3	0.0570
31	2008	4	0.0659
31	2008	5	0.0806
31	2008	6	0.0796
31	2008	7	0.0733
31	2008	8	0.0727
31	2008	9	0.0599
31	2008	10	0.0625
31	2008	11	0.0603
31	2008	12	0.0516
31	2008	13	0.0432
31	2008	14	0.0380
31	2008	15	0.0386
31	2008	16	0.0302
31	2008	17	0.0260
31	2008	18	0.0165
31	2008	19	0.0125
31	2008	20	0.0093

31	2008	21	0.0084
31	2008	22	0.0067
31	2008	23	0.0051
31	2008	24	0.0037
31	2008	25	0.0025
31	2008	26	0.0017
31	2008	27	0.0009
31	2008	28	0.0004
31	2008	29	0.0002
31	2008	30	0.0041
32	2008	0	0.0178
32	2008	1	0.0459
32	2008	2	0.0871
32	2008	3	0.0699
32	2008	4	0.0707
32	2008	5	0.0357
32	2008	6	0.0355
32	2008	7	0.0369
32	2008	8	0.0366
32	2008	9	0.0407
32	2008	10	0.0491
32	2008	11	0.0547
32	2008	12	0.0427
32	2008	13	0.0413
32	2008	14	0.0383
32	2008	15	0.0602
32	2008	16	0.0476
32	2008	17	0.0381
32	2008	18	0.0304
32	2008	19	0.0181
32	2008	20	0.0212
32	2008	21	0.0184
32	2008	22	0.0135
32	2008	23	0.0134
32	2008	24	0.0095
32	2008	25	0.0070
32	2008	26	0.0054
32	2008	27	0.0021
32	2008	28	0.0014
32	2008	29	0.0008
32	2008	30	0.0100
41	2008	0	0.0000
41	2008	1	0.0309
41	2008	2	0.0884
41	2008	3	0.0890
41	2008	4	0.0768
41	2008	5	0.0746
41	2008	6	0.0967
41	2008	7	0.0635

41	2008	8	0.0486
41	2008	9	0.0801
41	2008	10	0.0751
41	2008	11	0.0624
41	2008	12	0.0254
41	2008	13	0.0271
41	2008	14	0.0188
41	2008	15	0.0193
41	2008	16	0.0133
41	2008	17	0.0177
41	2008	18	0.0094
41	2008	19	0.0177
41	2008	20	0.0171
41	2008	21	0.0099
41	2008	22	0.0039
41	2008	23	0.0055
41	2008	24	0.0061
41	2008	25	0.0011
41	2008	26	0.0033
41	2008	27	0.0033
41	2008	28	0.0028
41	2008	29	0.0017
41	2008	30	0.0105
42	2008	0	0.0000
42	2008	1	0.0366
42	2008	2	0.1098
42	2008	3	0.0366
42	2008	4	0.1585
42	2008	5	0.0366
42	2008	6	0.0610
42	2008	7	0.0610
42	2008	8	0.0244
42	2008	9	0.1098
42	2008	10	0.0366
42	2008	11	0.0976
42	2008	12	0.0366
42	2008	13	0.0244
42	2008	14	0.0244
42	2008	15	0.0122
42	2008	16	0.0244
42	2008	17	0.0244
42	2008	18	0.0366
42	2008	19	0.0000
42	2008	20	0.0000
42	2008	21	0.0122
42	2008	22	0.0000
42	2008	23	0.0000
42	2008	24	0.0000
42	2008	25	0.0000

42	2008	26	0.0122
42	2008	27	0.0000
42	2008	28	0.0000
42	2008	29	0.0122
42	2008	30	0.0122
43	2008	0	0.0905
43	2008	1	0.0302
43	2008	2	0.0549
43	2008	3	0.0467
43	2008	4	0.0592
43	2008	5	0.0723
43	2008	6	0.0481
43	2008	7	0.0334
43	2008	8	0.0668
43	2008	9	0.0647
43	2008	10	0.0842
43	2008	11	0.0864
43	2008	12	0.0473
43	2008	13	0.0500
43	2008	14	0.0242
43	2008	15	0.0185
43	2008	16	0.0106
43	2008	17	0.0228
43	2008	18	0.0109
43	2008	19	0.0130
43	2008	20	0.0125
43	2008	21	0.0092
43	2008	22	0.0062
43	2008	23	0.0079
43	2008	24	0.0090
43	2008	25	0.0035
43	2008	26	0.0030
43	2008	27	0.0011
43	2008	28	0.0027
43	2008	29	0.0016
43	2008	30	0.0087
51	2008	0	0.0054
51	2008	1	0.0488
51	2008	2	0.0623
51	2008	3	0.0705
51	2008	4	0.0867
51	2008	5	0.0434
51	2008	6	0.0434
51	2008	7	0.0542
51	2008	8	0.0542
51	2008	9	0.0759
51	2008	10	0.0217
51	2008	11	0.0407
51	2008	12	0.0786

51	2008	13	0.0542
51	2008	14	0.0515
51	2008	15	0.0678
51	2008	16	0.0325
51	2008	17	0.0081
51	2008	18	0.0163
51	2008	19	0.0027
51	2008	20	0.0081
51	2008	21	0.0000
51	2008	22	0.0027
51	2008	23	0.0027
51	2008	24	0.0136
51	2008	25	0.0000
51	2008	26	0.0000
51	2008	27	0.0000
51	2008	28	0.0027
51	2008	29	0.0000
51	2008	30	0.0515
52	2008	0	0.0054
52	2008	1	0.0488
52	2008	2	0.0623
52	2008	3	0.0705
52	2008	4	0.0867
52	2008	5	0.0434
52	2008	6	0.0434
52	2008	7	0.0542
52	2008	8	0.0542
52	2008	9	0.0759
52	2008	10	0.0217
52	2008	11	0.0407
52	2008	12	0.0786
52	2008	13	0.0542
52	2008	14	0.0515
52	2008	15	0.0678
52	2008	16	0.0325
52	2008	17	0.0081
52	2008	18	0.0163
52	2008	19	0.0027
52	2008	20	0.0081
52	2008	21	0.0000
52	2008	22	0.0027
52	2008	23	0.0027
52	2008	24	0.0136
52	2008	25	0.0000
52	2008	26	0.0000
52	2008	27	0.0000
52	2008	28	0.0027
52	2008	29	0.0000
52	2008	30	0.0515

53	2008	0	0.0000
53	2008	1	0.0062
53	2008	2	0.0373
53	2008	3	0.0093
53	2008	4	0.0280
53	2008	5	0.0342
53	2008	6	0.0186
53	2008	7	0.0186
53	2008	8	0.0124
53	2008	9	0.0155
53	2008	10	0.0217
53	2008	11	0.0373
53	2008	12	0.0093
53	2008	13	0.0311
53	2008	14	0.0217
53	2008	15	0.0373
53	2008	16	0.0217
53	2008	17	0.0342
53	2008	18	0.0124
53	2008	19	0.0186
53	2008	20	0.0248
53	2008	21	0.0373
53	2008	22	0.0186
53	2008	23	0.0248
53	2008	24	0.0062
53	2008	25	0.0373
53	2008	26	0.0155
53	2008	27	0.0186
53	2008	28	0.0217
53	2008	29	0.0186
53	2008	30	0.3509
54	2008	0	0.0077
54	2008	1	0.0170
54	2008	2	0.0377
54	2008	3	0.0424
54	2008	4	0.0471
54	2008	5	0.0579
54	2008	6	0.0552
54	2008	7	0.0485
54	2008	8	0.0406
54	2008	9	0.0439
54	2008	10	0.0505
54	2008	11	0.0539
54	2008	12	0.0435
54	2008	13	0.0360
54	2008	14	0.0348
54	2008	15	0.0375
54	2008	16	0.0303
54	2008	17	0.0231
54	2008	18	0.0196
54	2008	19	0.0150
54	2008	20	0.0183
54	2008	21	0.0208
54	2008	22	0.0218
54	2008	23	0.0217
54	2008	24	0.0186
54	2008	25	0.0173
54	2008	26	0.0163
54	2008	27	0.0118
54	2008	28	0.0084
54	2008	29	0.0059
54	2008	30	0.0968
61	2008	0	0.0030
61	2008	1	0.0167
61	2008	2	0.0334
61	2008	3	0.0393
61	2008	4	0.0506
61	2008	5	0.0530
61	2008	6	0.0620
61	2008	7	0.0625
61	2008	8	0.0562
61	2008	9	0.0551
61	2008	10	0.0595
61	2008	11	0.0569
61	2008	12	0.0458
61	2008	13	0.0493
61	2008	14	0.0380
61	2008	15	0.0435
61	2008	16	0.0425
61	2008	17	0.0312
61	2008	18	0.0262
61	2008	19	0.0235
61	2008	20	0.0201
61	2008	21	0.0225
61	2008	22	0.0212
61	2008	23	0.0141
61	2008	24	0.0137
61	2008	25	0.0096
61	2008	26	0.0069
61	2008	27	0.0039
61	2008	28	0.0030
61	2008	29	0.0027
61	2008	30	0.0343
62	2008	0	0.0078
62	2008	1	0.0232
62	2008	2	0.0307
62	2008	3	0.0907
62	2008	4	0.0721

62	2008	5	0.0808
62	2008	6	0.0564
62	2008	7	0.0520
62	2008	8	0.0360
62	2008	9	0.0552
62	2008	10	0.1019
62	2008	11	0.0813
62	2008	12	0.0603
62	2008	13	0.0425
62	2008	14	0.0439
62	2008	15	0.0442
62	2008	16	0.0273
62	2008	17	0.0202
62	2008	18	0.0122
62	2008	19	0.0101
62	2008	20	0.0103
62	2008	21	0.0080
62	2008	22	0.0079
62	2008	23	0.0058
62	2008	24	0.0050
62	2008	25	0.0036
62	2008	26	0.0038
62	2008	27	0.0001
62	2008	28	0.0012
62	2008	29	0.0010
62	2008	30	0.0046

Table 6 : Kentucky Custom Domain Age distribution

Source TypeID	yearID	ageID	ageFraction
11	2008	0	0.0020
11	2008	1	0.0323
11	2008	2	0.0606
11	2008	3	0.0826
11	2008	4	0.0831
11	2008	5	0.0774
11	2008	6	0.0667
11	2008	7	0.0830
11	2008	8	0.0650
11	2008	9	0.0495
11	2008	10	0.0424
11	2008	11	0.0345
11	2008	12	0.0287
11	2008	13	0.0214
11	2008	14	0.0240
11	2008	15	0.0208
11	2008	16	0.0138
11	2008	17	0.0129
11	2008	18	0.0092
11	2008	19	0.0051
11	2008	20	0.0052
11	2008	21	0.0058
11	2008	22	0.0078
11	2008	23	0.0108
11	2008	24	0.0153
11	2008	25	0.0168
11	2008	26	0.0124
11	2008	27	0.0160
11	2008	28	0.0228
11	2008	29	0.0152
11	2008	30	0.0568
21	2008	0	0.0118
21	2008	1	0.0665
21	2008	2	0.0596
21	2008	3	0.0642
21	2008	4	0.0611
21	2008	5	0.0705
21	2008	6	0.0694
21	2008	7	0.0699
21	2008	8	0.0719
21	2008	9	0.0619
21	2008	10	0.0633
21	2008	11	0.0591
21	2008	12	0.0490
21	2008	13	0.0442
21	2008	14	0.0348
21	2008	15	0.0318
21	2008	16	0.0241
21	2008	17	0.0191
21	2008	18	0.0142
21	2008	19	0.0111
21	2008	20	0.0088
21	2008	21	0.0066
21	2008	22	0.0049
21	2008	23	0.0039
21	2008	24	0.0028
21	2008	25	0.0024

21	2008	26	0.0018
21	2008	27	0.0009
21	2008	28	0.0005
21	2008	29	0.0005
21	2008	30	0.0094
31	2008	0	0.0000
31	2008	1	0.0000
31	2008	2	0.0000
31	2008	3	0.0000
31	2008	4	0.0238
31	2008	5	0.0119
31	2008	6	0.0119
31	2008	7	0.0119
31	2008	8	0.0119
31	2008	9	0.0000
31	2008	10	0.0238
31	2008	11	0.0357
31	2008	12	0.0119
31	2008	13	0.0952
31	2008	14	0.0833
31	2008	15	0.0595
31	2008	16	0.1071
31	2008	17	0.0357
31	2008	18	0.0357
31	2008	19	0.0357
31	2008	20	0.0119
31	2008	21	0.0476
31	2008	22	0.0238
31	2008	23	0.0119
31	2008	24	0.0119
31	2008	25	0.0595
31	2008	26	0.0357
31	2008	27	0.0000
31	2008	28	0.0238
31	2008	29	0.0238
31	2008	30	0.1548
32	2008	0	0.0000
32	2008	1	0.0000
32	2008	2	0.0000
32	2008	3	0.0000
32	2008	4	0.0238
32	2008	5	0.0119
32	2008	6	0.0119
32	2008	7	0.0119
32	2008	8	0.0119
32	2008	9	0.0000
32	2008	10	0.0238
32	2008	11	0.0357
32	2008	12	0.0119
32	2008	13	0.0952
32	2008	14	0.0833
32	2008	15	0.0595
32	2008	16	0.1071
32	2008	17	0.0357
32	2008	18	0.0357
32	2008	19	0.0357
32	2008	20	0.0119
32	2008	21	0.0476
32	2008	22	0.0238
32	2008	23	0.0119
32	2008	24	0.0119
32	2008	25	0.0595
32	2008	26	0.0357
32	2008	27	0.0000
32	2008	28	0.0238
32	2008	29	0.0238
32	2008	30	0.1548
41	2008	0	0.0455
41	2008	1	0.1136
41	2008	2	0.0000
41	2008	3	0.0114
41	2008	4	0.0227
41	2008	5	0.0000
41	2008	6	0.0000
41	2008	7	0.0114
41	2008	8	0.0114
41	2008	9	0.0227
41	2008	10	0.0114
41	2008	11	0.0568
41	2008	12	0.1250
41	2008	13	0.0227
41	2008	14	0.0000
41	2008	15	0.0341
41	2008	16	0.0341
41	2008	17	0.0682
41	2008	18	0.0455
41	2008	19	0.0909
41	2008	20	0.0568
41	2008	21	0.0455
41	2008	22	0.0341
41	2008	23	0.0455
41	2008	24	0.0227
41	2008	25	0.0227
41	2008	26	0.0114
41	2008	27	0.0000
41	2008	28	0.0227
41	2008	29	0.0000
41	2008	30	0.0114

42	2008	0	0.0455
42	2008	1	0.1136
42	2008	2	0.0000
42	2008	3	0.0114
42	2008	4	0.0227
42	2008	5	0.0000
42	2008	6	0.0000
42	2008	7	0.0114
42	2008	8	0.0114
42	2008	9	0.0227
42	2008	10	0.0114
42	2008	11	0.0568
42	2008	12	0.1250
42	2008	13	0.0227
42	2008	14	0.0000
42	2008	15	0.0341
42	2008	16	0.0341
42	2008	17	0.0682
42	2008	18	0.0455
42	2008	19	0.0909
42	2008	20	0.0568
42	2008	21	0.0455
42	2008	22	0.0341
42	2008	23	0.0455
42	2008	24	0.0227
42	2008	25	0.0227
42	2008	26	0.0114
42	2008	27	0.0000
42	2008	28	0.0227
42	2008	29	0.0000
42	2008	30	0.0114
43	2008	0	0.0455
43	2008	1	0.1136
43	2008	2	0.0000
43	2008	3	0.0114
43	2008	4	0.0227
43	2008	5	0.0000
43	2008	6	0.0000
43	2008	7	0.0114
43	2008	8	0.0114
43	2008	9	0.0227
43	2008	10	0.0114
43	2008	11	0.0568
43	2008	12	0.1250
43	2008	13	0.0227
43	2008	14	0.0000
43	2008	15	0.0341
43	2008	16	0.0341
43	2008	17	0.0682
43	2008	18	0.0455
43	2008	19	0.0909
43	2008	20	0.0568
43	2008	21	0.0455
43	2008	22	0.0341
43	2008	23	0.0455
43	2008	24	0.0227
43	2008	25	0.0227
43	2008	26	0.0114
43	2008	27	0.0000
43	2008	28	0.0227
43	2008	29	0.0000
43	2008	30	0.0114
51	2008	0	0.0025
51	2008	1	0.0200
51	2008	2	0.0386
51	2008	3	0.0436
51	2008	4	0.0495
51	2008	5	0.0579
51	2008	6	0.0667
51	2008	7	0.0698
51	2008	8	0.0620
51	2008	9	0.0611
51	2008	10	0.0675
51	2008	11	0.0619
51	2008	12	0.0508
51	2008	13	0.0529
51	2008	14	0.0397
51	2008	15	0.0397
51	2008	16	0.0375
51	2008	17	0.0276
51	2008	18	0.0204
51	2008	19	0.0184
51	2008	20	0.0158
51	2008	21	0.0174
51	2008	22	0.0152
51	2008	23	0.0108
51	2008	24	0.0108
51	2008	25	0.0071
51	2008	26	0.0052
51	2008	27	0.0031
51	2008	28	0.0021
51	2008	29	0.0021
51	2008	30	0.0220
52	2008	0	0.0025
52	2008	1	0.0200
52	2008	2	0.0386
52	2008	3	0.0436
52	2008	4	0.0495

52	2008	5	0.0579
52	2008	6	0.0667
52	2008	7	0.0698
52	2008	8	0.0620
52	2008	9	0.0611
52	2008	10	0.0675
52	2008	11	0.0619
52	2008	12	0.0508
52	2008	13	0.0529
52	2008	14	0.0397
52	2008	15	0.0397
52	2008	16	0.0375
52	2008	17	0.0276
52	2008	18	0.0204
52	2008	19	0.0184
52	2008	20	0.0158
52	2008	21	0.0174
52	2008	22	0.0152
52	2008	23	0.0108
52	2008	24	0.0108
52	2008	25	0.0071
52	2008	26	0.0052
52	2008	27	0.0031
52	2008	28	0.0021
52	2008	29	0.0021
52	2008	30	0.0220
53	2008	0	0.0025
53	2008	1	0.0200
53	2008	2	0.0386
53	2008	3	0.0436
53	2008	4	0.0495
53	2008	5	0.0579
53	2008	6	0.0667
53	2008	7	0.0698
53	2008	8	0.0620
53	2008	9	0.0611
53	2008	10	0.0675
53	2008	11	0.0619
53	2008	12	0.0508
53	2008	13	0.0529
53	2008	14	0.0397
53	2008	15	0.0397
53	2008	16	0.0375
53	2008	17	0.0276
53	2008	18	0.0204
53	2008	19	0.0184
53	2008	20	0.0158
53	2008	21	0.0174
53	2008	22	0.0152
53	2008	23	0.0108
53	2008	24	0.0108
53	2008	25	0.0071
53	2008	26	0.0052
53	2008	27	0.0031
53	2008	28	0.0021
53	2008	29	0.0021
53	2008	30	0.0220
54	2008	0	0.0025
54	2008	1	0.0200
54	2008	2	0.0386
54	2008	3	0.0436
54	2008	4	0.0495
54	2008	5	0.0579
54	2008	6	0.0667
54	2008	7	0.0698
54	2008	8	0.0620
54	2008	9	0.0611
54	2008	10	0.0675
54	2008	11	0.0619
54	2008	12	0.0508
54	2008	13	0.0529
54	2008	14	0.0397
54	2008	15	0.0397
54	2008	16	0.0375
54	2008	17	0.0276
54	2008	18	0.0204
54	2008	19	0.0184
54	2008	20	0.0158
54	2008	21	0.0174
54	2008	22	0.0152
54	2008	23	0.0108
54	2008	24	0.0108
54	2008	25	0.0071
54	2008	26	0.0052
54	2008	27	0.0031
54	2008	28	0.0021
54	2008	29	0.0021
54	2008	30	0.0220
61	2008	0	0.0000
61	2008	1	0.0064
61	2008	2	0.0295
61	2008	3	0.0205
61	2008	4	0.0321
61	2008	5	0.0346
61	2008	6	0.0423
61	2008	7	0.0308
61	2008	8	0.0269
61	2008	9	0.0179

61	2008	10	0.0462
61	2008	11	0.0410
61	2008	12	0.0359
61	2008	13	0.0513
61	2008	14	0.0333
61	2008	15	0.0359
61	2008	16	0.0423
61	2008	17	0.0269
61	2008	18	0.0295
61	2008	19	0.0231
61	2008	20	0.0385
61	2008	21	0.0397
61	2008	22	0.0333
61	2008	23	0.0346
61	2008	24	0.0295
61	2008	25	0.0192
61	2008	26	0.0346
61	2008	27	0.0128
61	2008	28	0.0141
61	2008	29	0.0128
61	2008	30	0.1244
62	2008	0	0.0000
62	2008	1	0.0064
62	2008	2	0.0295
62	2008	3	0.0205
62	2008	4	0.0321
62	2008	5	0.0346
62	2008	6	0.0423
62	2008	7	0.0308
62	2008	8	0.0269
62	2008	9	0.0179
62	2008	10	0.0462
62	2008	11	0.0410
62	2008	12	0.0359
62	2008	13	0.0513
62	2008	14	0.0333
62	2008	15	0.0359
62	2008	16	0.0423
62	2008	17	0.0269
62	2008	18	0.0295
62	2008	19	0.0231
62	2008	20	0.0385
62	2008	21	0.0397
62	2008	22	0.0333
62	2008	23	0.0346
62	2008	24	0.0295
62	2008	25	0.0192
62	2008	26	0.0346
62	2008	27	0.0128
62	2008	28	0.0141
62	2008	29	0.0128
62	2008	30	0.1244

2.4 Vehicle Type VMT and VMT Fractions

This option is useful to import the annual VMT by source type into MOVES format. It has input option as HPMS Base Year VMT, for which we can either use HPMS data or the Travel Demand Model output. We have used annual VMT calculated from the OKI Regional Travel Demand Model. There are options like the Month VMT fraction, Day VMT fraction and Hour VMT fraction, which are useful for calculating emissions for different time periods. We have used default Monthly VMT distribution factors provided in the VMT Converter provided by EPA. Hourly distribution factors are developed from traffic count data collected in the region and the same set of Hourly Distribution Factors are used for all vehicle types and road types. OKI model could only predict VMT of two different vehicle types' autos and trucks. So, we have distributed total Annual VMT based on vehicle population in the region.

Table 7 : Annual VMT for Ohio Custom Domain from OKI travel demand model for 2005

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2005	67065022	0
20	2005	7405961237	0
30	2005	4943917030	0
40	2005	24512225	0
50	2005	334351024	0
60	2005	567810955	0

Table 8 :Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2005

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2005	16658465	0
20	2005	1815341688	0
30	2005	1209494070	0
40	2005	5968488	0
50	2005	82065068	0
60	2005	160708291	0

Table 9: Annual VMT for Ohio Custom Domain from OKI travel demand model for 2008

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	69438850	0
20	2008	7668102136	0
30	2008	5118911580	0
40	2008	25379858	0
50	2008	346185690	0
60	2008	587909153	0

Table 10 : Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2008

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	17342291	0
20	2008	1889861055	0
30	2008	1259143528	0
40	2008	6213493	0
50	2008	85433821	0
60	2008	167305330	0

Table 9: Annual VMT for Ohio Custom Domain from OKI travel demand model for 2011

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2008	69438850	0
20	2008	7668102136	0
30	2008	5118911580	0
40	2008	25379858	0
50	2008	346185689	0
60	2008	587909153	0

Table 11: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2011

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2011	18163152	0
20	2011	1979313603	0
30	2011	1318742406	0
40	2011	6507596	0
50	2011	89477649	0
60	2011	175224371	0

Table 12 :Annual VMT for Ohio Custom Domain from OKI travel demand model for 2015

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2015	73413634	0
20	2015	8107035747	0
30	2015	5411925719	0
40	2015	26832639	0
50	2015	366001875	0
60	2015	621561950	0

Table 13: Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2015

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2015	19903870	0
20	2015	2169006811	0
30	2015	1445127874	0

40	2015	7131270	0
50	2015	98052996	0
60	2015	192017502	0

Table 14:Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2018

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2018	76802311	0
20	2018	8481245879	0
30	2018	5661733109	0
40	2018	28071199	0
50	2018	382896041	0
60	2018	650252434	0

Table 13:Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2018

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2018	21077884	0
20	2018	2296944011	0
30	2018	1530367631	0
40	2018	7551902	0
50	2018	103836577	0
60	2018	203343507	0

Table 14 : Annual VMT for Ohio Custom Domain from OKI travel demand model for 2021

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2021	79128218	0
20	2021	8738094842	0
30	2021	5833194979	0
40	2021	28921317	0
50	2021	394491797	0
60	2021	669944902	0

Table 15 : Annual VMT for Kentucky Custom Domain from OKI travel demand model for 2021

HPMSVtypeID	yearID	HPMSBaseYearVMT	baseYearOffNetVMT
10	2021	21702396	0
20	2021	2364999583	0
30	2021	1575710506	0
40	2021	7775656	0
50	2021	106913124	0
60	2021	209368320	0

Table 16 : Default Monthly VMT Distribution(year 2008)

sourceTypeID	isLeapYear	monthID	monthVMTFraction
11	Y	1	0.072904
11	Y	2	0.072023
11	Y	3	0.081529
11	Y	4	0.082098
11	Y	5	0.087286
11	Y	6	0.088052
11	Y	7	0.092096
11	Y	8	0.093198
11	Y	9	0.08447
11	Y	10	0.086301
11	Y	11	0.080029
11	Y	12	0.080015
21	Y	1	0.072904
21	Y	2	0.072023
21	Y	3	0.081529
21	Y	4	0.082098
21	Y	5	0.087286
21	Y	6	0.088052
21	Y	7	0.092096
21	Y	8	0.093198
21	Y	9	0.08447
21	Y	10	0.086301
21	Y	11	0.080029
21	Y	12	0.080015
31	Y	1	0.072904
31	Y	2	0.072023

Table 17 : Default Daily VMT distribution (same for all Source Types and all years)

sourceTypeID	monthID	roadTypeID	dayID	dayVMTFraction
11	1	1	2	0.237635
11	1	1	5	0.762365
11	1	2	2	0.237635
11	1	2	5	0.762365
11	1	3	2	0.237635
11	1	3	5	0.762365
11	1	4	2	0.237635
11	1	4	5	0.762365
11	1	5	2	0.237635
11	1	5	5	0.762365

Table 18 : Hourly VMT Distribution from local data

sourceTypeID	roadTypeID	dayID	hourID	hourVMTFraction
11	1	2	1	0.021474
11	1	2	2	0.014443
11	1	2	3	0.010968
11	1	2	4	0.007495
11	1	2	5	0.006839
11	1	2	6	0.010359
11	1	2	7	0.01843
11	1	2	8	0.026812
11	1	2	9	0.036385
11	1	2	10	0.047541
11	1	2	11	0.057466
11	1	2	12	0.065079
11	1	2	13	0.071323
11	1	2	14	0.071492
11	1	2	15	0.071723
11	1	2	16	0.072006
11	1	2	17	0.071149
11	1	2	18	0.067887
11	1	2	19	0.061772
11	1	2	20	0.051688
11	1	2	21	0.042866
11	1	2	22	0.03803
11	1	2	23	0.032207
11	1	2	24	0.024568

2.5 Average Speed Distribution Importer

This importer allows the user to input average speed data specific to vehicle type, road type, and time of day/ type of day. The MOVES model defines 16 “speed bins” which describe the average driving speed on each road type. Unlike MOBILE 6.2 model, which uses VMT-based speed distribution, MOVES use fraction of driving time in each speed bin for each vehicle type, for each road type, and for each hour. Thus, for each combination of vehicle type, road type, and hour/day type, the fractions will add to one. We have used OKI travel model to calculate average speed distribution based on VHT. However, this input is ignored by MOVES when we are running emission rate runs† (See Table 27).

2.6 Road Type Distribution Importer

User supplied vehicle-miles-traveled data by road type is used as an input in this importer. OKI travel demand model can calculate the VMT distribution by functional class, which is further

processed to obtain road type VMT distribution. But, our model could not predict off network VMT, which is assumed as zero. However, this input is also ignored by MOVES when we are running Emission Rate runs † (see Table 26).

2.7 Ramp Fraction Importer

This option allows the user to modify the fraction of ramp driving time on selected road types. But, in the current version of MOVES model, there is no capability to model Emission Rates for Ramps. To circumvent this problem, FHWA has suggested a temporary solution. This solution discussed in the Section 3.

2.8 Fuel Formulation Importer and Fuel Supply Importer

Fuel formulation importer allows the user to select an existing fuel in the MOVES database and change its properties, or create a new fuel formulation with different fuel properties. But we have used only default fuels available in MOVES default database. Fuel supply importer allows the user to assign existing fuels to counties, months, and years, and the associated market share for each fuel. We have used default fuel supply from MOVES default database. And same type of fuel is used for Whole Custom Domain.

Table 19 : Fuel supply data for Ohio Custom Domain (same for all years)

countyID	fuelYearID	monthGroupID	fuelFormulationID	marketShare	marketShareCV
99390	2008	1	3982	1	
99390	2008	1	20011	1	
99390	2008	2	3982	1	
99390	2008	2	20011	1	
99390	2008	3	3982	1	
99390	2008	3	20011	1	
99390	2008	4	3982	1	
99390	2008	4	20011	1	
99390	2008	5	3982	1	
99390	2008	5	20011	1	
99390	2008	6	3982	1	
99390	2008	6	20011	1	
99390	2008	7	3982	1	
99390	2008	7	20011	1	
99390	2008	8	3982	1	
99390	2008	8	20011	1	
99390	2008	9	3982	1	
99390	2008	9	20011	1	
99390	2008	10	3982	1	
99390	2008	10	20011	1	
99390	2008	11	3982	1	
99390	2008	11	20011	1	

99390	2008	12	3982	1	
99390	2008	12	20011	1	

Table 20: Fuel supply data for Kentucky Custom Domain (same for all years)

countyID	fuelYearID	monthGroupID	fuelFormulationID	marketShare	marketShareCV
99210	2012	1	3982	1	
99210	2012	1	20011	1	
99210	2012	2	3982	1	
99210	2012	2	20011	1	
99210	2012	3	3982	1	
99210	2012	3	20011	1	
99210	2012	4	3982	1	
99210	2012	4	20011	1	
99210	2012	5	3982	1	
99210	2012	5	20011	1	
99210	2012	6	3982	1	
99210	2012	6	20011	1	
99210	2012	7	3982	1	
99210	2012	7	20011	1	
99210	2012	8	3982	1	
99210	2012	8	20011	1	
99210	2012	9	3982	1	
99210	2012	9	20011	1	
99210	2012	10	3982	1	
99210	2012	10	20011	1	
99210	2012	11	3982	1	
99210	2012	11	20011	1	
99210	2012	12	3982	1	
99210	2012	12	20011	1	

2.9 I/M Importer

The I/M Importer allows the user to import information describing the inspection and maintenance programs. In the default database there is an option, whether to use default I/M program or not. We choose no I/M program for all of the Runspecs[sic] in the whole region.

2.10 Zone Road Activity Importer

The Zone Road Activity Importer is used only if the Custom Domain option is chosen in the County Domain Manager. We have used value 1 for SHOallocfactor for each road type which means that all of the VMT input by the users is assigned to custom domain.

Table 21 : Kentucky Custom Domain Zone road activity data (same for all years)

zoneID	roadTypeID	SHOAllocFactor
992100	1	1
992100	2	1
992100	3	1
992100	4	1
992100	5	1

Table 22 : Ohio Custom Domain Zone road activity data (same for all years)

zoneID	roadTypeID	SHOAllocFactor
993900	1	1
993900	2	1
993900	3	1
993900	4	1
993900	5	1

3. Ramp Inventory Runs

As discussed earlier, current version of the MOVES model cannot calculate Emission Rates for Ramps. To deal with this problem, FHWA has suggested an approach. The steps involved in this method are: (a) Calculating Emission Inventory for Urban Restricted and Rural Restricted road types keeping Ramp fraction as 1 (b) Finding out total VMT of Urban Restricted and Rural Restricted road types using MOVESactivityoutput option (c) Calculation Emission Rates for Ramps through dividing Emission Inventory with VMT (d) Finally, using the Emission Rates in post processing for calculating regional Emission Inventory.

Table 23 :Ramp fraction Input

roadTypeID	rampFraction
2	1
4	1

4. Post-Processing of MOVES Output

4.1 Linking SQL tables to Microsoft Access

Microsoft Access 2007 was used for the post-processing. An ODBC connection with the MOVES output directory was established. Information on how to link or import SQL tables to Access can be found in the MOVES Users Guide.

4.2 Creating Emission Rate Lookup Tables

The ratepervehicle and rateperdistance SQL tables, one set for each state (Kentucky and Ohio) and analysis year, were imported into Access. Ohio emission rates are used for the nonattainment portion of Dearborn County Indiana. Rateperprofile output was not generated by MOVES because evaporative output was not selected (i.e. VOC). Tables were renamed with state and analysis year in the format OH_20xxrateperdistance. All rateperdistance tables were merged with a Union query. The SQL commands are shown in Figure 3.1. ratepervehicle tables were merged in the same manner.

Table 24 :Rateperdistance Union Query

```
SELECT *
FROM OH_2008rateperdistance
WHERE MOVESRunID = (select max (MOVESRunID) from OH_2008rateperdistance) AND
pollutantID = 3 Or MOVESRunID =  (select max (MOVESRunID) from
OH_2008rateperdistance) AND pollutantID=110 Or MOVESRunID =  (select max
(MOVESRunID) from OH_2008rateperdistance) AND pollutantID=116 Or MOVESRunID =
(select max (MOVESRunID) from OH_2008rateperdistance) AND pollutantID=117 Or
MOVESRunID = (select max (MOVESRunID) from OH_2008rateperdistance) AND
pollutantID = 31
UNION ALL select *
FROM OH_2011rateperdistance
WHERE ….. (repeated for each file)
```

"Rateperdistance_state" and "Ratepervehicle_state" tables were created from the union query output using a Make Table query. Emission rates for each process were summed by pollutant and a stateID field is created. The SQL commands for creating the "Rateperdistance_state" table are shown in Table 25. Unique index fields were identified for each of the two tables. Indexes facilitate more efficient data processing.

Table 25: Rateperdistance_State Query

```
SELECT Val(Mid([LinkID],3,2)) AS StateID, Union_rateperdistance_state.yearID,
Union_rateperdistance_state.monthID, Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.sourceTypeID,
Union_rateperdistance_state.roadTypeID,
Union_rateperdistance_state.avgSpeedBinID,
Union_rateperdistance_state.pollutantID,
Sum(Union_rateperdistance_state.ratePerDistance) AS SumOfratePerDistance INTO
rateperdistance_state
```

```
FROM Union_rateperdistance_state
GROUP BY Val(Mid([LinkID],3,2)), Union_rateperdistance_state.yearID,
Union_rateperdistance_state.monthID, Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.sourceTypeID,
Union_rateperdistance_state.roadTypeID,
Union_rateperdistance_state.avgSpeedBinID,
Union_rateperdistance_state.pollutantID
ORDER BY Union_rateperdistance_state.linkID,
Union_rateperdistance_state.hourID, Union_rateperdistance_state.pollutantID;
```

4.1 Creating a VMT Table by County

The VMT table includes Daily VMT by county by analysis year from the OKI Travel Demand Model (TDM). Summer factors and applied by functional class to create Summer VMT. Seasonal factors by functional class are contained in the report, "OKI Travel Demand Forecasting Model, Update of Hourly and Seasonal Factors as Used in Air Quality Impact Calculations", September 2001. Annual VMT is calculated by using EPA's VMT converter to grow daily VMT to annual VMT. In order to accommodate an error in MOVES 2010, all VMT values are exclusive of ramp VMT. Ramp VMT and emission are added in later in the process. In order to apply the emission rates, it is necessary to factor the county VMT by source type, hour, road type and speed bin.

Table 26 : VMT and Source Type Population by County and Year

County	Daily VMT	Summer VMT	Annual VMT	yearID	SourceType Population	stateID
Boone	3924117	4186006	1273226984	2005	129823	21
Boone	4076584	4355527	1350001557	2008	134028	21
Boone	4383716	4681593	1448879510	2011	136181	21
Boone	4950741	5276742	1628041303	2015	140590	21
Boone	5260102	5597287	1729595179	2018	143991	21
Boone	5478224	5826768	1800571708	2021	147476	21
Campbell	2286217	2437698	741790605	2005	86065	21
Campbell	2339542	2495174	774762729	2008	88853	21
Campbell	2421600	2582758	800372702	2011	90279	21
Campbell	2663159	2844504	875774499	2015	93204	21
Campbell	2771476	2958827	911300109	2018	95458	21
Campbell	2849127	3041704	936445364	2021	97768	21
Kenton	3927743	4182042	1274091658	2005	148193	21
Kenton	3927332	4185652	1300575265	2008	152992	21
Kenton	4049886	4327836	1338544021	2011	155451	21
Kenton	4341124	4614242	1427569992	2015	160484	21
Kenton	4629694	4880614	1522308203	2018	164368	21
Kenton	4715306	5006383	1549817345	2021	168343	21
Butler	578641	7804476	196737836	2005	24915	39

Butler	587582	8133554	199777880	2008	25722	39
Butler	605620	8454053	205910800	2011	26135	39
Butler	657778	8768598	223644400	2015	26982	39
Butler	684361	9232457	232682740	2018	27635	39
Butler	706828	9592567	240321520	2021	28303	39
Clermont	7452286	5391578	2469166037	2005	401759	39
Clermont	7745685	5599530	2598059212	2008	414771	39
Clermont	8050701	5841102	2693716250	2011	421434	39
Clermont	8361487	6035155	2792188144	2015	435082	39
Clermont	8806042	6314640	2940849935	2018	445608	39
Clermont	9150031	6562428	2966037449	2021	456389	39
Dearborn NA	5083331	599761	1684259908	2005	232380	39
Dearborn NA	5262489	613027	1765145113	2008	239906	39
Dearborn NA	5489545	631914	1836768820	2011	243760	39
Dearborn NA	5687698	685272	1899318043	2015	251654	39
Dearborn NA	5952603	712461	1987920583	2018	257742	39
Dearborn NA	6186441	735862	2005371969	2021	263978	39
Hamilton	21859452	23170766	7241529618	2005	862422	39
Hamilton	22124503	23447460	7421005221	2008	890352	39
Hamilton	22426021	23803187	7503612070	2011	904655	39
Hamilton	22849494	24259554	7630232069	2015	933953	39
Hamilton	23630554	25096560	7891617279	2018	956548	39
Hamilton	24098698	25596996	7811737549	2021	979689	39
Warren	5884216	6263010	1949617151	2005	233106	39
Warren	6057338	6464217	2031753523	2008	240655	39
Warren	6406284	6835660	2143504189	2011	244521	39
Warren	6842828	7279441	2285055662	2015	252440	39
Warren	7368035	7836746	2460615706	2018	258547	39
Warren	7707500	8194596	2498432370	2021	264802	39

4.2 Source type population and source type VMT distribution

A combination of local and MOVES default data were used for the source type populations. The source type VMT fractions are based on the ratio of MOVES default source type population and MOVES default source type VMT. It is assumed that the growth rate of source type populations is equal to the regional annual household growth rate of 0.8%. Source type VMT fractions are the same for all analysis years.

Table 27: Base Year Source Type Population and VMT Fraction

stateID	sourceTypeID	sourceTypePopulation	sourceTypeFraction	sourceTypeVMTFraction
39	11	69121	0.038559	0.005026
39	21	1200827	0.669872	0.555019
39	31	486373	0.271319	0.277725
39	32	15947	0.008896	0.092783
39	41	458	0.000255	0.000754
39	42	82	0.000046	0.000225
39	43	3681	0.002053	0.000858
39	51	0	0.000000	0.000644
39	52	369	0.000206	0.020527
39	53	364	0.000203	0.002663
39	54	4928	0.002749	0.001224
39	61	4879	0.002722	0.017977
39	62	5593	0.003120	0.024576
21	11	8040	0.021370	0.005063
21	21	198623	0.527931	0.551736
21	31	121506	0.322958	0.275546
21	32	40593	0.107894	0.092055
21	41	128	0.000340	0.000745
21	42	21	0.000056	0.000222
21	43	985	0.002618	0.000847
21	51	0	0.000000	0.000641
21	52	767	0.002039	0.020433
21	53	757	0.002012	0.002650
21	54	1390	0.003695	0.001218
21	61	1593	0.004234	0.020634
21	62	1826	0.004853	0.028210

4.3 Hourly distribution

MOVES default hourly distribution by source type was used during the post-processing.

4.4 Road type distribution

Road type VMT fractions by source type are default values, except for passenger cars (source type 21) and passenger trucks (source type 31). VMT fractions from the OKI TDM are used for passenger cars and passenger trucks.

Table 28: Base Year Source Type Population and VMT Fraction

sourceTypeID	roadTypeID	roadTypeVMTFraction	stateID
21	1	0	21
21	2	0.0952	21
21	3	0.0818	21
21	4	0.4741	21
21	5	0.3489	21
31	1	0	21
31	2	0.0952	21
31	3	0.0818	21
31	4	0.4741	21
31	5	0.3489	21
21	1	0	39
21	2	0.0436	39
21	3	0.1256	39
21	4	0.4143	39
21	5	0.4165	39
31	1	0	39
31	2	0.0436	39
31	3	0.1256	39
31	4	0.4143	39
31	5	0.4165	39

4.5 Average speed distribution

Average speed fractions for each of the 16 speed bins are provided by the OKI TDM. The average speed fractions vary by state, year, road type and hour.

Table 29: Average Speed Distribution (Example: only road type 2, year 2011, Ohio values shown)

roadTypeID	hourID	avgSpeedBinID	avgSpeedFraction	YearID	stateID
2	1	1	0.00000000	2011	39
2	1	2	0.00000000	2011	39
2	1	3	0.00000000	2011	39
2	1	4	0.00000000	2011	39
2	1	5	0.00000000	2011	39
2	1	6	0.00000000	2011	39
2	1	7	0.00000000	2011	39
2	1	8	0.00000000	2011	39

2	1	9	0.00000000	2011	39
2	1	10	0.11922233	2011	39
2	1	11	0.12547629	2011	39
2	1	12	0.19752816	2011	39
2	1	13	0.00589550	2011	39
2	1	14	0.00000000	2011	39
2	1	15	0.55187773	2011	39
2	1	16	0.00000000	2011	39
2	2	1	0.00000000	2011	39
2	2	2	0.00000000	2011	39
2	2	3	0.00000000	2011	39
2	2	4	0.00000000	2011	39
2	2	5	0.00000000	2011	39
2	2	6	0.00000000	2011	39
2	2	7	0.00000000	2011	39
2	2	8	0.00000000	2011	39
2	2	9	0.00000000	2011	39
2	2	10	0.11922233	2011	39
2	2	11	0.12547629	2011	39
2	2	12	0.19752816	2011	39
2	2	13	0.00589550	2011	39
2	2	14	0.00000000	2011	39
2	2	15	0.55187773	2011	39
2	2	16	0.00000000	2011	39
2	3	1	0.00000000	2011	39
2	3	2	0.00000000	2011	39
2	3	3	0.00000000	2011	39
2	3	4	0.00000000	2011	39
2	3	5	0.00000000	2011	39
2	3	6	0.00000000	2011	39
2	3	7	0.00000000	2011	39
2	3	8	0.00000000	2011	39
2	3	9	0.00000000	2011	39
2	3	10	0.11922233	2011	39
2	3	11	0.12547629	2011	39
2	3	12	0.19752816	2011	39
2	3	13	0.00589550	2011	39
2	3	14	0.06436270	2011	39

2	3	15	0.48751503	2011	39
2	3	16	0.00000000	2011	39
2	4	1	0.00000000	2011	39
2	4	2	0.00000000	2011	39
2	4	3	0.00000000	2011	39
2	4	4	0.00000000	2011	39
2	4	5	0.00000000	2011	39
2	4	6	0.00000000	2011	39
2	4	7	0.00000000	2011	39
2	4	8	0.00000000	2011	39
2	4	9	0.00000000	2011	39
2	4	10	0.11922233	2011	39
2	4	11	0.12547629	2011	39
2	4	12	0.19752816	2011	39
2	4	13	0.00589550	2011	39
2	4	14	0.12369152	2011	39
2	4	15	0.42818621	2011	39
2	4	16	0.00000000	2011	39
2	5	1	0.00000000	2011	39
2	5	2	0.00000000	2011	39
2	5	3	0.00000000	2011	39
2	5	4	0.00000000	2011	39
2	5	5	0.00000000	2011	39
2	5	6	0.00000000	2011	39
2	5	7	0.00000000	2011	39
2	5	8	0.00000000	2011	39
2	5	9	0.00000000	2011	39
2	5	10	0.11922233	2011	39
2	5	11	0.12547629	2011	39
2	5	12	0.26189086	2011	39
2	5	13	0.09782827	2011	39
2	5	14	0.06250896	2011	39
2	5	15	0.33307330	2011	39
2	5	16	0.00000000	2011	39
2	6	1	0.00000000	2011	39
2	6	2	0.12369152	2011	39
2	6	3	0.03260396	2011	39
2	6	4	0.03085494	2011	39

2	6	5	0.01601927	2011	39
2	6	6	0.01563475	2011	39
2	6	7	0.00000000	2011	39
2	6	8	0.00000000	2011	39
2	6	9	0.00000000	2011	39
2	6	10	0.11922233	2011	39
2	6	11	0.12547629	2011	39
2	6	12	0.19752816	2011	39
2	6	13	0.00589550	2011	39
2	6	14	0.00278921	2011	39
2	6	15	0.33028409	2011	39
2	6	16	0.00000000	2011	39
2	7	1	0.21880443	2011	39
2	7	2	0.00000000	2011	39
2	7	3	0.00278921	2011	39
2	7	4	0.00000000	2011	39
2	7	5	0.01131028	2011	39
2	7	6	0.03548550	2011	39
2	7	7	0.03519436	2011	39
2	7	8	0.03514937	2011	39
2	7	9	0.00617093	2011	39
2	7	10	0.08564905	2011	39
2	7	11	0.14691446	2011	39
2	7	12	0.13064235	2011	39
2	7	13	0.00589550	2011	39
2	7	14	0.14352342	2011	39
2	7	15	0.14247115	2011	39
2	7	16	0.00000000	2011	39
2	8	1	0.21880443	2011	39
2	8	2	0.00278921	2011	39
2	8	3	0.01131028	2011	39
2	8	4	0.01356074	2011	39
2	8	5	0.05711912	2011	39
2	8	6	0.03514937	2011	39
2	8	7	0.02902228	2011	39
2	8	8	0.01193860	2011	39
2	8	9	0.07229727	2011	39
2	8	10	0.05473480	2011	39

2	8	11	0.08493157	2011	39
2	8	12	0.11645227	2011	39
2	8	13	0.04360641	2011	39
2	8	14	0.20648097	2011	39
2	8	15	0.04180267	2011	39
2	8	16	0.00000000	2011	39
2	9	1	0.21880443	2011	39
2	9	2	0.00000000	2011	39
2	9	3	0.00000000	2011	39
2	9	4	0.00000000	2011	39
2	9	5	0.00000000	2011	39
2	9	6	0.00278921	2011	39
2	9	7	0.00000000	2011	39
2	9	8	0.04679577	2011	39
2	9	9	0.03519436	2011	39
2	9	10	0.08369185	2011	39
2	9	11	0.14590244	2011	39
2	9	12	0.15349370	2011	39
2	9	13	0.02733367	2011	39
2	9	14	0.03771092	2011	39
2	9	15	0.24828365	2011	39
2	9	16	0.00000000	2011	39
2	10	1	0.15629548	2011	39
2	10	2	0.04687421	2011	39
2	10	3	0.01563475	2011	39
2	10	4	0.00000000	2011	39
2	10	5	0.00000000	2011	39
2	10	6	0.00000000	2011	39
2	10	7	0.00000000	2011	39
2	10	8	0.00000000	2011	39
2	10	9	0.00000000	2011	39
2	10	10	0.11922233	2011	39
2	10	11	0.13957578	2011	39
2	10	12	0.18621788	2011	39
2	10	13	0.00589550	2011	39
2	10	14	0.04428952	2011	39
2	10	15	0.28599457	2011	39
2	10	16	0.00000000	2011	39

2	11	1	0.06436270	2011	39
2	11	2	0.12278771	2011	39
2	11	3	0.01601927	2011	39
2	11	4	0.01563475	2011	39
2	11	5	0.00000000	2011	39
2	11	6	0.00000000	2011	39
2	11	7	0.00000000	2011	39
2	11	8	0.00000000	2011	39
2	11	9	0.00000000	2011	39
2	11	10	0.11922233	2011	39
2	11	11	0.13678656	2011	39
2	11	12	0.18900709	2011	39
2	11	13	0.00589550	2011	39
2	11	14	0.02285135	2011	39
2	11	15	0.30743274	2011	39
2	11	16	0.00000000	2011	39
2	12	1	0.06436270	2011	39
2	12	2	0.09193278	2011	39
2	12	3	0.04687421	2011	39
2	12	4	0.01563475	2011	39
2	12	5	0.00000000	2011	39
2	12	6	0.00000000	2011	39
2	12	7	0.00000000	2011	39
2	12	8	0.00000000	2011	39
2	12	9	0.00000000	2011	39
2	12	10	0.11922233	2011	39
2	12	11	0.12547629	2011	39
2	12	12	0.20031737	2011	39
2	12	13	0.00589550	2011	39
2	12	14	0.02285135	2011	39
2	12	15	0.30743274	2011	39
2	12	16	0.00000000	2011	39
2	13	1	0.06436270	2011	39
2	13	2	0.09193278	2011	39
2	13	3	0.04687421	2011	39
2	13	4	0.01563475	2011	39
2	13	5	0.00000000	2011	39
2	13	6	0.00000000	2011	39

2	13	7	0.00000000	2011	39
2	13	8	0.00000000	2011	39
2	13	9	0.00000000	2011	39
2	13	10	0.11922233	2011	39
2	13	11	0.12547629	2011	39
2	13	12	0.19752816	2011	39
2	13	13	0.00868471	2011	39
2	13	14	0.00000000	2011	39
2	13	15	0.33028409	2011	39
2	13	16	0.00000000	2011	39
2	14	1	0.06436270	2011	39
2	14	2	0.09193278	2011	39
2	14	3	0.03085494	2011	39
2	14	4	0.03165402	2011	39
2	14	5	0.00000000	2011	39
2	14	6	0.00000000	2011	39
2	14	7	0.00000000	2011	39
2	14	8	0.00000000	2011	39
2	14	9	0.00000000	2011	39
2	14	10	0.11922233	2011	39
2	14	11	0.12547629	2011	39
2	14	12	0.19752816	2011	39
2	14	13	0.00868471	2011	39
2	14	14	0.00000000	2011	39
2	14	15	0.33028409	2011	39
2	14	16	0.00000000	2011	39
2	15	1	0.06436270	2011	39
2	15	2	0.09193278	2011	39
2	15	3	0.04687421	2011	39
2	15	4	0.01563475	2011	39
2	15	5	0.00000000	2011	39
2	15	6	0.00000000	2011	39
2	15	7	0.00000000	2011	39
2	15	8	0.00000000	2011	39
2	15	9	0.00000000	2011	39
2	15	10	0.11922233	2011	39
2	15	11	0.12547629	2011	39
2	15	12	0.19752816	2011	39

2	15	13	0.00868471	2011	39
2	15	14	0.02285135	2011	39
2	15	15	0.30743274	2011	39
2	15	16	0.00000000	2011	39
2	16	1	0.12369152	2011	39
2	16	2	0.07947816	2011	39
2	16	3	0.01563475	2011	39
2	16	4	0.00000000	2011	39
2	16	5	0.00000000	2011	39
2	16	6	0.00000000	2011	39
2	16	7	0.00000000	2011	39
2	16	8	0.00000000	2011	39
2	16	9	0.00000000	2011	39
2	16	10	0.11922233	2011	39
2	16	11	0.13957578	2011	39
2	16	12	0.18621788	2011	39
2	16	13	0.00589550	2011	39
2	16	14	0.04428952	2011	39
2	16	15	0.28599457	2011	39
2	16	16	0.00000000	2011	39
2	17	1	0.20316968	2011	39
2	17	2	0.01563475	2011	39
2	17	3	0.00000000	2011	39
2	17	4	0.00000000	2011	39
2	17	5	0.00000000	2011	39
2	17	6	0.00000000	2011	39
2	17	7	0.00278921	2011	39
2	17	8	0.02487101	2011	39
2	17	9	0.05711912	2011	39
2	17	10	0.05722137	2011	39
2	17	11	0.15811770	2011	39
2	17	12	0.14489757	2011	39
2	17	13	0.05018502	2011	39
2	17	14	0.00000000	2011	39
2	17	15	0.28599457	2011	39
2	17	16	0.00000000	2011	39
2	18	1	0.15629548	2011	39
2	18	2	0.04687421	2011	39

2	18	3	0.01563475	2011	39
2	18	4	0.00000000	2011	39
2	18	5	0.00000000	2011	39
2	18	6	0.00000000	2011	39
2	18	7	0.00000000	2011	39
2	18	8	0.00000000	2011	39
2	18	9	0.00000000	2011	39
2	18	10	0.11922233	2011	39
2	18	11	0.13957578	2011	39
2	18	12	0.18621788	2011	39
2	18	13	0.00589550	2011	39
2	18	14	0.04428952	2011	39
2	18	15	0.28599457	2011	39
2	18	16	0.00000000	2011	39
2	19	1	0.00000000	2011	39
2	19	2	0.00000000	2011	39
2	19	3	0.00000000	2011	39
2	19	4	0.00000000	2011	39
2	19	5	0.06436270	2011	39
2	19	6	0.00000000	2011	39
2	19	7	0.05932882	2011	39
2	19	8	0.03260396	2011	39
2	19	9	0.00000000	2011	39
2	19	10	0.15007727	2011	39
2	19	11	0.14149556	2011	39
2	19	12	0.21316291	2011	39
2	19	13	0.00589550	2011	39
2	19	14	0.00000000	2011	39
2	19	15	0.33307330	2011	39
2	19	16	0.00000000	2011	39
2	20	1	0.00000000	2011	39
2	20	2	0.00000000	2011	39
2	20	3	0.00000000	2011	39
2	20	4	0.00000000	2011	39
2	20	5	0.00000000	2011	39
2	20	6	0.00000000	2011	39
2	20	7	0.00000000	2011	39
2	20	8	0.00000000	2011	39

2	20	9	0.00000000	2011	39
2	20	10	0.11922233	2011	39
2	20	11	0.12547629	2011	39
2	20	12	0.19752816	2011	39
2	20	13	0.00589550	2011	39
2	20	14	0.15629548	2011	39
2	20	15	0.39558226	2011	39
2	20	16	0.00000000	2011	39
2	21	1	0.00000000	2011	39
2	21	2	0.00000000	2011	39
2	21	3	0.00000000	2011	39
2	21	4	0.00000000	2011	39
2	21	5	0.00000000	2011	39
2	21	6	0.00000000	2011	39
2	21	7	0.00000000	2011	39
2	21	8	0.00000000	2011	39
2	21	9	0.00000000	2011	39
2	21	10	0.11922233	2011	39
2	21	11	0.12547629	2011	39
2	21	12	0.19752816	2011	39
2	21	13	0.00589550	2011	39
2	21	14	0.00000000	2011	39
2	21	15	0.55187773	2011	39
2	21	16	0.00000000	2011	39
2	22	1	0.00000000	2011	39
2	22	2	0.00000000	2011	39
2	22	3	0.00000000	2011	39
2	22	4	0.00000000	2011	39
2	22	5	0.00000000	2011	39
2	22	6	0.00000000	2011	39
2	22	7	0.00000000	2011	39
2	22	8	0.00000000	2011	39
2	22	9	0.00000000	2011	39
2	22	10	0.11922233	2011	39
2	22	11	0.12547629	2011	39
2	22	12	0.19752816	2011	39
2	22	13	0.00589550	2011	39
2	22	14	0.00000000	2011	39

2	22	15	0.55187773	2011	39
2	22	16	0.00000000	2011	39
2	23	1	0.00000000	2011	39
2	23	2	0.00000000	2011	39
2	23	3	0.00000000	2011	39
2	23	4	0.00000000	2011	39
2	23	5	0.00000000	2011	39
2	23	6	0.00000000	2011	39
2	23	7	0.00000000	2011	39
2	23	8	0.00000000	2011	39
2	23	9	0.00000000	2011	39
2	23	10	0.11922233	2011	39
2	23	11	0.12547629	2011	39
2	23	12	0.19752816	2011	39
2	23	13	0.00589550	2011	39
2	23	14	0.00000000	2011	39
2	23	15	0.55187773	2011	39
2	23	16	0.00000000	2011	39
2	24	1	0.00000000	2011	39
2	24	2	0.00000000	2011	39
2	24	3	0.00000000	2011	39
2	24	4	0.00000000	2011	39
2	24	5	0.00000000	2011	39
2	24	6	0.00000000	2011	39
2	24	7	0.00000000	2011	39
2	24	8	0.00000000	2011	39
2	24	9	0.00000000	2011	39
2	24	10	0.11922233	2011	39
2	24	11	0.12547629	2011	39
2	24	12	0.19752816	2011	39
2	24	13	0.00589550	2011	39
2	24	14	0.00000000	2011	39
2	24	15	0.55187773	2011	39
2	24	16	0.00000000	2011	39

4.6 Creating a VMT Table by County, Year, Source Type, Hour, Road Type, and Average Speed Bin

The 'CountyVMT' query creates a County VMT Table by source type, hour, road type and average speed utilizing the VMT distribution factors described in 4.2, 4.3, 4.4 and 4.5. The SQL commands for this query are shown in Table 30.

Table 30 :County VMT Table Query

```
SELECT VMT.yearID, VMT.State, roadtypedistribution1.stateID, VMT.County,
roadtypedistribution1.sourceTypeID, hourvmtfraction.hourID,
roadtypedistribution1.roadTypeID, avgSpeedDistribution.avgSpeedBinID,
sourcetypepopulation.sourceTypeFraction, hourvmtfraction.hourVMTFraction,
roadtypedistribution1.roadTypeVMTFraction,
avgSpeedDistribution.avgSpeedFraction, First(VMT.[Annual VMT]) AS
[FirstOfAnnual VMT], First(VMT.[Summer VMT]) AS [FirstOfSummer VMT],
[FirstOfSummer
VMT]*[hourVMTFraction]*[sourceTypeFraction]*[roadTypeVMTFraction]*[avgSpeedFr
action] AS DailyVMT, [FirstOfAnnual
VMT]*[sourceTypeFraction]*[hourVMTFraction]*[roadTypeVMTFraction]*[avgSpeedFr
action] AS AnnualizedVMT INTO CountyVMT_Table
FROM (((avgSpeedDistribution INNER JOIN hourvmtfraction ON
(avgSpeedDistribution.hourDayID = hourvmtfraction.hourID) AND
(avgSpeedDistribution.roadTypeID = hourvmtfraction.roadTypeID) AND
(avgSpeedDistribution.sourceTypeID = hourvmtfraction.sourceTypeID)) INNER
JOIN roadtypedistribution1 ON (avgSpeedDistribution.stateID =
roadtypedistribution1.stateID) AND (avgSpeedDistribution.roadTypeID =
roadtypedistribution1.roadTypeID) AND (avgSpeedDistribution.sourceTypeID =
roadtypedistribution1.sourceTypeID)) INNER JOIN sourcetypepopulation ON
(avgSpeedDistribution.sourceTypeID = sourcetypepopulation.sourceTypeID) AND
(avgSpeedDistribution.stateID = sourcetypepopulation.stateID)) INNER JOIN
VMT ON (avgSpeedDistribution.YearID = VMT.yearID) AND
(avgSpeedDistribution.stateID = VMT.stateID)
GROUP BY VMT.yearID, VMT.State, roadtypedistribution1.stateID, VMT.County,
roadtypedistribution1.sourceTypeID, hourvmtfraction.hourID,
roadtypedistribution1.roadTypeID, avgSpeedDistribution.avgSpeedBinID,
sourcetypepopulation.sourceTypeFraction, hourvmtfraction.hourVMTFraction,
roadtypedistribution1.roadTypeVMTFraction,
avgSpeedDistribution.avgSpeedFraction
HAVING (((avgSpeedDistribution.avgSpeedFraction)>0))
ORDER BY VMT.yearID, roadtypedistribution1.stateID, VMT.County,
hourvmtfraction.hourID;
```

5. Combining VMT and Emission Rates; Calculating Total Emissions

5.1 Summarizing Distance-based Emissions by Source Type

The daily VMT and annual VMT in each county, year, hour, source type, road type, and speed bin is multiplied by the appropriate rate per distance for each pollutant. This query is shown in Table 31.

Table 31 :Emissions distance Query

```
SELECT CountyVMT_Table.stateID, CountyVMT_Table.State,
CountyVMT_Table.County, CountyVMT_Table.yearID,
rateperdistance_state.monthID, CountyVMT_Table.hourID,
rateperdistance_state.sourceTypeID, CountyVMT_Table.roadTypeID,
CountyVMT_Table.avgSpeedBinID, rateperdistance_state.pollutantID,
CountyVMT_Table.DailyVMT, CountyVMT_Table.AnnualizedVMT,
rateperdistance_state.SumOfratePerDistance, [DailyVMT]*[SumOfratePerDistance]
AS EmissionsDist, [AnnualizedVMT]*[SumOfratePerDistance] AS
AnnualEmissionsDist
FROM rateperdistance_state INNER JOIN CountyVMT_Table ON
(rateperdistance_state.avgSpeedBinID = CountyVMT_Table.avgSpeedBinID) AND
(rateperdistance_state.roadTypeID = CountyVMT_Table.roadTypeID) AND
(rateperdistance_state.sourceTypeID = CountyVMT_Table.sourceTypeID) AND
(rateperdistance_state.hourID = CountyVMT_Table.hourID) AND
(rateperdistance_state.StateID = CountyVMT_Table.stateID) AND
(rateperdistance_state.yearID = CountyVMT_Table.yearID)
GROUP BY CountyVMT_Table.stateID, CountyVMT_Table.State,
CountyVMT_Table.County, CountyVMT_Table.yearID,
rateperdistance_state.monthID, CountyVMT_Table.hourID,
rateperdistance_state.sourceTypeID, CountyVMT_Table.roadTypeID,
CountyVMT_Table.avgSpeedBinID, rateperdistance_state.pollutantID,
CountyVMT_Table.DailyVMT, CountyVMT_Table.AnnualizedVMT,
rateperdistance_state.SumOfratePerDistance;
```

A second query further summarizes the emissions by source type. This is necessary in order to combine with vehicle-based emissions that are independent of road type and speed.

5.2 Summarizing Vehicle-based Emissions by Source type

The source population for each county, year, hour, and source type is multiplied by the rate per vehicle for each pollutant. This query is shown in Table 32.

Table 32: Emissions Vehicle Query

```
SELECT VMT.stateID, VMT.County, ratepervehicle_state.yearID,
ratepervehicle_state.monthID, ratepervehicle_state.hourID,
ratepervehicle_state.sourceTypeID, sourcetypepopulation.sourceTypeFraction,
VMT.SourceTypePopulation, ratepervehicle_state.pollutantID,
ratepervehicle_state.SumOfratePerVehicle, First(VMT.BudgetAreaPop) AS
FirstOfBudgetAreaPop,
((Nz([VMT]![sourceTypePopulation]*[sourceTypeFraction],0)/24)) AS STPop,
Nz([VMT]![sourceTypePopulation]*[sourceTypeFraction]*[SumOfratePerVehicle],0)
AS emissionsVehicle,
Nz(([VMT]![sourceTypePopulation]*[sourceTypeFraction]*[SumOfratePerVehicle])*
365,0) AS AnnualemissionsVehicle
FROM sourcetypepopulation INNER JOIN (ratepervehicle_state INNER JOIN VMT ON
(ratepervehicle_state.yearID = VMT.yearID) AND (ratepervehicle_state.StateID
= VMT.stateID)) ON (sourcetypepopulation.sourceTypeID =
ratepervehicle_state.sourceTypeID) AND (sourcetypepopulation.stateID =
ratepervehicle_state.StateID)
GROUP BY VMT.stateID, VMT.County, ratepervehicle_state.yearID,
ratepervehicle_state.monthID, ratepervehicle_state.hourID,
ratepervehicle_state.sourceTypeID, sourcetypepopulation.sourceTypeFraction,
VMT.SourceTypePopulation, ratepervehicle_state.pollutantID,
ratepervehicle_state.SumOfratePerVehicle;
```

5.3 Ramp Emissions

Ramp emission rates, calculated as discussed in Section 3, are multiplied by ramp VMT in each county, year and source type. This query is shown in Table 33.

Table 33: Ramp Emissions Query

```
SELECT VMT.stateID, VMT.County, VMT.yearID, hourvmtfraction.hourID, hourvmtfraction.sourceTypeID,
hourvmtfraction.hourVMTFraction, ramp_rate.pollutantID, VMT.[Ramp VMT], ([Ramp
VMT]*[hourVMTFraction])/13 AS HourlyRampVMT, ramp_rate.ramprate, [HourlyRampVMT]*[ramprate]
AS RampEmissions, ([HourlyRampVMT]*[ramprate])*340 AS RampEmissionsAnnual
FROM hourvmtfraction INNER JOIN (VMT INNER JOIN ramp_rate ON (VMT.stateID = ramp_rate.StateID)
AND (VMT.yearID = ramp_rate.yearID)) ON hourvmtfraction.hourID = ramp_rate.hourID
WHERE (((hourvmtfraction.roadTypeID)=4))
ORDER BY VMT.stateID, VMT.County, VMT.yearID, hourvmtfraction.hourID,
hourvmtfraction.sourceTypeID, ramp_rate.pollutantID;
```

5.4 Summarizing Results

Distance-based emissions by source type, vehicle-based emissions by source type, and ramp emissions by source type are summed by county, year and pollutant. This query is shown below. This is also where criteria may be set for limiting the results by state, county, year or pollutant. A sum of VMT and source type population is also useful as a verification that all steps were run properly. The appropriate monthID criteria should be set here. The annual average temperature profile is contained in April (monthID=4). July (monthID=7) should be used for summer weekday emissions.

Table 34:Results Query

```
SELECT EmissionsDistance_bySourceType.State, EmissionsDistance_bySourceType.County,
EmissionsDistance_bySourceType.yearID, EmissionsDistance_bySourceType.pollutantName,
Sum(EmissionsDistance_bySourceType.SumOfDailyVMT) AS SumOfSumOfDailyVMT,
Sum(RampEmissions_Query.HourlyRampVMT) AS SumOfHourlyRampVMT,
Sum(EmissionsDistance_bySourceType.SumOfAnnualizedVMT) AS SumOfSumOfAnnualizedVMT,
First(EmissionsVehicle_Query.SourceTypePopulation) AS FirstOfSourceTypePopulation,
Sum(EmissionsDistance_bySourceType.SumOfEmissionsDist) AS SumOfSumOfEmissionsDist,
Sum(Nz([emissionsVehicle],0)) AS EmissionsVeh, Sum(RampEmissions_Query.RampEmissions) AS
SumOfRampEmissions, Sum(EmissionsDistance_bySourceType.SumOfAnnualEmissionsDist) AS
SumOfSumOfAnnualEmissionsDist, Sum(Nz([AnnualemissionsVehicle],0)) AS AnnualEmissionsVeh,
Sum(RampEmissions_Query.RampEmissionsAnnual) AS SumOfRampEmissionsAnnual,
(([SumOfSumOfEmissionsDist]+[EmissionsVeh]+[SumOfHourlyRampVMT])/1000)*0.001102 AS
DailyEmissionsTONS,
(([SumOfSumOfAnnualEmissionsDist]+[AnnualEmissionsVeh]+[SumOfRampEmissionsAnnual])/1000)*0.0
01102 AS AnnualEmissionsTONS,
Sum([RampEmissions_Query]![HourlyRampVMT]+[EmissionsDistance_bySourceType]![SumOfDailyVMT]
) AS AllVMT
```

```
FROM (EmissionsDistance_bySourceType LEFT JOIN EmissionsVehicle_Query ON
(EmissionsDistance_bySourceType.pollutantID = EmissionsVehicle_Query.pollutantID) AND
(EmissionsDistance_bySourceType.sourceTypeID = EmissionsVehicle_Query.sourceTypeID) AND
(EmissionsDistance_bySourceType.hourID = EmissionsVehicle_Query.hourID) AND
(EmissionsDistance_bySourceType.monthID = EmissionsVehicle_Query.monthID) AND
(EmissionsDistance_bySourceType.yearID = EmissionsVehicle_Query.yearID) AND
(EmissionsDistance_bySourceType.County = EmissionsVehicle_Query.County)) INNER JOIN
RampEmissions_Query ON (EmissionsDistance_bySourceType.County = RampEmissions_Query.County)
AND (EmissionsDistance_bySourceType.yearID = RampEmissions_Query.yearID) AND
(EmissionsDistance_bySourceType.hourID = RampEmissions_Query.hourID) AND
(EmissionsDistance_bySourceType.sourceTypeID = RampEmissions_Query.sourceTypeID) AND
(EmissionsDistance_bySourceType.pollutantID = RampEmissions_Query.pollutantID)
GROUP BY EmissionsDistance_bySourceType.State, EmissionsDistance_bySourceType.County,
EmissionsDistance_bySourceType.yearID, EmissionsDistance_bySourceType.pollutantName,
EmissionsDistance_bySourceType.monthID, EmissionsDistance_bySourceType.pollutantID
HAVING (((EmissionsDistance_bySourceType.monthID)=4));
```

APPENDIX G

Indiana Department of Environmental Management (IDEM) – Area Source Inventory Standard Operating Procedure

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Area Source Inventory
S-006-OAQ-R-MO-08-S-R1

Standard Operating Procedure

Office: Office of Air Quality
Branch: Air Programs Branch
Section: Technical Support and Modeling Section

Revised: 02/27/2008 **Revision *Cycle:*** 2 years
Effective date: 02/15/07

Scope of operations
This SOP is to identify source categories and develop emissions not calculated in point source inventories. This data is compiled every three years as mandated by EPA.

Scope of applicability
This SOP is for the Senior Environmental Manager and the Environmental Manager in the Emissions Group.

Authorized Signatures

I approve and authorize this Standard Operating Procedure:

Branch Chief
Scott Deloney
Typed/Printed
Signature
3/12/08
Date

Section Chief
Ken Ritter
Typed/Printed
Signature
3/10/08
Date

Section QA Contact
Michele Boner
Typed/Printed
Signature
3/10/08
Date

Branch QA Coordinator
Chris Pedersen
Typed/Printed
Signature
3-10-08
Date

Author
Michele Boner
Typed/Printed
Signature
3/10/08
Date

This Standard Operating Procedure is consistent with agency requirements.

Indiana Department of Environmental Management
Quality Assurance Program
Planning and Assessment
3-17-08
Date

Table of Contents

1. Overview work flow chart

The process described is not part of a larger system and does not need an Overview work flow chart.

2. Definitions

AP-42 – Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources (January 1995) plus Supplements A – F (Updates 2001 – 2004). AP-42 can be obtained at www.epa.gov/ttn/chief/ap42/.

Area Sources - A collection of similar emission units within a geographic area that collectively represent individual sources that are small and numerous and have not been inventoried as a specific point, mobile, or biogenic source.

Authorized - Established by official authority and usage; as with a policy, standard operating procedure (SOP), or quality assurance project plan (QAPP) that is signed and dated.

EIIP (Emission Inventory Improvement Program) -The EIIP is an EPA program established in 1993 to promote the development and use of standard procedures for collecting, calculating, storing, reporting, and sharing air emissions date.

Emission Factors - An emission factor is the estimate of the quantity of pollutant released to the atmosphere (because of some operation or activity such as combustion or industrial production) divided by the level of that activity.

Process - The term “process” used when describing area sources is used to name an operation or activity that produces emissions.

NEI - National Emission Inventory Air Pollutant Emission Trends, U.S. EPA.

Standard Industrial Classification (SIC) Code - A Standard Industrial Classification code from the series of codes devised by the United States Office of Management and Budget (OMB) to classify establishments according to the type of economic activity in which they engage.

Source Classification Code (SCC) - Source Classification Code is a process-level code that describes the equipment or operation emitting pollutants.

3. Roles

Title	# of Staff	Experience	Qualifications	Location
Senior Environmental Manager	1	N/A	MS ACCESS, Emission Inventories and familiarity with the EIIP	Air Programs Branch
Environmental Manager	1	N/A	MS ACCESS, Emission Inventories and familiarity with the EIIP	Air Programs Branch

Responsibilities:

Senior Environmental Manager

Oversees work of the Environmental Manager and ensures that all goals are met. The Senior Environmental Manager also does the final upload to the NEI.

Environmental Manager

The Environmental Manager calculates the Area Source Emissions using the EIIP or other EPA guidance as provided. The Environmental Manager is also responsible for updating the SOP for the Emissions Group.

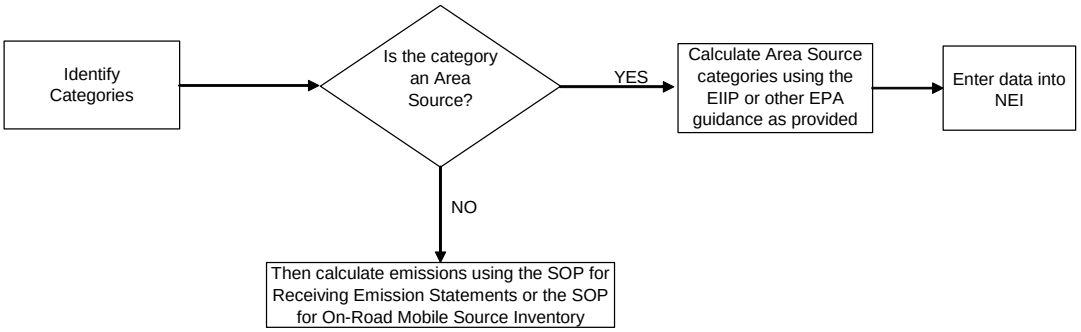
4. Description of equipment, forms, and/or software to be used

Equipment, Form, &/or Software	Who uses it?	Location
AP42	Senior Environmental Manager and Environmental Manager	EPA's website: http://www.epa.gov/ttn/chief/ap42/index.html
Emission Inventory Improvement Program (EIIP)	Senior Environmental Manager and Environmental Manager	EPA's website: http://www.epa.gov/ttn/chief/eiip/techreport/
National Emission Inventory (NEI) Air Pollutant Emission Trends, U.S. EPA	Senior Environmental Manager and Environmental Manager	EPA's website http://www.epa.gov/ttn/chief/trends/

5. Procedure

5.1 Procedural Flowchart

The procedural flowchart below titled "Area Source Inventory" is used to calculate non-point source inventories. This data is compiled every three years as mandated by EPA. The guidance followed is located in the EIIP. Emissions from area sources are calculated at the county level and consist of individual sources that are small, numerous and that have not been inventoried as specific point, mobile, or biogenic sources according to the EIIP.



5.2 Procedure

Category 1: Stationary Fuel Combustion

Sub-Category 1.1: Industrial Fuel Combustion

SCC: 2102002000, 210200400, 2102005000, 2102006000, 2102007000

Follow these steps when calculating emissions from industrial fuel combustion:

1. Obtain statewide fuel consumption for "Other Industrial" for the following fuels: coal, distillate oil, natural gas, and liquefied petroleum gas (LPG). Use the Energy Information Administration's website at http://www.eia.doe.gov/ to find fuel consumption.

   Note: As of the date of this SOP, the following steps will lead to data for fuel consumption.

   a. Go to http://www.eia.doe.gov/
   b. Click on link for the various types of fuel consumption
   c. Click on consumption tab for state totals

2. To avoid double calculating the various fuel combustions, subtract reported source totals from the total statewide fuel consumption by querying the total process rates for the various SCC codes using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb. The remaining number is the area source fuel consumption for the state.

3. To distribute the remaining fuel to the county level, calculate the ratio of county to state employment for the manufacturing sector by dividing the number of Manufacturing Employees for each county by the number of manufacturing employees statewide. Use the County Business Patterns website at http://www.census.gov/ to find the number of manufacturing employees for each county.

   Note: As of the date of this SOP, the following steps will lead to data for Economic Census.

   a. Go to http://www.census.gov/
   b. Click on Economic Census
   c. Under 2002 Reports by State, use the down arrow key to select Indiana
   d. Now, select each of the counties to find the county manufacturing employees
   e. Use the total of employees for manufacturing under the paid employees' column

4. Multiply the ratio calculated above in step 3 by the area source fuel consumption to distribute the fuel to the county level. The remaining number is the process rate for each county. Multiply the process rate by the appropriate EPA emission factors for the various fuels for industrial manufacturing found in AP-42, Fifth Edition, Volume 1, Chapter 1, External Combustion Sources at http://www.epa.gov/ttn/chief/ap42/ch01/.

Sub-Category 1.2: Commercial/Institutional Fuel Combustion

SCC: 2103004000, 2103005000, 2103006000, 2103007000

Follow these steps when calculating emissions from commercial/institutional fuel combustion:

1. Obtain statewide fuel consumption for "Commercial" for the following fuels: distillate fuel oil, liquefied petroleum gas (LPG), natural gas, and residual fuel oil. Use the Energy Information Administration's website at http://www.eia.doe.gov/ to find fuel consumption.

   Note: Use the steps in sub-category 1.1-1 to navigate through the Energy Information Administration's website.

2. To avoid double calculating the various fuel combustions, subtract reported source totals from the total statewide fuel consumption by querying the total process rates for the various fuels using the SIC codes greater than 4999 using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb. These are the SIC codes that identify all the commercial/institutional area sources.

3. To distribute the remaining fuel to the county level, calculate the ratio of county to state employment for the commercial/institutional sector by dividing the number of commercial/institutional employees for each county by the number of commercial/institutional employees statewide. Use the County Business Patterns website at http://www.census.gov/ to find the number of commercial/institutional employees for each county.

   Note: Use the steps in sub-category 1.1-3 to navigate through the U.S. Census Bureau's website.

4. Multiply the ratio calculated above in step 3 by the area source fuel consumption to distribute the fuel to the county level. The remaining number is the process rate for each county. Multiply the process rate by the appropriate EPA emission factors for the various fuels for commercial/institutional found in AP-42, Fifth Edition, Volume 1, Chapter 1, External Combustion Sources at http://www.epa.gov/ttn/chief/ap42/ch01/.

Sub-Category 1.3: Residential Fuel Combustion

SCC: 2104002000, 2104004000, 2104006000, 2104007000

Follow these steps when calculating emissions from residential fuel combustion:

1. Obtain statewide fuel consumption for "Residential" for the following fuels: coal, distillate oil, natural gas, and liquid petroleum gas. Use the Energy Information Administration's website at http://www.eia.doe.gov/ to find fuel consumption.

   Note: Use the steps in sub-category 1.1-1 to navigate through the Energy Information Administration's website.

2. To distribute residential fuel to the county level, calculate the ratio of county fuel usage to statewide fuel usage using the breakdown of fuels by household per county divided by the breakdown of fuels by household per state using the U.S. Census Bureau's website at http://www.census.gov/ .

   Note: As of the date of this SOP, the following steps will lead to data for breakdown of fuels by household.

   a. Go to http://www.census.gov/
   b. On the left hand side click on "American Fact Finder"
   c. Using the drop down menu, click on Indiana
   d. Scroll to "Housing Characteristics" and select "show more"
   e. On the left hand side, select "change geography (state, county, place…)"
   f. Using the drop down menu, select county, state, and each county name to obtain housing information

3. Multiply the ratio calculated above in step 3 by the area residential fuel use by state to distribute the fuel to the county level. The remaining number is the process rate for each county for the various fuels. Multiply the process rate by the appropriate EPA emission factors for the various fuels for residential found in AP-42, Fifth Edition, Volume 1, Chapter 1 External Combustion Sources at http://www.epa.gov/ttn/chief/ap42/ch01/.

Sub-Category 1.4: Residential Heating Using Wood

SCC: 2104008001, 2104008002, 2104008003, 2104008004, 2104008010, 2104008030, 2104008050

Follow these steps when calculating emissions from residential heating using wood:

1. Obtain statewide wood consumption for "Residential" using the Energy Information Administration's website at http://www.eia.doe.gov/. To convert the statewide wood consumption from cords of wood consumed to tons, multiply the total cords consumed by 1.25.

   Note: As of the date of this SOP, the following steps will lead to data for wood consumption.

   a. Go to http://www.eia.doe.gov/
   b. Click on Households, Buildings & Industry
   c. Under Consumption Summaries, click on "Annual"
   d. Now, over to the right click on "State Energy"
   e. Using the drop down menu at the bottom, select "Indiana"
   f. Under "Consumption" click on the "Residential" document

2. Using the ratio estimates provided by EPA found in the "Documentation For The Final 2002 NONPOINT SECTOR (FEB 06 version) NATIONAL EMISSIONS INVENTORY FOR CRITERIA AND HAZARDOUS AIR POLLUTANTS" at http://www.epa.gov/ttn/chief/net/2002inventory.html#documentaiton the number calculated above in step 1 is broken out into three categories (fireplace without inserts, fireplaces with inserts and woodstoves).

3. To distribute to the county level for the three categories above, calculate a ratio of county to state using the statewide total of households and the county total of households that burn wood found at the U.S. Census Bureau website http://www.census.gov/. The remaining number is the process rate for each county. Multiply the process rate by the appropriate EPA emission factors for each of the categories using the EIIP, Volume 3, Chapter 2, Residential Wood Combustion at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii02_apr2001.pdf.

   Note: Use the steps in sub-category 1.3-2 to navigate through the Energy Information Administration's website.

Category 2: Industrial Processes

Sub-Category 2.1: Bakeries

SCC: 2302050000

Follow these steps when calculating emissions from bakeries:

1. Calculate a per capita consumption factor using the reported weight of yeast–raised product reported under the Bread, Cake, and Frozen Bakery Products from the Economic Census Bureau at http://www.census.gov/econ/census02/ and the U.S. population at the U.S. Census Bureau at http://census,gov/.

   Note: As of the date of this SOP, the following steps will lead to data for yeast-raised product.

   a. Go to http://www.census.gov
   b. Under Business & Industry open "Economic Census"
   c. Now open "Subject Series"
   d. Under Manufacturing, open the table "Product Summary"
   e. Use the yeast – raised product under Commercial Bakeries (NAICS code 311812) and Frozen cakes, pies, and other pastries manufacturing (NAICS code 311813)

2. Multiply the per capita consumption factor calculated above in step 1 by the Indiana population found at the U.S. Census Bureau at http://www.census.gov.
   Note: As of the date of this SOP, the following steps will lead to Indiana population data.

   a. Go to http://www.census.gov
   b. Under Population Finder, use the drop down menu to select Indiana

3. To avoid double calculating the amount consumed for the state, subtract the reported process rate for both the straight-dough and sponge-dough by querying the total process rates for the SCC 30203202 (straight-dough) and SCC 30203201 (sponge-dough) using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb.

4. Multiply the remaining process rate by the straight-dough emission factor of .5 lbs VOC/1,000 pounds baked found in the EIIP, Volume 3, Area Source Method Abstracts: Baked Goods at Commercial/Retail Bakeries at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/index.html.

5. Calculate a per capita factor by dividing the Indiana population found in step 2 by the remaining process rate. Now multiply the per capita factor by each of the county populations to calculate the VOC emissions for each county.

   Note: As of the date of this SOP, the following steps will lead to county population data.

   a. Go to http://www.census.gov
   b. Under Population Finder, use the drop down menu to select Indiana
   c. Under "View more results", select the county table

Category 3: Solvent Utilization

Sub-Category 3.1: Architectural Coatings

SCC: 2401001000

Follow these steps when calculating emissions from architectural coatings:

1. Calculate an emission factor for architectural coating area sources first by adding all the solvent-based paints together and all the water based paints together using the U.S. Census Bureau's website http://www.census.gov. Use Table 1 to select all solvent-based paints and Table 2 to select all water based paints.

Table 1
National Solvent Coating Sales

Solvent Type	**1,000 gallons**
Exterior Solvent Type	XX
Interior Solvent Type	XX
Architectural Lacquers	XX
Architectural Coating N.S.K.	XX
Total Solvents	XX

Table 2
National Water Based Coating Sales

Water Type	**1,000 gallons**
Exterior Water Type	XX
Interior Water Type	XX
Total Water Type	XX

Note: As of the date of this SOP, the following steps will lead to architectural coating data.

a. Go to http://www.census.gov
b. Under Business & Industry, select more
c. Now select Current Industrial Reports (CIR)
d. Select CIRs by Subject
e. Tab down to find the report "Paints and Allied Products"

2. Now multiply the total national number for solvent-based paints by the average solvent-based coating content number (3.87 lbs VOC/gallon) and the total national number for water-based paints by the average water-based coating content number (0.74 lbs VOC/gal) found in the EIIP, Volume 3, Chapter 3: Architectural Surface Coating at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/archsfc.pdf.

3. Add the total solvent-based coatings and the water-based paints together for a total national VOC emission factor from architectural surface coating. Then divide this number by the total national population using the U.S. Census Bureau's website http://www.census.gov.

4. Multiply the number calculated above in step 3 by each of the county populations to calculate the total emissions per county.

   Note: Use the steps in sub-category 2.1-5 to navigate through the Census Bureau's website.

Sub-Category 3.2: Automobile Refinishing

SCC: 2401005000

Follow these steps when calculating emissions from automobile refinishing:

1. To avoid double calculating, first query the employees from the reported sources using the SIC 7532-Body Repair and Paint Shops using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb. Subtract this number from the county employment for the same SIC using the U.S. Census Bureau's website http://www.census.gov.

   Note: As of the date of this SOP, the following steps will lead to county employment data.

   a. Go to http://www.census.gov
   b. Under Business & Industry, select more
   c. Now select the County Business Patterns report for county
   d. Select Indiana
   e. Select each of the counties to find the number of employees for the corresponding SIC or NAICS code

2. Multiply the emission factor 3,519 lbs VOC/employee found in the EIIP, Volume 3, Chapter 13 Auto Body Refinishing at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/archsfc.pdf and the county employment found above in step 1 to calculate the VOC emissions for each county.

Sub-Category 3.3: Traffic Markings

SCC: 2401008000

Follow these steps when calculating for traffic markings:

1. First calculate the national emissions by finding the amount of sales for traffic marking paints from the U.S. Census Bureau's website http://www.census.gov and multiply 3.36 lb VOC/gallon the national average VOC content for water and solvent-based paints from the EIIP, Volume 3, Chapter 14, Traffic Markings at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii14.pdf.

Note: As of the date of this SOP, the following steps will lead to traffic marking paints.

a. Go to http://www.census.gov
b. Under Business & Industry, select more
c. Now select Current Industrial Reports (CIR)
d. Select CIRs by Subject
e. Tab down to find the report "Paints and Allied Products"
f. Use the quantity amount in 1000/gallons under "Traffic marking paints (all types: shelf goods and highway department)

2. Allocate the national emissions calculated above in step 1 to the state level by dividing the amount of money spent in Indiana by the money spent nationally on highway maintenance using the category "Total Disbursements" at the Federal Highway Administration's website http://www.fhwa.dot.gov/policy/ohim/hs04/htm/sf2.htm.

3. Calculate the emission factor for Indiana by dividing the state level emissions by the total number of roadway miles in Indiana, given by contacting the Program Development Division, Highway Statistics, Indiana Department of Transportation or the Office of Air Quality, Technical Support and Modeling Section's mobile inventory preparer.

4. Multiply the emission factor by the total number of roadway miles in each county using the information supplied from above in step 3.

Sub-Category 3.4: Industrial Surface Coating (employment based emission factor)

SCC: 2401015000, 2401020000, 2401030000, 2401040000, 2401045000, 2401055000, 2401060000, 2401065000, 2401070000, 2401075000, 2401080000

Follow these steps when calculating for industrial surface coating using the employment based emission factor:

1. Calculate an employee based emission factor for the following SIC's in the table below running a query to find the point source employment for each of the SIC's and the reported VOC emissions for each using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb.

SCC	Description	SIC's
2401015000	Factory Finished Wood	2426-2429,243-245, 2492, 2499
2401020000	Wood Furniture	25
2401030000	Paper Coating	26
2401040000	Metal Cans *	341
2401045000	Metal Coils *	3479
2401055000	Machinery and Equipment	35
2401060000	Appliances *	363
2401065000	Electronic and Other Electrical	3612, 3357
2401070000	New Motor Vehicles **	3711
2401075000	Other Transportation	37 (not 3711, 373)
2401080000	Marine Coatings	373

* Use the National default emission factor because the reporting sources are low. ** Emissions reported in point source

2. Divide the reported VOC emissions for each of the SIC's by the reported employment for each SIC. Use this number for the emission factor.

3. Subtract the number of reported employees found in step 1 from each of the SIC county totals using the U.S. Census Bureau's website http://www.census.gov. Use the remaining number for the process rate for each of the counties.

   Note: Use the steps in sub-category 3.2-1 to navigate through the County Business Patterns.

4. Multiply the process rates above found for each of the SIC's in step 4 by the emission factors found in step 3 to allocate the emissions to each of the counties.

Sub-Category 3.5: Industrial Surface Coating (default emission factor)

SCC: 2401090000, 2401100000, 2401200000

Follow these steps when calculating emissions from industrial surface coating using the default emission factor:

1. Calculate industrial surface coating emissions using the default emission factor in the EIIP, Volume 3, Chapter 8, Industrial Surface Coating at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii08.pdf and multiply by the county populations found at the U.S. Census Bureau's website http://www.census.gov.

   Note: Use the steps in 2.1-5 to navigate through U.S. Census Bureau's website.

SCC's	Description	Default Emission Factor
24-01-090-000	Miscellaneous Manufacturing	0.600 lbs VOC/person
24-01-100-000	Industrial Maintenance Coatings	0.800 lbs VOC/person
24-01-200-000	Other Special Purpose Coatings	0.800 lbs VOC/person

Sub-Category 3.6: Degreasing

SCC: 2415230000, 2415245000, 2415345000, 2415360000

Follow these steps when calculating emissions from degreasing activities:

1. Use the U.S. Census Bureau to find employment numbers for each of the counties for the categories in Table 1 below at http://www.census.gov.

   Note: Use the steps in 2.1-5 to navigate through U.S. Census Bureau's website.

Source Classification Codes and Industries Associated with Degreasing		
SCC	**SIC**	**Description**
2415230000	36	Electronic and other electronic equipment
	25	Furniture and fixtures
	33	Primary metal industries
	34	Fabricated metal products
	35	Industrial machinery and equipment
	37	Transportation equipment
	38	Instruments and related products

2415245000	39	Miscellaneous manufacturing industries
	417	Bus Terminal and Service Facilities
	423	Trucking terminal facilities
	551	New and used car dealers
	552	Used car dealers
	554	Gasoline service stations
	555	Boat dealers
	556	Recreational vehicle dealers
	753	Automotive repair shops
2415345000	25	Furniture and fixtures
	33	Primary metal industries
	34	Fabricated metal products
	35	Industrial machinery and equipment
	36	Electronic and other electronic equipment
	37	Transportation equipment
2415345000 cont.	38	Instruments and related products
	39	Miscellaneous manufacturing industries
2415360000	417	Bus Terminal and Service Facilities
	423	Trucking terminal facilities
	551	New and used car dealers
	552	Used car dealers
	554	Gasoline service stations
	555	Boat dealers
	556	Recreational vehicle dealers
	753	Automotive repair shops

2. Run a query to find reported employment numbers for each of the categories in the table above using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb.

3. Subtract the reported employment from the U.S Census Bureau's numbers to find the process rates for each of the counties.

4 Calculate the VOC emissions by multiplying the default emission factor in the EIIP, Volume 3, Chapter 6, Solvent Cleaning at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii06fin.pdf and the process rate for each of the counties found in step 3.

Sub-Category 3.7: Dry Cleaners

SCC: 2420010370

Follow these steps when calculating emissions from dry cleaners:

1. Calculate an emission factor by finding the number of employees state wide and county wide for SIC 7216(Laundry and Garment Services) at the U.S. Census Bureau's website http://www.census.gov.

Note: Use the steps in 2.1-5 to navigate through U.S. Census Bureau's website

2. Take the sum of the employment from the counties, multiply by 2000, and divide by the statewide total found in step 1. Use this number for the emission factor.

3. Calculate the process rate by running a query to find the number of reported employees for SIC 7216 using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb and subtract this number from the county total.

4. Multiply the process rate for each of the counties above by the emission factor to calculate for VOC emissions.

Sub-Category 3.8: Graphic Arts

SCC: 2425000000

Follow these steps when calculating emissions from graphic arts activities:

1. Multiply the per capita factor found in the EIIP, Volume 3, Chapter 7, Graphic Arts at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii07.pdf by the state population from the Census Bureau http://www.census.gov to find the total emissions for the state.

   Note: Use the steps in 2.1-2 to navigate through the U.S. Census Bureau's website.

2. Develop an emission factor by subtracting point source emissions from the total emissions and dividing by the state population found in step 1.

3. Distribute to the counties by multiplying the emission factor by the population for each county.

   Note: Use the steps in 2.1-5 to navigate through the U.S. Census Bureau's website.

Sub-Category 3.9: Rubber and Plastics

SCC: 2430000000

Follow these steps when calculating emissions from rubber and plastics activities:

1. Run a query to find the total of reported emissions and number of reported employees for all SIC's beginning with 30 using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb.

2. Calculate the emission factor by dividing the point source emissions by the reported employees.

3. Subtract the reported employment for SIC's beginning with 30 from total employment for each of the counties.

   Note: Use step 3.2-1 to navigate through the County Business Patterns.

4. Multiply the remaining number from above with the emission factor calculated in step 2.

Sub-Category 3.10: Miscellaneous Industrial Adhesives

SCC: 2440020000

Follow these steps when calculating emissions from industrial adhesives activities:

1. Using the guidance in the Air Pollutant Emission Trends at http://www.epa.gov/ttn/chief/trends, calculate an emission factor by finding the total National Emissions from Industrial Adhesives and divide by the National Manufacturing Employment from the U.S. Census Bureau's website http://www.census.gov.

   Note: As of the date of this SOP, the following steps will lead to emission trends data for industrial adhesives.

   a. Go to http://www.epa.gov/air/airtrends/aqtrnd03/
   b. Select "Appendix A –Data Tables"
   c. Search for industrial adhesives

   Note: As of the date of this SOP, the following steps will lead to National Manufacturing Employment.

   a. Go to http://www.census.gov

b. Select Economic Census
c. Now select “Businesses with paid employees”
d. Use the manufacturing number under “paid employees”

2. To avoid double calculating, run a query collecting sources reporting adhesives using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb. Subtract the reported employment from the total amount of manufacturing employment. The remaining number is the process rate.

Sub-Category 3.11: Commercial/Consumer Solvents

SCC: 2460100000, 2460200000, 2460400000, 2460500000, 2460600000, 2460800000, 2460900000

Follow these steps when calculating emissions from commercial/consumer solvent usage:

1. Using the EIIP, Volume 3, Chapter 5, Consumer, and Commercial Solvent Use at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii05.pdf, multiply the per capita factors for each of SCC codes by the population for each county from the U.S. Census Bureau’s website http://www.census.gov.

   Note: Use the steps in 2.1-5 to navigate through the U.S. Census Bureau’s website.

Emission Factors for Commercial/Consumer Solvents

Source Classification Codes	Product Category	Per Capita Emission Factor (lb VOC/person)
2460100000	Personal Care Products	2.32
2460200000	Household Products	0.79
2460400000	Automotive Aftermarket Products	1.36
2460500000	Coatings and Related Products	0.95
2460600000	Adhesives and Sealants	0.57
2460800000	FIFRA-Regulated Products	1.78
2460900000	Miscellaneous Products	0.07

Sub-Category 3.12: Asphalt Emulsions

SCC: 2461022000

Follow these steps when calculating emissions from asphalt emulsions:

1. To calculate the process rate, find the number of barrels of asphalt used for the state found at the State Energy Data website at http://www.eia.doe.gov/emeu/states/_seds_updates.html.

2. Obtain the amount of roadway miles for the state and county from the Indiana Department of Transportation’s, Division of Roadway Management Section.

3. Divide the county roadway miles by the state roadway miles and multiply by the total asphalt usage for the state found above in step 1.

4. Multiply the process rate by the default emission factor in the EIIP, Volume 3, Chapter 17, Asphalt Paving http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii17_apr2001.pdf.

Sub-Category 3.13: Pesticide Usage

SCC: 2461800000

Follow these steps when calculating emissions from pesticide usage:

1. Calculate pesticide usage by using a state specific emission factor. Develop the factor using a methodology that includes the retrieval of information of pesticides used, an emission factor for each pesticide used, a calculation about the inert ingredients in each pesticide, and an estimate of the amount of crop oil concentrate (an adjuvant used for the application of herbicides) used in the state of Indiana.

2. Find the amount of active ingredients for herbicides and insecticides applied to Indiana fields at the Indiana Agricultural Statistics Service at http://www.usda.gov/nass/pubs/agr02/acro02.htm.

3. Insert the numbers for both corn and soybeans to the Excel pesticide table found at K:OAQ_INV\Inv\pesticide.

4. Calculate the emission factor by adding the emissions from crop oil concentrates obtained in the pesticide Excel table, pesticides, and solvent carriers and then divide by the total number of acres of corn and soybeans in Indiana found at the National Agricultural Statistics Services, United States Department of Agriculture http://www.nass.usda.gov/QuickStats/.

5. Multiply the emission factor by the county-specific acreage for both corn and soybeans found at the National Agricultural Statistics Services, United States Department of Agriculture http://www.nass.usda.gov/QuickStats/.

Category 4: Petroleum Marketing

Follow these steps when calculating emissions for bulk terminals:

Sub-Category 4.1: Bulk Terminals

SCC: 2501050120

1. Find the amount of gasoline sold in Indiana at the Federal Highway Administration, U.S. Department of Transportation http://www.fhwa.dot.gov/policy/ohim/hs04/htm/mf21.htm.

2. Find the amount of gasoline sold statewide and by county using, the NAICS code 447-Gasoline Service Station from the U.S. Census Bureau's, Economic Census at http://www.census.gov/econ/census02/data/in/IN000_44.HTM#N447.

3. Run a query to find the amount of point source reported gasoline using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb and subtract from the amount sold statewide. Use this to allocate to each county.

4. Allocate the amount gasoline sold to each of the counties by dividing the amount of sales in each county by statewide sales and multiplying by the number of gallons sold statewide found above in step 1.

5. EPA guidance suggests that only 25% of all gasoline consumed goes through bulk plants. To calculate process rate, multiply each county by 25% to estimate the amount of fuel transferred through bulk terminals.

6. Multiply process rate by the emission factors in the table below:

Emission Factors	
Source	**Emission Factor (lb VOC/1000) gal**
Storage Tanks Breathing Loss	5.0
Storage Tank Working Loss - Filling	9.6
Storage Tank Working Loss - Emptying	3.8
Gasoline Loading Racks (Vapor balance controlled)	11.9 (0.3)
Total	30.3

7. Bulk terminals also have controls set forth in the Indiana rule (326 IAC 8-4). This rule says that any source of this type that is new after January 1, 1980 is required to make sure that any transfer between a tank and transport uses a submerged pipe vapor balance system. Using EPA's default rule effectiveness, multiply the number in step 2 by the Control Efficiency (CE) 38%, a Rule Effectiveness (RE) of 80%, and a Rule Penetration (RP) of 13%, i.e. process rate X emission factor X (1-(CE x RE x RP)) X 1 ton/2000 lb = VOC tons.

Sub-Category 4.2: Portable Fuel Containers

SCC: 2501011011, 2501011012, 2501011016, 2501012011, 2501012012, 2501012016

Follow these steps when calculating emissions for portable fuel containers:

1. Calculate the emissions for Commercial and Residential gas cans by using the method developed by the California Environmental Protection Agency's document Public Meeting to Consider Approval of California's Portable Gasoline-Container Emissions Inventory. Use the excel spreadsheet found at K:\OAQ_INV\Inv\Area Source\Gasoline.zip to calculate the emissions for permeation, diurnal, and transport. Both the Spillage and Vapor losses are estimated in the nonroad emissions inventory by EPA models.

2. Using the survey results below in Table 1, estimate the number of fuel containers in the state for residential categories. The calculations are set up in an excel spreadsheet at K:\OAQ_INV\Inv\Area Source\ Gasoline.zip\250101\GasCans.xls, insert the number of occupied housing, from the U.S. Census Bureau's website at http://www.census.gov/, in the space marked "households".

   Note: As of the data of this SOP, the following steps will lead to number of households in Indiana.

   a. Go to http://www.census.gov/
   b. On the left hand side select American Fact finder
   c. Now select housing
   d. Under "Occupancy Status", select occupies housing units
   e. Now use the drop down menu and select Indiana

Table 1

Residential Survey Results	
Percentage of households with at least one gas can	46%
Number of gas cans per household	1.8
Percentage of plastic cans/metal cans	76% / 24%
Weighted average gas can capacity (gal)	2.34
Percentage of gas cans stored with fuel	70%
Weighted average stored fuel volume (% of capacity)	49%

Percentage of all gas cans that are plastic and stored open/closed	23% / 53%
Percentage of all gas cans that are metal and stored open/closed	11% / 13%
Percent of all cans stored open/closed	34% / 66%

3. Using the survey results below in Table 2, estimate the number of fuel containers for commercial categories for the state. Do this by using the commercial population based on the number of identified businesses in Table 3 and insert into the excel spreadsheet at K:\OAQ_INV\Inv\Area Source\ Gasoline.zip\250101\GasCans.xls.

Table 2

Commercial Survey Results	
Percentage of businesses with at least one gas can	80%
Number of gas cans per business	6.9
Percentage of plastic cans/metal cans	72% / 28%
Weighted average gas can capacity (gal)	3.43
Weighted average stored fuel volume (% of capacity)	49%
Percentage of all gas cans that are plastic and stored open/closed	39% / 33%
Percentage of all gas cans that are metal and stored open/closed	10% / 18%
Percent of all cans stored open/closed	49% / 51%

Table 3

Category	NAICS
Agricultural	115
Automotive Club and Towing Services	48841
Service Stations	8111
Lawn and Garden Maintenance Services	81141
General Contractors	23
Construction and Rental Yards	5324
Landscaping Services	561730

4. Calculate permeable emissions separately for both residential and commercial by using the emission rates given in the California document. Use 1.57g/gal/day for plastic containers and 0.6g/gal/day for metal containers. Insert the numbers for both residential and commercial into the excel spreadsheet at K:\OAQ_INV\Inv\Area Source\ Gasoline.zip\250101\GasCans.xls.

5. Calculate diurnal emissions by inserting the numbers for both residential and commercial into the excel spreadsheet at K:\OAQ_INV\Inv\Area Source\ Gasoline.zip\250101\GasCans.xls.

6. Calculate transport spillage emissions by inserting the numbers for both residential and commercial into the excel spreadsheet at K:\OAQ_INV\Inv\Area Source\ Gasoline.zip\250101\GasCans.xls

Sub-Category 4.3: Service Station Tank Loading or Tank Truck Unloading (Stage 1)

SCC: 2501060052 (uncontrolled), 2501060053 (controlled)

Follow these steps when calculating emissions from tank loading and unloading

1. Find the amount of gasoline sold in Indiana at the Federal Highway Administration, U.S. Department of Transportation http://www.fhwa.dot.gov/policy/ohim/hs04/htm/mf21.htm.

2. Find the amount of gasoline sold statewide and county wide by using the NAICS code 447-Gasoline Service Station from the U.S. Census Bureau's, Economic Census at http://www.census.gov/econ/census02/data/in/IN000_44.HTM#N447.

3. Run a query to find the amount of point source reported gasoline using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb and subtract from the amount sold statewide. Use this to allocate to each county.

4. Allocate the amount sold to each of the counties by dividing the amount of sales in each county by statewide sales and multiplying by the number of gallons sold statewide found above in step 1.

5. Find the amount of gasoline tanks from the Underground Storage Tank data files from the Office of Land Quality, Indiana Department of Environmental Management http://www.in.gov/idem/programs/land/ust/ust.html.

6. Now copy the data into an Excel spreadsheet. Filter finding the tanks that have only gasoline. Also filter out the tanks that are "permanently out of service", "suspended per inspection", and "unregulated".

7. Using the Petroleum Sources Applicability Rule 326 IAC 8-4-1, filter out the tanks that are located in Clark, Boone, Dearborn, Elkhart, Floyd, Hamilton, Hancock, Harrison, Hendricks, Johnson, Lake, Marion, Morgan, Porter, Saint Joseph, and Shelby counties.

8. To find the amount of balanced tanks in Indiana, use the total of gasoline tanks found in step 7 and divide by the number of tanks that constructed after 1985 through current year. Use the spreadsheet created in step 7 and filter out the tanks that constructed prior to 1985.

9. Now apply the percentage found in step 8 to the amount of gasoline found in each county.

10. Apply the controlled emission factor to only those counties identified in 326 IAC 8-4, i.e. Boone, Clark, Dearborn, Elkhart, Hamilton, Hancock, Harrison, Hendricks, Johnson, Lake, Marion, Morgan, Porter, Saint Joseph, and Shelby. Use the emission factors for stage 1 controlled and uncontrolled in the EIIP, Volume 3, Chapter 11, Gasoline Marketing (Stage 1 and Stage 2) http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii11_apr2001.pdf.

Sub-Category 4.4: Vehicle Fueling (Stage II) – Vapor Displacement

SCC: 2501060101 (uncontrolled), 2501060102 (controlled)

Follow these steps when calculating emissions from vehicle fueling – Vapor Displacement:

1. Find the amount of gasoline sold in Indiana at the Federal Highway Administration, U.S. Department of Transportation http://www.fhwa.dot.gov/policy/ohim/hs04/htm/mf21.htm.

2. Find the amount of gasoline sold statewide and by county using the NAICS code 447-Gasoline Service Station from the U.S. Census Bureau's, Economic Census at http://www.census.gov/econ/census02/data/in/IN000_44.HTM#N447.

3. Allocate the amount sold to each of the counties by dividing the amount of sales in each county by statewide sales and multiplying by the number of gallons sold statewide found above in step 1.

4. Calculate an emission factor using the input files supplied from the mobile model. Table 1 and Table 2 show examples of how the emission factors for January and July for the Southern Counties were calculated. By using these two months, the other months are distributed. Use the average of all months for the emission factor for the Southern counties. Use the same methodology for the Northern counties, Central Counties, Clark/Floyd, and Lake/Porter.

Table 1

January Run for Southern Counties

VTYPE	GM_MILE	MILES	MPG	VMT	G/GAL		Month	Factor
1	0.0628	29.4642	23.89	0.463793	0.322719		1	1.01
2	0.1058	35.2923	18.77	0.070491	0.009868		2	1.14
3	0.1058	35.2923	18.77	0.234672	0.109364		3	1.28
4	0.1486	34.0851	14.31	0.071379	0.010834		4	1.41
5	0.1486	34.0851	14.31	0.032825	0.002291		5	1.55
6	0.2152	35.8919	9.88	0.028896	0.001775		6	1.69
7	0.2342	32.3617	9.08	0.001027	2.24E-06		7	1.82
8	0.2465	19.9098	8.63	0.000522	5.8E-07		8	1.69
9	0.2719	27.6093	7.82	0.001164	2.88E-06		9	1.55
10	0.2733	27.4686	7.78	0.002489	1.32E-05		10	1.41
11	0.2972	24.3758	7.15	0.001132	2.72E-06		11	1.28
12	0.3169	23.6257	6.71	0.000004	3.4E-11		12	1.14
25	0.3421	27.2301	6.22	0.000496	5.23E-07		Sum	16.97
					0.456873	g/gal	Average	1.41
					1.007222	lb/E3gal		

Table 2
July Run for Southern Counties

VTYPE	GM_MILE	MILES	MPG	VMT	G/GAL	
1	0.1144	29.1752	23.9	0.456768	0.570447	
2	0.1955	34.8826	18.75	0.071404	0.018689	
3	0.1955	34.8826	18.75	0.237712	0.207133	
4	0.2882	33.944	14.3	0.072838	0.021865	
5	0.2882	33.944	14.3	0.033496	0.004624	
6	0.4164	35.8288	9.9	0.029201	0.003515	
7	0.4529	32.4716	9.1	0.001038	4.44E-06	
8	0.4763	19.6757	8.66	0.000509	1.07E-06	
9	0.5264	27.4602	7.83	0.00116	5.55E-06	
10	0.5283	27.3328	7.8	0.002482	2.54E-05	
11	0.5749	24.2458	7.17	0.001122	5.19E-06	
12	0.6128	23.3718	6.73	0.000004	6.6E-11	
25	0.6629	27.2301	6.22	0.000485	9.7E-07	
					0.826316	g/gal
					1.821697	lb/E3gal

5. Multiply the process rate in step 4 by the emission factor found in the mobile model.

Sub-Category 4.5: Vehicle Fueling (Stage II) – Spillage

SCC: 2501060103

Follow these steps when calculating emissions from vehicle fueling – Spillage:

1. Find the amount of gasoline sold in Indiana at the Federal Highway Administration, U.S. Department of Transportation http://www.fhwa.dot.gov/policy/ohim/hs04/htm/mf21.htm.

2. Find the amount of gasoline sold statewide and by county using the NAICS code 447-Gasoline Service Station from the U.S. Census Bureau's, Economic Census at http://www.census.gov/econ/census02/data/in/IN000_44.HTM#N447.

3. Allocate the amount sold to each of the counties by dividing the amount of sales in each county by statewide sales and multiplying by the number of gallons sold statewide found above in step 1.

4. Apply the emission factor 0.7 lb VOC/1000 gallons in AP-42, Fifth Edition, Volume 1, Chapter 5, Petroleum Industry, Transportation, and Marketing of Petroleum Liquids http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s02.pdf to the process rate found in step 4.

Sub-Category 4.6: Underground Tank Breathing

SCC: 2501060200

Follow these steps when calculating emissions from underground tank breathing:

1. Find the amount of gasoline sold in Indiana at the Federal Highway Administration, U.S. Department of Transportation http://www.fhwa.dot.gov/policy/ohim/hs04/htm/mf21.htm.

2. Find the amount of gasoline sold statewide and by county using the NAICS code 447-Gasoline Service Station from the U.S. Census Bureau's, Economic Census at http://www.census.gov/econ/census02/data/in/IN000_44.HTM#N447.

3. Allocate the amount sold to each of the counties by dividing the amount of sales in each county by statewide sales and multiplying by the number of gallons sold statewide found above in step 1.

4. Apply the emission factor 1.0 lb VOC/1000 gallons in AP-42, Fifth Edition, Volume 1, Chapter 5, Petroleum Industry, Transportation, and Marketing of Petroleum Liquids http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s02.pdf to the process rate found in step 4.

Sub-Category 4.7: Tank Trucks in Transit

SCC: 2505030120

Follow these steps when calculating emissions from tank trucks in transit:

1. Find the amount of gasoline sold in Indiana at the Federal Highway Administration, U.S. Department of Transportation http://www.fhwa.dot.gov/policy/ohim/hs04/htm/mf21.htm.

2. Find the amount of gasoline sold statewide and by county using the NAICS code 447-Gasoline Service Station from the U.S. Census Bureau's, Economic Census at http://www.census.gov/econ/census02/data/in/IN000_44.HTM#N447.

3. Allocate the amount sold to each of the counties by dividing the amount of sales in each county by statewide sales and multiplying by the number of gallons sold statewide found above in step 1.

4. Using the guidance in the EIIP, Volume 3, Chapter 11, Gasoline Marketing (Stage I and State II) at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/iii11_apr2001.pdf), multiply the activity rate 1.25 by the amount sold per county found in step 4.

5. Now multiply the process rate found in step 5 by the emission factor .06 lb VOC/gallon transported using the EIIP guidance above.

Category 5: Waste Management Practices

Sub-Category 5.1: Solid Waste Incineration

5.1.1: Industrial Solid Waste Incineration

SCC: 2601010000

Follow these steps when calculating emissions from industrial solid waste incineration:

1. Find the number of manufacturing employees, NAICS code 31, for each county using the County Business Patterns at the U.S. Census Bureau's website http://censtats.census.gov/cgi-bin/cbpnaic/cbpsel.pl.

   Note: Use the steps in 3.2-1 to navigate through the county business patterns.

2. Multiply the county manufacturing employment by the default fuel-loading factor 420 tons / 1,000 manufacturing employees.

3. Multiply the process rate in step 2 by AP-42, Fifth Edition, Volume 1, Chapter 2-1.12, Solid Waste Disposal at http://www.epa.gov/ttn/chief/ap42/ch02/index.html.

5.1.2: Commercial Solid Waste Incineration

SCC: 2601020000

Follow these steps when calculating emissions from commercial solid waste incineration:

1. Find the population for each county at the U.S. Census Bureau's website http://www.census.gov/.

   Note: Use steps 2.1-5 to navigate through the U.S. Census Bureau's website.

2. Next find the default factor of .65lb/person/day from U.S. EPA Municipal Solid Waste Report http://www.epa.gov/epaoswer/non-hw/muncpl/msw99.htm.

3. Find the percent of commercial solid waste from the U.S. EPA Municipal Solid Waste Report above.

4. Now, calculate the process rate for commercial solid waste incineration by multiplying population by the default factor of .65lb/person/day by the percent of commercial solid waste and number of days in a year.

5. Multiply the process rate in step 4 by AP-42, Fifth Edition, Volume 1, Chapter 2-1.12, Solid Waste Disposal at http://www.epa.gov/ttn/chief/ap42/ch02/index.html.

5.1.3: Residential Solid Waste Incineration

SCC: 2601030000

Follow these steps when calculating emissions from residential solid waste incineration:

1. Find the population for each county at the U.S. Census Bureau's website http://www.census.gov/.

   Note: Use step 2.1-5 to navigate through the U.S. Census Bureau's website.

2. Next find the default factor of .65lb/person/day from U.S. EPA Municipal Solid Waste Report http://www.epa.gov/epaoswer/non-hw/muncpl/msw99.htm.

3. Find the percent of residential solid waste from the U.S. EPA Municipal Solid Waste Report above.

4. Now, calculate the process rate for residential solid waste incineration by multiplying population by the default factor of .65lb/person/day by the percent of commercial solid waste and number of days in a year.

5. Multiply the process rate in step 4 by AP-42, Fifth Edition, Volume 1, Chapter 2-1.12, Solid Waste Disposal at http://www.epa.gov/ttn/chief/ap42/ch02/index.html.

Sub-Category 5.2: Residential Open Burning

5.2.1: Leaf and Brush Burning

SCC: 2610000100 and 2610000400

Follow theses step when calculating emissions from leaf and brush burning:

1. Find a per capita factor for leaf burning and a per capita for brush burning by using the U.S. EPA's Solid Waste Report at http://www.epa.gov/epaoswer/non-hw/muncpl/msw99.htm.

2. Allocate the amount burned by adjusting the per capita factor for leaves at 25% and for brush at 25%. Of the total waste generated only 28% burns.

3. Once all the percentages from above are calculated, multiply the adjusted per capita factor by the rural population for each county from the U.S. Census Bureau at http://www.census.gov/

   Note: As of the data of this SOP, the following steps will lead to county rural population.

   a. Go to http://www.census.gov/
   b. On the left hand side, select American Fact Finder
   c. Select data sets
   d. Detailed tables
   e. County
   f. Indiana
   g. All counties

4 Use the table below to adjust the amount of waste generated to account for the percentage of forest in each county. The percentages come from a document from the United States Department of Agriculture at http://ncrs.fs.fed.us/pubs/rb/rb_nc253b.pdf.

Percent Forested Acres per County	Adjusted for Yard Waste Generated
< 10%	0% generated
>= 10%, and < 50%	50% generated
>= 50%	100% generated

5. Now, multiply the amount of leaves and brush by the emission factors found in AP-42, Fifth Edition, Volume 1, Chapter 2, Solid Waste Disposal, Table 2.5-5, and Table 2.5-6 at http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s05.pdf.

5.2.2: Residential Waste Incineration

SCC: 2610030000

Follow these steps when calculating emissions from for residential waste incineration:

1. Find a per capita factor for residential waste incineration by using the U.S. EPA's Solid Waste Report at http://www.epa.gov/epaoswer/non-hw/muncpl/pubs/mswchar05.pdf.

2. Using the Solid Waste Report above, subtract the percentage of recycled and composted material from the per capita factor above.

3. Now, subtract the percentages of combustibles i.e. glass, metal, yard trimmings, and other waste.

4. Using a document from EPA, it states that only 28% of waste generated by rural population burns and of that percent, 49% is actually combusted. Using this information multiply the per capita factor by 0.28 and then multiply that number by 0.49 actually burned in rural counties.

5. Once all the percentages are calculated, multiply the adjusted per capita factor by the rural population for each county from the U.S. Census Bureau at http://www.census.gov/.

   Note: Use steps 5.2.1-3 to find county rural population.

6. Calculate the amount of residential waste by the emission factors in the EIIP, Volume 3, Chapter 16, Open Burning at http://www.epa.gov/ttn/chief/eiip/techreport/volume03/index.html.

Sub-Category 5.3: Public Owned Treatment Works (POTW's)

SCC: 2630020000

Follow these steps when calculating emissions from POTW's:

1. To calculate the amount of annual flow for public owned treatment works, obtain the amount of monthly flow rate for each county. This is data is supplied by the Office of Water Quality. To calculate for annual flow multiply the monthly flow by the default of 0.16 that represents the amount of industrial flow.

2. Calculate the process rate above by the emission factors in FIRE 6.25 using the SCC code 2630020000.

Sub-Category 5.4: Treatment, Storage, and Disposal Facilities

SCC: 2640000004

Follow these steps when calculating emissions from treatment, storage, and disposal facilities:

1. Obtain a list of treatment facilities and the amount of ignitable waste from each facility from IDEM's Office of Land Quality.

2. Using the list of facilities from step 1, run a query using the ACCESS data tables at K:\OAQ_INV\Steptool\Stptl_02.mdb to obtain the amount of ignitable waste reported to IDEM's Office of Air Quality.

3. Compare the two lists obtained in step 1 and step 2, for each facility subtract any quantity reported to OAQ from the quantity reported to OLQ. Do this in order to avoid double counting quantities reported to both offices. Combine the quantities reported from facilities within the same counties. Use these quantities as the process rate for each county.

4. Multiply the process rate above with the combined emission factor in the table below:

Emission Source	Emission Factor in AP-42 (lb VOC/Ton)	Emission Factor Used (lb VOC/Ton)
Storage Tank Vent	0.004-0.09	0.09
Spillage (filling)	0.20	0.20
Loading (filling)	0.00024-1.42	1.42
Spillage (emptying)	0.20	0.20
Loading (emptying)	0.00024-1.42	1.42
Combined Emission Factor		**3.33**

Category 6: Submit Data to EPA

Submit data in a format that is acceptable to EPA. At the present time the format is the National Emission Inventory (NEI).

6. Standards and checklists

The Emission Reporting program does not have any checklist for the Area Source Inventory at this time. The Emission Group does this electronically through an excel spreadsheet that is created when needed.

7. Records Management

The Area Source Inventory files are kept electronically at K:\OAQ_INV\Inv\Area Source.

The Branch Contact for the Air Programs Branch and the Section contact for the Technical Support and Modeling Section will keep copies of the SOPs for the Technical Support and Modeling Section to be referenced as needed. An electronic copy will also be available on K:\OAQ_INV\SOPs.

8. Quality Assurance / Quality Control
Comparisons are made against the emissions estimates made by The U.S. EPA in the NEI.

9. Continuous Improvement Cycle
A periodic review will be completed per updates and changes made to the EIIP.

10. References
The Area Source Inventory is a requirement of 40 CFR Part 51 Subpart A - Emission Inventory Reporting Requirements.

11. History of Revisions

Date Month/day/year	Revision Number	Description
02/27/2008	1	Revised using new SOP template.

12. Appendices
None

APPENDIX H

Lake Michigan Air Directors Consortium Emission Estimates Technical Support Document

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Regional Air Quality Analyses for Ozone, $PM_{2.5}$, and Regional Haze:

Final Technical Support Document

April 25, 2008

States of Illinois, Indiana, Michigan, Ohio, and Wisconsin

Table of Contents

EXECUTIVE SUMMARY

States in the upper Midwest face a number of air quality challenges. More than 50 counties are currently classified as nonattainment for the 8-hour ozone standard and 60 for the fine particle ($PM_{2.5}$) standard (1997 versions). A map of these nonattainment areas is provided in the figure below. In addition, visibility impairment due to regional haze is a problem in the larger national parks and wilderness areas (i.e., Class I areas). There are 156 Class I areas in the U.S., including two in northern Michigan.

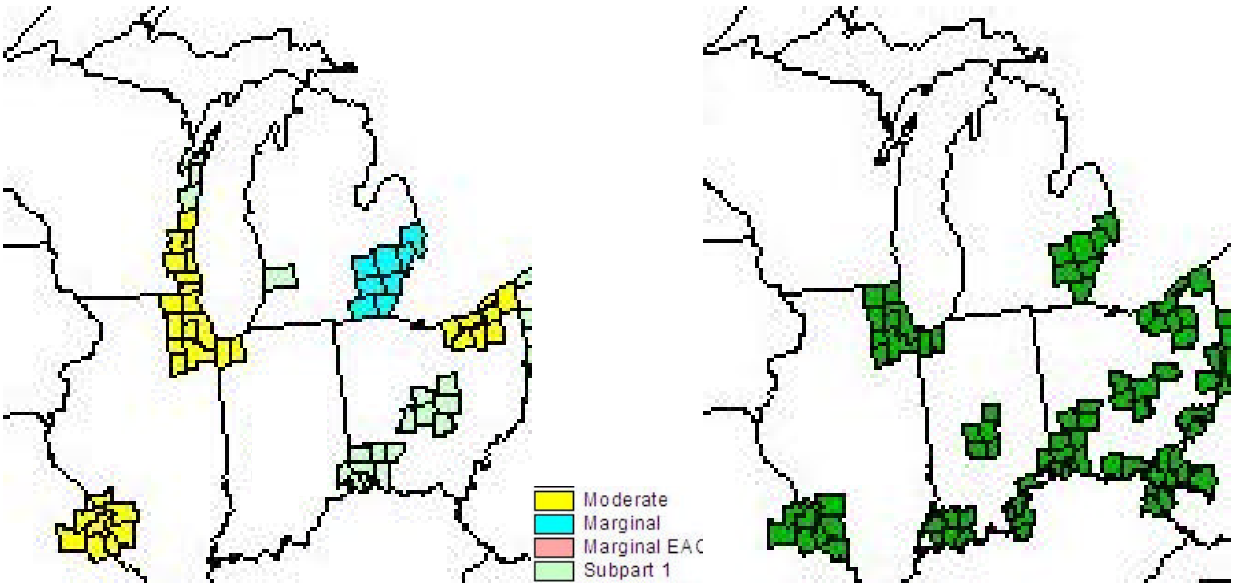


Figure i. Current nonattainment counties for ozone (left) and $PM_{2.5}$ (right)

To support the development of State Implementation Plans (SIPs) for ozone, $PM_{2.5}$, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin, technical analyses were conducted by the Lake Michigan Air Directors Consortium (LADCO), its member states, and various contractors. The analyses include preparation of regional emissions inventories and meteorological data, evaluation and application of regional chemical transport models, and collection and analysis of ambient monitoring data.

Monitoring data were analyzed to produce a conceptual understanding of the air quality problems. Key findings of the analyses include:

Ozone

- Current monitoring data (2005-2007) show about 20 sites in violation of the 8-hour ozone standard of 85 parts per billion (ppb). Historical ozone data show a steady downward trend over the past 15 years, especially since 2001-2003, due likely to federal and state emission control programs.

- Ozone concentrations are strongly influenced by meteorological conditions, with more high ozone days and higher ozone levels during summers with above normal temperatures.

- Inter- and intra-regional transport of ozone and ozone precursors affects many portions of the five states, and is the principal cause of nonattainment in some areas far from population or industrial centers.

$PM_{2.5}$

- Current monitoring data (2005-2007) show 30 sites in violation of the annual $PM_{2.5}$ standard of 15 ug/m^3. Nonattainment sites are characterized by an elevated regional background (about 12 – 14 ug/m^3) and a significant local (urban) increment (about 2 – 3 ug/m^3). Historical $PM_{2.5}$ data show a slight downward trend since deployment of the $PM_{2.5}$ monitoring network in 1999.

- $PM_{2.5}$ concentrations are also influenced by meteorology, but the relationship is more complex and less well understood compared to ozone.

- On an annual average basis, $PM_{2.5}$ chemical composition consists mostly of sulfate, nitrate, and organic carbon in similar proportions.

Haze

- Current monitoring data (2000-2004) show visibility levels in the Class I areas in northern Michigan are on the order of 22 – 24 deciviews. The goal of EPA's visibility program is to achieve natural conditions, which is about 12 deciviews for these Class I areas, by the year 2064.

- Visibility impairment is dominated by sulfate and nitrate.

Air quality models were applied to support the regional planning efforts. Two base years were used in the modeling analyses: 2002 and 2005. Basecase modeling was conducted to evaluate model performance (i.e., assess the model's ability to reproduce observed concentrations). This exercise was intended to build confidence in the model prior to its use in examining control strategies. Model performance for ozone and $PM_{2.5}$ was found to be generally acceptable.

Future year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Based on the modeling and other supplemental analyses, the following general conclusions can be made:

- Existing controls are expected to produce significant improvement in ozone and $PM_{2.5}$ concentrations and visibility levels.

- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).

- Modeling suggests that most sites are expected to meet the current 8-hour ozone standard by the applicable attainment date, except for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.

- Modeling suggests that most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.

  The regional modeling for $PM_{2.5}$ does not include air quality benefits expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$.

- These findings of residual nonattainment for ozone and $PM_{2.5}$ are supported by current (2005 – 2007) monitoring data which show significant nonattainment in the region (e.g., peak ozone design values on the order of 90 – 93 ppb, and peak $PM_{2.5}$ design values on the order of 16 - 17 ug/m^3). It is unlikely that sufficient emission reductions will occur in the next couple of years to provide for attainment at all sites.

- Attainment at most sites by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). If either of these conditions is not met, then attainment may be less likely.

- Modeling suggests that the new $PM_{2.5}$ 24-hour standard and the new lower ozone standard will not be met at several sites, even by 2018, with existing controls.

- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018 based on existing controls, including those in northern Michigan and some in the northeastern U.S. Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018. These results, along with information on the costs of compliance, time necessary for compliance, energy and non air quality environmental impacts of compliance, and remaining useful life of existing sources, should be considered by the states in setting reasonable progress goals for regional haze.

Section 1.0 Introduction

This Technical Support Document summarizes the final air quality analyses conducted by the Lake Michigan Directors Consortium (LADCO)[1] and its contractors to support the development of State Implementation Plans (SIPs) for ozone, fine particles ($PM_{2.5}$), and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin. The analyses include preparation of regional emissions inventories and meteorological modeling data for two base years (2002 and 2005), evaluation and application of regional chemical transport models, and analysis of ambient monitoring data.

Two aspects of the analyses should be emphasized. First, a regional, multi-pollutant approach was taken in addressing ozone, $PM_{2.5}$, and haze for technical reasons (e.g., commonality in precursors, emission sources, atmospheric processes, transport influences, and geographic areas of concern), and practical reasons (e.g., more efficient use of program resources). Furthermore, EPA has consistently encouraged multi-pollutant planning in its rule for the haze program (64 FR 35719), and its implementation guidance for ozone (70 FR 71663) and $PM_{2.5}$ (72 FR 20609). Second, a weight-of-evidence approach was taken in considering the results of the various analyses (i.e., two sets of modeling results -- one for a 2002 base year and one for a 2005 base year -- and ambient data analyses) in order to provide a more robust assessment of expected future year air quality.

The report is organized in the following sections. This Introduction provides an overview of regulatory requirements and background information on regional planning. Section 2 reviews the ambient monitoring data and presents a conceptual model of ozone, $PM_{2.5}$, and haze for the region. Section 3 discusses the air quality modeling analyses, including development of the key model inputs (emissions inventory and meteorological data), and basecase model performance evaluation. A modeled attainment demonstration for ozone and $PM_{2.5}$ is presented in Section 4, along with relevant data analyses considered as part of the weight-of-evidence determination. Section 5 documents the reasonable progress assessment for regional haze, along with relevant data analyses considered as part of the weight-of-evidence determination. Finally, key study findings are reviewed and summarized in Section 6.

1.1 SIP Requirements

For ozone, EPA promulgated designations on April 15, 2004 (69 FR 23858, April 30, 2004). In the 5-state region, more than 100 counties were designated as nonattainment.[2] The designations became effective on June 15, 2004. SIPs for ozone were due no later than three years from the effective date of the nonattainment designations (i.e., by June 2007). The attainment date for ozone varies as a function of nonattainment classification. For the region, the attainment dates are either June 2007 (marginal nonattainment areas), June 2009 (basic nonattainment areas), or June 2010 (moderate nonattainment areas).

[1] A sub-entity of LADCO, known as the Midwest Regional Planning Organization (MRPO), is responsible for the regional haze activities of the multi-state organization.

[2] Based on more recent air quality data, many counties in Indiana, Michigan, and Ohio were subsequently redesignated as attainment. As of December 31, 2007, there are 53 counties designated as nonattainment in the region.

For $PM_{2.5}$, EPA promulgated designations on December 17, 2004 (70 FR 944, January 5, 2005). In the 5-state region, 70 counties were designated as nonattainment.[3] The designations became effective on April 5, 2005. SIPs for $PM_{2.5}$ are due no later than three years from the effective date of the nonattainment designations (per section 172(b) of the Clean Air Act) (i.e., by April 2008) and for haze no later than three years after the date on which the Administrator promulgated the $PM_{2.5}$ designations (per the Omnibus Appropriations Act of 2004) (i.e., by December 2007). The applicable attainment date for $PM_{2.5}$ nonattainment areas is five years from the date of the nonattainment designation (i.e., by April 2010).

For haze, the Clean Air Act sets "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." There are 156 Class I areas, including two in northern Michigan: Isle Royale National Park and Seney National Wildlife Refuge[4]. EPA's visibility rule (64 FR 35714, July 1, 1999) requires reasonable progress in achieving "natural conditions" by the year 2064. As noted above, the first regional haze SIP was due in December 2007 and must address the initial 10-year implementation period (i.e., reasonable progress by the year 2018). SIP requirements (pursuant to 40 CFR 51.308(d)) include setting reasonable progress goals, determining baseline conditions, determining natural conditions, providing a long-term control strategy, providing a monitoring strategy (air quality and emissions), and establishing BART emissions limitations and associated compliance schedule.

1.2 Organization

LADCO was established by the States of Illinois, Indiana, Michigan, and Wisconsin in 1989. The four states and EPA signed a Memorandum of Agreement (MOA) that initiated the Lake Michigan Ozone Study (LMOS) and identified LADCO as the organization to oversee the study. Additional MOAs were signed by the States in 1991 (to establish the Lake Michigan Ozone Control Program), January 2000 (to broaden LADCO's responsibilities), and June 2004 (to update LADCO's mission and reaffirm the commitment to regional planning). In March 2004, Ohio joined LADCO. LADCO consists of a Board of Directors (i.e., the State Air Directors), a technical staff, and various workgroups. The main purposes of LADCO are to provide technical assessments for and assistance to its member states, and to provide a forum for its member states to discuss regional air quality issues.

MRPO is a similar entity led by the five LADCO States and involves the federally recognized tribes in Michigan and Wisconsin, EPA, and Federal Land Managers (i.e., National Park Service, U.S. Fish & Wildlife Agency, and U.S. Forest Service). In October 2000, the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin signed an MOA that established the MRPO. An operating principles document for MRPO, which describe the roles and responsibilities of states, tribes, federal agencies, and stakeholders, was issued in March 2001. MRPO has a similar purpose as LADCO, but is focused on visibility impairment due to regional haze in the Federal Class I areas located inside the borders of the five states, and the impact of emissions from the five states on visibility impairment due to regional haze in the Federal Class I areas located outside the borders of the five states. MRPO works cooperatively with the Regional Planning Organizations (RPOs) representing other parts of the country. The RPOs sponsored several

[3] USEPA subsequently adjusted the final designations, which resulted in 63 counties in the region being designated as nonattainment (70 FR 19844, April 15, 2005).

[4] Although Rainbow Lake in northern Wisconsin is also a Class I area, the visibility rule does not apply because the Federal Land Manager determined that visibility is not an air quality related value there.

joint projects and, with assistance by EPA, maintain regular contact on technical and policy matters.

1.3 Technical Work: Overview

To ensure the reliability and effectiveness of its planning process, LADCO has made data collection and analysis a priority. More than $7M in RPO grant funds were used for special purpose monitoring, preparing and improving emissions inventories, and conducting air quality analyses[5]. An overview of the technical work is provided below.

Monitoring: Numerous monitoring projects were conducted to supplement on-going state and local air pollution monitoring. These projects include rural monitoring (e.g., comprehensive sampling in the Seney National Wildlife Refuge and in Bondville, IL); urban monitoring (e.g., continuation of the St. Louis Supersite); aloft (aircraft) measurements; regional ammonia monitoring; and organic speciation sampling in Seney, Bondville, and five urban areas.

Emissions: Baseyear emissions inventories were prepared for 2002 and 2005. States provided point source and area source emissions data, and MOBILE6 input files and mobile source activity data. LADCO and its contractors developed the emissions data for other source categories (e.g., select nonroad sources, ammonia, fires, and biogenics) and processed the data for input into an air quality model. To support control strategy modeling, future year inventories were prepared. The future years of interest include 2008 (planning year to address the 2009 attainment year for basic ozone nonattainment ares), 2009 (planning year to address the 2010 attainment year for $PM_{2.5}$ and moderate ozone nonattainment areas), 2012 (planning to address a 2013 alternative attainment date), and 2018 (first milestone year for regional haze).

Air Quality Analyses: The weight-of-evidence approach relies on data analysis and modeling. Air quality data analyses were used to provide both a conceptual model (i.e., a qualitative description of the ozone, $PM_{2.5}$, and regional haze problems) and supplemental information for the attainment demonstration. Given uncertainties in emissions inventories and modeling, especially for $PM_{2.5}$, these data analyses are a necessary part of the overall technical support.

Modeling includes baseyear analyses for 2002 and 2005 to evaluate model performance and future year strategy analyses to assess candidate control strategies. The analyses were conducted in accordance with EPA's modeling guidelines (EPA, 2007a). The PM/haze modeling covers the full calendar year (2002 and 2005) for an eastern U.S. 36 km domain, while the ozone modeling focuses on the summer period (2002 and 2005) for a Midwest 12 km subdomain. The same model (CAMx) was used for ozone, $PM_{2.5}$, and regional haze.

[5] Since 1999, MRPO has received almost $10M in RPO grant funds from USEPA.

Section 2.0 Ambient Data Analyses

An extensive network of air quality monitors in the 5-state region provides data for ozone (and its precursors), $PM_{2.5}$ (both total mass and individual chemical species), and visibility. These data are used to determine attainment/nonattainment designations, support SIP development, and provide air quality information to public (see, for example, www.airnow.gov).

Analyses of the data were conducted to produce a conceptual model, which is a qualitative summary of the physical, chemical, and meteorological processes that control the formation and distribution of pollutants in a given region. This section reviews the relevant data analyses and describes our understanding of ozone, $PM_{2.5,}$ and regional haze with respect to current conditions, data variability (spatial, temporal, and chemical), influence of meteorology (including transport patterns), precursor sensitivity, and source culpability.

2.1 Ozone

In 1979, EPA adopted an ozone standard of 0.12 ppm, averaged over a 1-hour period. This standard is attained when the number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is equal to or less than 1.0, averaged over a 3-year period, which generally reflects a design value (i.e., the 4th highest daily 1-hour value over a 3-year period) less than 0.12 ppm.

In 1997, EPA tightened the ozone standard to 0.08 ppm, averaged over an 8-hour period[6]. The standard is attained if the 3-year average of the 4th-highest daily maximum 8-hour average ozone concentrations (i.e., the design value) measured at each monitor within an area is less than 0.08 ppm (or 85 ppb).

Current Conditions: A map of the 8-hour ozone design values at each monitoring site in the region for the 3-year period 2005-2007 is shown in Figure 1. The "hotter" colors represent higher concentrations, where yellow and orange dots represent sites with design values above the standard. Currently, there are 19 sites in violation of the 8-hour ozone NAAQS in the 5-state region, including sites in the Lake Michigan area, Detroit, Cleveland, Cincinnati, and Columbus.

Table 1 provides the 4th-highest daily 8-hour ozone values and the associated design values since 2001 for several high monitoring sites throughout the region.

[6] On March 12, 2008, USEPA further tightened the 8-hour ozone standard to increase public health protection and prevent environmental damage from ground-level ozone. USEPA set the primary (health) standard and secondary (welfare) standard at the same level: 0.075 ppm (75 ppb), averaged over an 8-hour period.

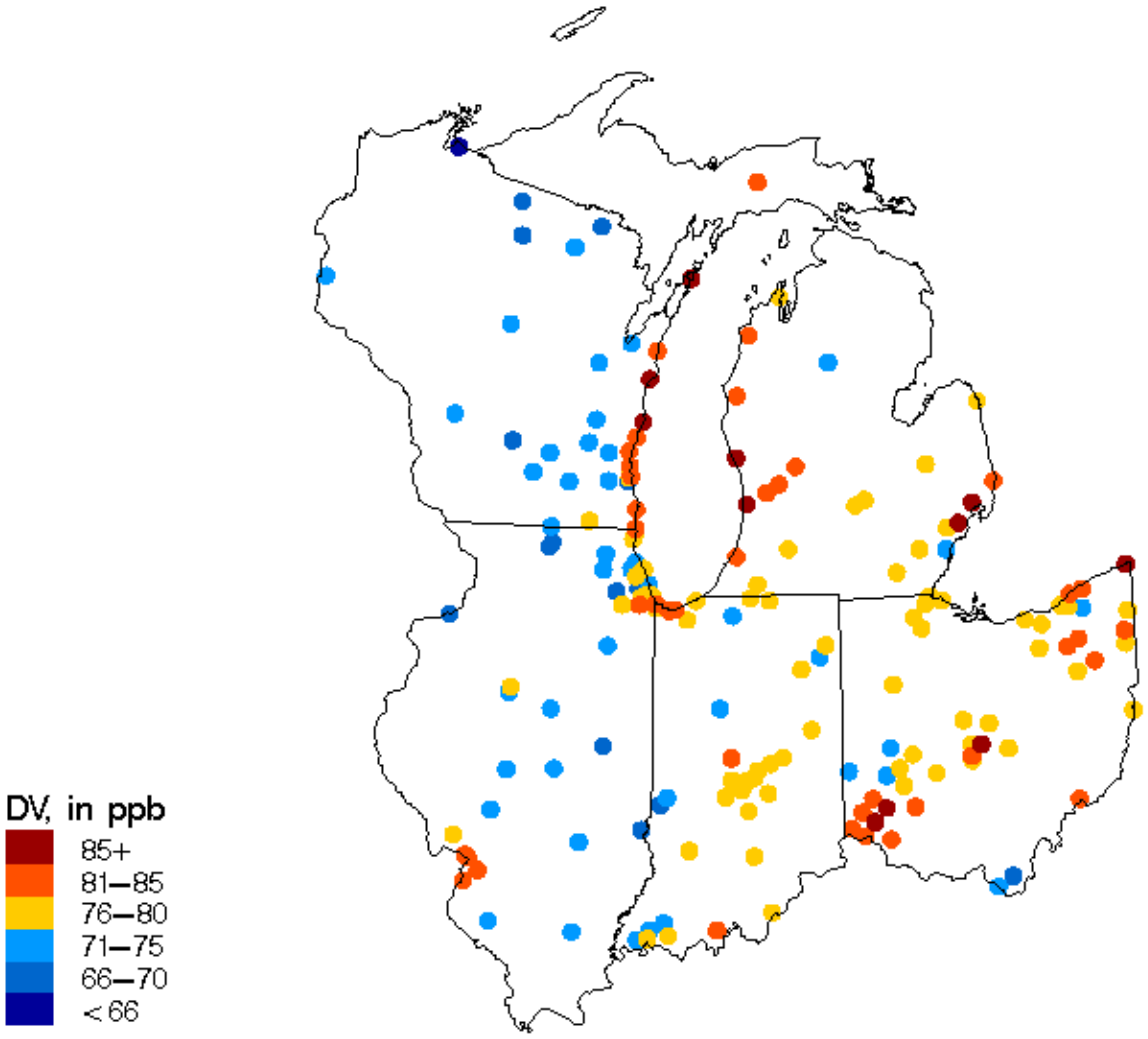


Figure 1. 8-hour ozone design values (2005-2007)

Table 1. Ozone Data for Select Sites in 5-State Region

Key Sites	4th High 8-hour Value								Design Values				
	'01	'02	'03	'04	'05	'06	'07		'01-'03	'02-'04	'03-'05	'04-'06	'05-'07
Lake Michigan Area													
Chiwaukee	99	116	88	78	93	79	85		**101**	**94**	**86**	83	**85**
Racine	92	111	82	69	95	71	77		**95**	**87**	82	78	81
Milwaukee-Bayside	93	99	92	73	93	73	83		**94**	**88**	**86**	79	83
Harrington Beach	102	93	99	72	94	72	84		**98**	**88**	**88**	79	83
Manitowoc	97	83	92	74	95	78	85		**90**	83	**87**	82	**86**
Sheboygan	102	105	93	78	97	83	88		**100**	**92**	**89**	**86**	**89**
Kewaunee	90	92	97	73	88	76	85		**93**	**87**	**86**	*79*	83
Door County	95	95	93	78	101	79	92		**94**	**88**	**90**	**86**	**90**
Hammond	90	101	81	67	87	75	77		**90**	83	78	76	79
Whiting				64	88	81	88					77	**85**
Michigan City	90	107	82	70	84	75	73		**93**	**86**	78	76	77
Ogden Dunes	85	101	77	69	90	70	84		**87**	82	78	76	81
Holland	92	105	96	79	94	91	94		**97**	**93**	**89**	**88**	**93**
Jenison	86	93	91	69	86	83	88		**90**	84	82	79	**85**
Muskegon	95	96	94	70	90	90	86		**95**	**86**	84	83	**88**
Indianapolis Area													
Noblesville	88	101	101	75	87	77	84		**96**	**92**	**87**	79	82
Fortville	89	101	92	72	80	75	81		**94**	**88**	81	75	78
Fort B. Harrison	87	100	91	73	80	76	83		**92**	**88**	81	76	79
Detroit Area													
New Haven	95	95	102	81	88	78	93		**97**	**92**	**90**	82	**86**
Warren	94	92	101	71	89	78	91		**95**	**88**	**87**	79	**86**
Port Huron	84	100	87	74	88	78	89		**90**	**87**	83	80	**85**
Cleveland Area													
Ashtabula (Conneaut)	97	103	99	81	93	86	92		**99**	**94**	**91**	**86**	**90**
Notre Dame (Geauga)	99	115	97	75	88	70	68		**103**	**95**	**86**	77	75
Eastlake (Lake)	89	104	92	79	97	83	74		**95**	**91**	**89**	**86**	84
Akron (Summit)	98	103	89	77	89	77	91		**96**	**89**	**85**	81	**85**
Cincinnati Area													
Wilmington (Clinton)	93	99	96	78	83	81	82		**96**	**91**	**85**	80	82
Sycamore (Hamilton)	88	100	93	76	89	81	90		**93**	**89**	**86**	82	**86**
Hamilton (Butler)	83	100	94	75	86	79	91		**92**	**89**	**85**	80	**85**
Middleton (Butler)	87	98	83	76	88	76	91		**89**	**85**	82	80	**85**
Lebanon (Warren)	85	98	95	81	92	86	88		**92**	**91**	**89**	**86**	**88**
Columbus Area													
London (Madison)	84	97	90	75	81	76	83		**90**	**87**	82	77	80
New Albany (Franklin)	90	103	94	78	92	82	87		**95**	**91**	**88**	84	**87**
Franklin (Franklin)	83	99	84	73	86	79	79		**88**	**85**	81	79	81
Ohio Other Areas													
Marietta (Washington)	85	95	80	77	88	81	86		**86**	84	81	82	**85**
St. Louis Area													
W. Alton (MO)	85	99	91	77	89	91	89		**91**	**89**	**85**	**85**	**89**
Orchard (MO)	88	98	90	76	92	92	83		**92**	**88**	**86**	**86**	**89**
Sunset Hills (MO)	88	98	88	70	89	80	89		**91**	**85**	82	79	**86**
Arnold (MO)	86	93	82	70	92	79	87		**87**	81	81	80	**86**
Margaretta (MO)	80	98	90	72	91	76	91		**89**	**86**	84	79	**86**
Maryland Heights (MO)					88	84	94						**88**

Meteorology and Transport: Most pollutants exhibit some dependence on meteorological factors, especially wind direction, because that governs which sources are upwind and thus most influential on a given sample. Ozone is even more dependent, since its production is driven by high temperatures and sunlight, as well as precursor concentrations (see, for example, Figure 2).

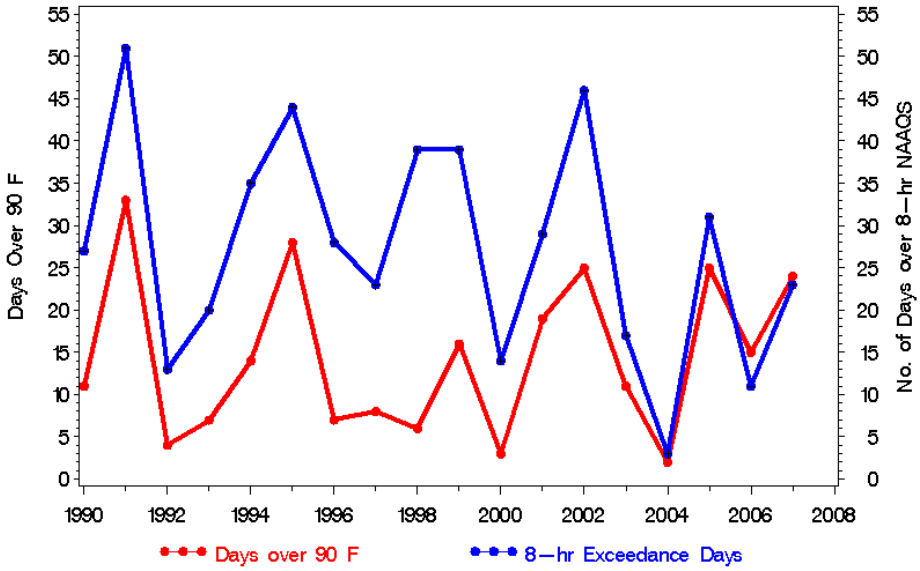


Figure 2. Number of hot days and 8-hour "exceedance" days in 5-state region

Qualitatively, ozone episodes in the region are associated with hot weather, clear skies (sometimes hazy), low wind speeds, high solar radiation, and southerly to southwesterly winds. These conditions are often a result of a slow-moving high pressure system to the east of the region. The relative importance of various meteorological factors is discussed later in this section.

Transport of ozone (and its precursors) is a significant factor and occurs on several spatial scales. Regionally, over a multi-day period, somewhat stagnant summertime conditions can lead to the build-up in ozone and ozone precursor concentrations over a large spatial area. This pollutant air mass can be advected long distances, resulting in elevated ozone levels in locations far downwind. An example of such an episode is shown in Figure 3.

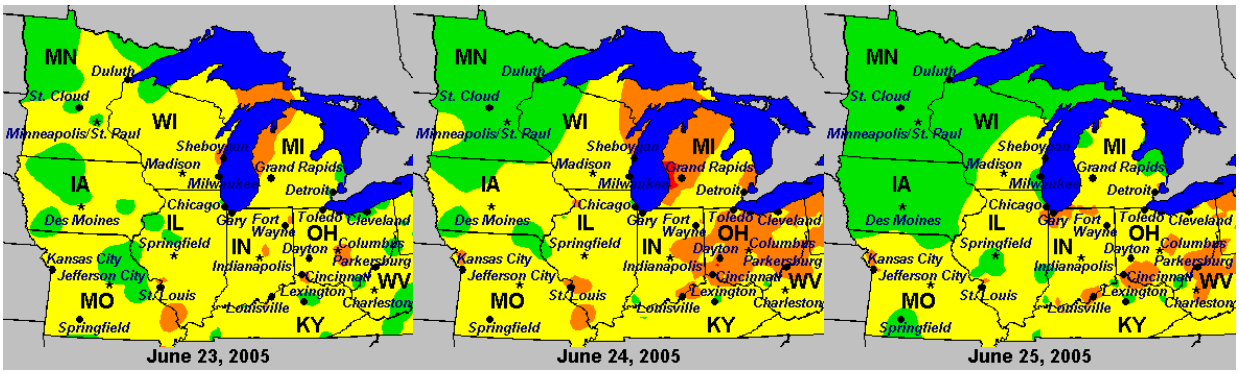


Figure 3. Example of elevated regional ozone concentrations (June 23 – 25, 2005)

Note: hotter colors represent higher concentrations, with orange representing concentrations above the 8-hour standard

Locally, emissions from urban areas add to the regional background leading to ozone concentration hot spots downwind. Depending on the synoptic wind patterns (and local land-lake breezes), different downwind areas are affected (see, for example, Figure 4).

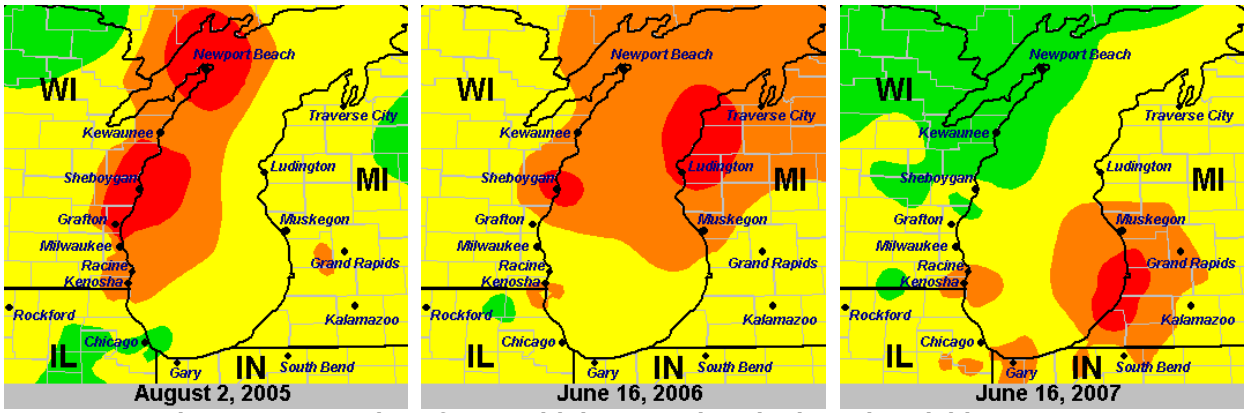


Figure 4. Examples of recent high ozone days in the Lake Michigan area

Note: hotter colors represent higher concentrations, with orange representing concentrations above the 8-hour standard

Aloft (aircraft) measurements in the Lake Michigan area also provide evidence of elevated regional background concentrations and "plumes" from urban areas. For one example summer day (August 20, 2003 – see Figure 5), the incoming background ozone levels were on the order of 80 – 100 ppb and the downwind ozone levels over Lake Michigan were on the order of 100 - 150 ppb (STI, 2004).

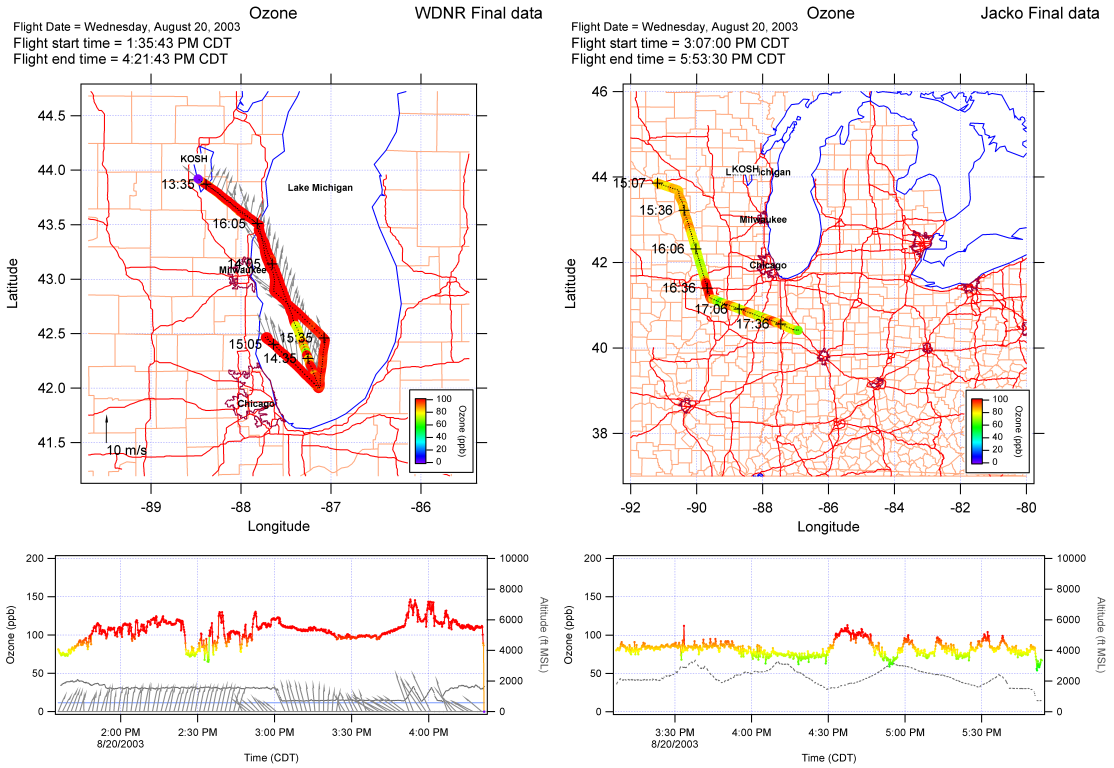


Figure 5. Aircraft ozone measurements over Lake Michigan (left) and along upwind boundary (right) – August 20, 2003 (Note: aircraft measurements reflect instantaneous values)

As discussed in Section 4, residual nonattainment is projected in at least one area in the 5-state region –i.e., western Michigan. To understand the source regions likely impacting high ozone concentrations in western Michigan and estimate the impact of these source regions, two simple transport-related analyses were performed.

First, back trajectories were constructed using the HYSPLIT model for high ozone days (8-hour peak > 80 ppb) during the period 2002-2006 in western Michigan to characterize general transport patterns. Composite trajectory plots for all high ozone days based on data from three sites (Cass County, Holland, and Muskegon) are provided in Figure 6. The plots point back to areas located to the south-southwest (especially, northeastern Illinois and northwestern Indiana) as being upwind on these high ozone days.

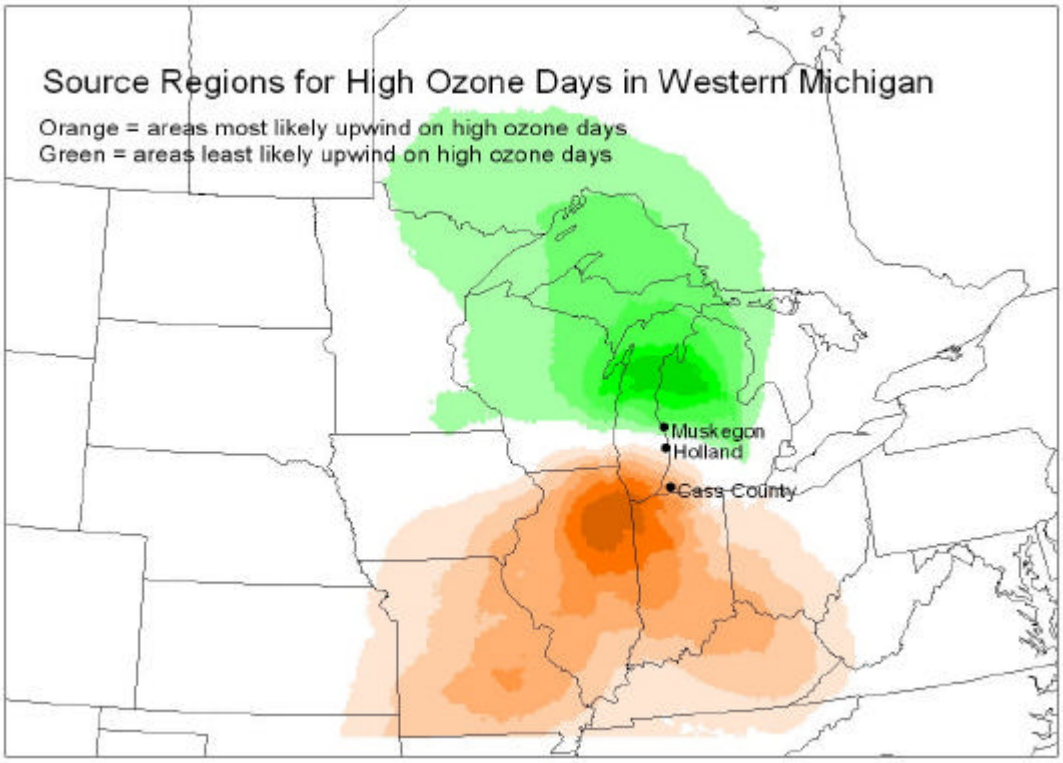


Figure 6 Back trajectory analysis showing upwind areas associated with high ozone concentrations

Second, to assess the impact from Chicago/NW Indiana, Blanchard (2005a) compared ozone concentrations upwind (Braidwood, IL), within Chicago (ten sites in the City), and downwind (Holland and Muskegon) for days in 1999 – 2002 with southwesterly winds - i.e., transport towards western Michigan. Figure 7 shows the distribution of daily peak 8-hour ozone concentrations by day-of-week, with a line connecting the mean values. The difference between day-of-week mean values at downwind and upwind sites indicates that Chicago/NW Indiana contributes about 10-15 ppb to downwind ozone levels.

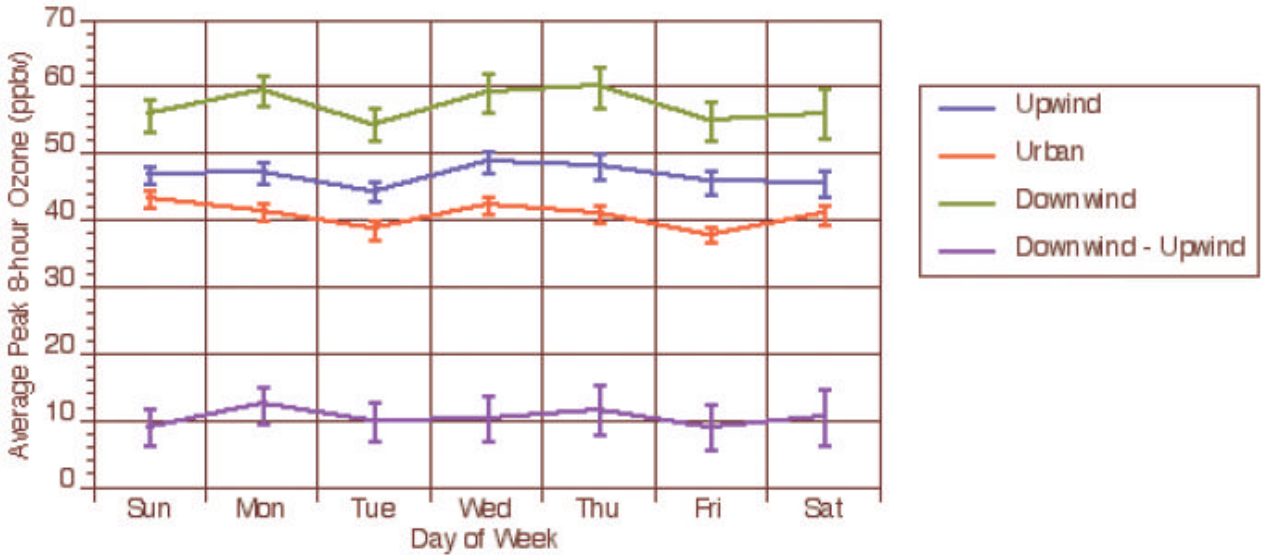


Figure 7. Mean day-of-week peak 8-hour ozone concentrations at sites upwind, within, and downwind of Chicago, 1999 – 2002 (southwesterly wind days)

Based on this information, the following key findings related to transport can be made:

- Ozone transport is a problem affecting many portions of the eastern U.S. The Lake Michigan area (and other areas in the LADCO region) both receive high levels of incoming (transported) ozone and ozone precursors from upwind source areas on many hot summer days, and contribute to the high levels of ozone and ozone precursors affecting downwind receptor areas.

- The presence of a large body of water (i.e., Lake Michigan) influences for the formation and transport of ozone in the Lake Michigan area. Depending on large-scale synoptic winds and local-scale lake breezes, different parts of the area experience high ozone concentrations. For example, under southerly flow, high ozone can occur in eastern Wisconsin, and under southwesterly flow, high ozone can occur in western Michigan.

- Downwind shoreline areas around Lake Michigan are affected by both regional transport of ozone and subregional transport from major cities in the Lake Michigan area. Counties along the western shore of Michigan (from Benton Harbor to Traverse City, and even as far north as the Upper Peninsula) are impacted by high levels of incoming (transported) ozone.

Data Variability: Since 1980, considerable progress has been made to meet the previous 1-hour ozone standard. Figure 8 shows the decline in both the 1-hour and 8-hour design values for the 5-state LADCO region over the last 25 years.

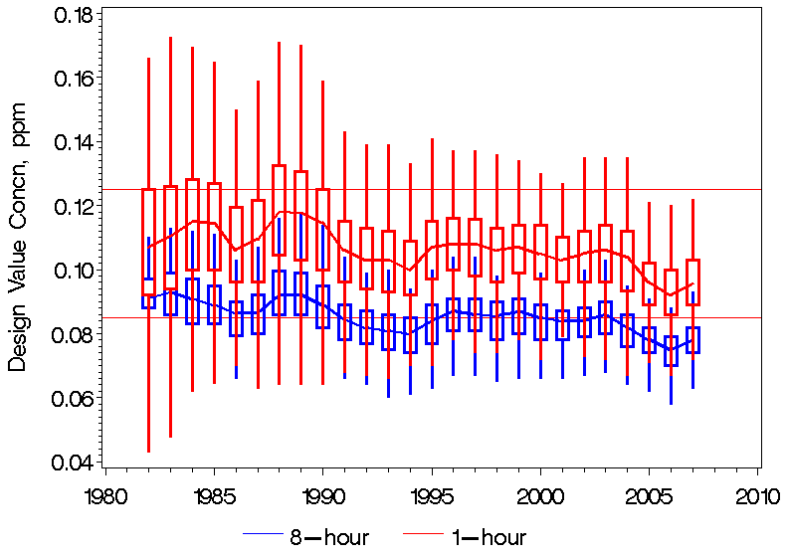


Figure 8 Ozone design value trends in 5-State region

The trend is more dramatic for the higher ozone sites in the 5-state region (see Figure 9). This plot shows a pronounced downward trend in the design value since the 2001-2003 period, due, in part, to the very low 4th high values in 2004.

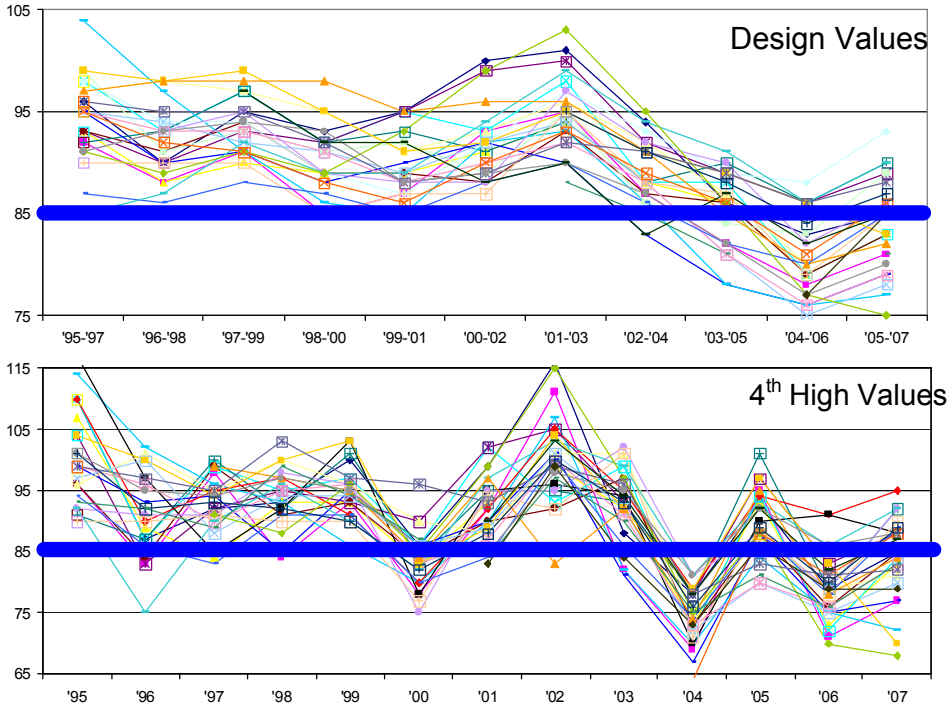


Figure 9. Trend in ozone design values and 4th high values for higher ozone sites in region

The improvement in ozone concentrations is also seen in the decrease in the number of sites measuring nonattainment over the past 15 years in the Lake Michigan area (see Figure 10).

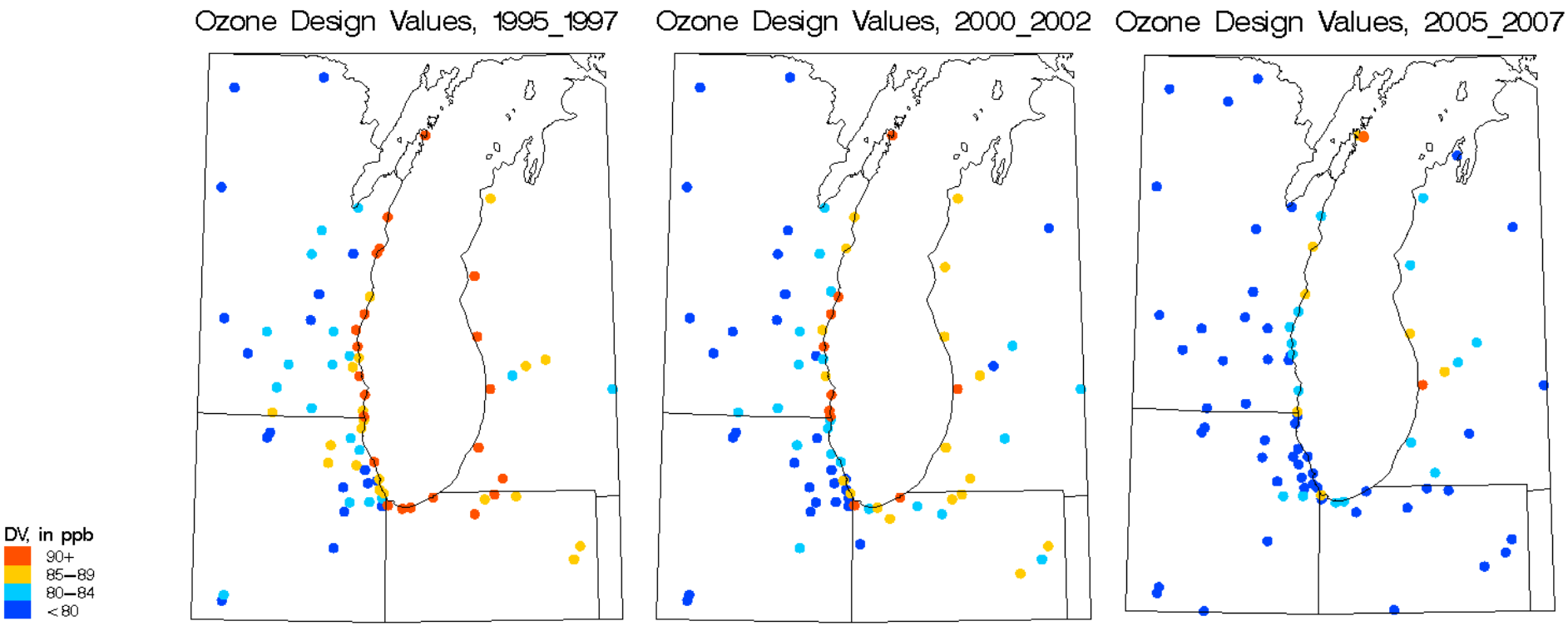


Figure 10. Ozone design value maps for 1995-1997, 2000-2002, and 2005-2007

Given the effect of meteorology on ambient ozone levels, year-to-year variations in meteorology can make it difficult to assess trends in ozone air quality. Two approaches were considered to adjust ozone trends for meteorological influences: an air quality-meteorology statistical model developed by EPA (i.e., Cox method), and statistical grouping of meteorological variables performed by LADCO (i.e., Classification and Regression Trees, or CART).

Cox Method: This method uses a statistical model to 'remove' the annual effect of meteorology on ozone (Cox and Chu, 1993). A regression model was fit to the 1997-2007 data to relate daily peak 8-hour ozone concentrations to six daily meteorological variables plus seasonal and annual factors (Kenski, 2008a). Meteorological variables included were daily maximum temperature, mid-day average relative humidity, morning and afternoon wind speed and wind direction. The model is then used to predict 4th high ozone values. By holding the meteorological effects constant, the long term trend can be examined independently of meteorology. Presumably, any trend reflects changes in emissions of ozone precursors.

Figure 11a shows the meteorologically-adjusted 4th high ozone concentrations for several monitors near major urban areas in the region. The plots indicate a general downward trend since the late 1990s for most cities, indicating that recent emission reductions have had a positive effect in improving ozone air quality.

A similar model was run to examine meteorologically adjusted trends in seasonal average ozone. This model incorporates more meteorological variables, including rain and long-distance transport (direction and distance). Model development was documented in Camalier et al., 2007. The seasonal average trends are shown in Figure 11b. Trends determined by seasonal model for the same set of sites examined above are consistent with those developed by the 4th high model.

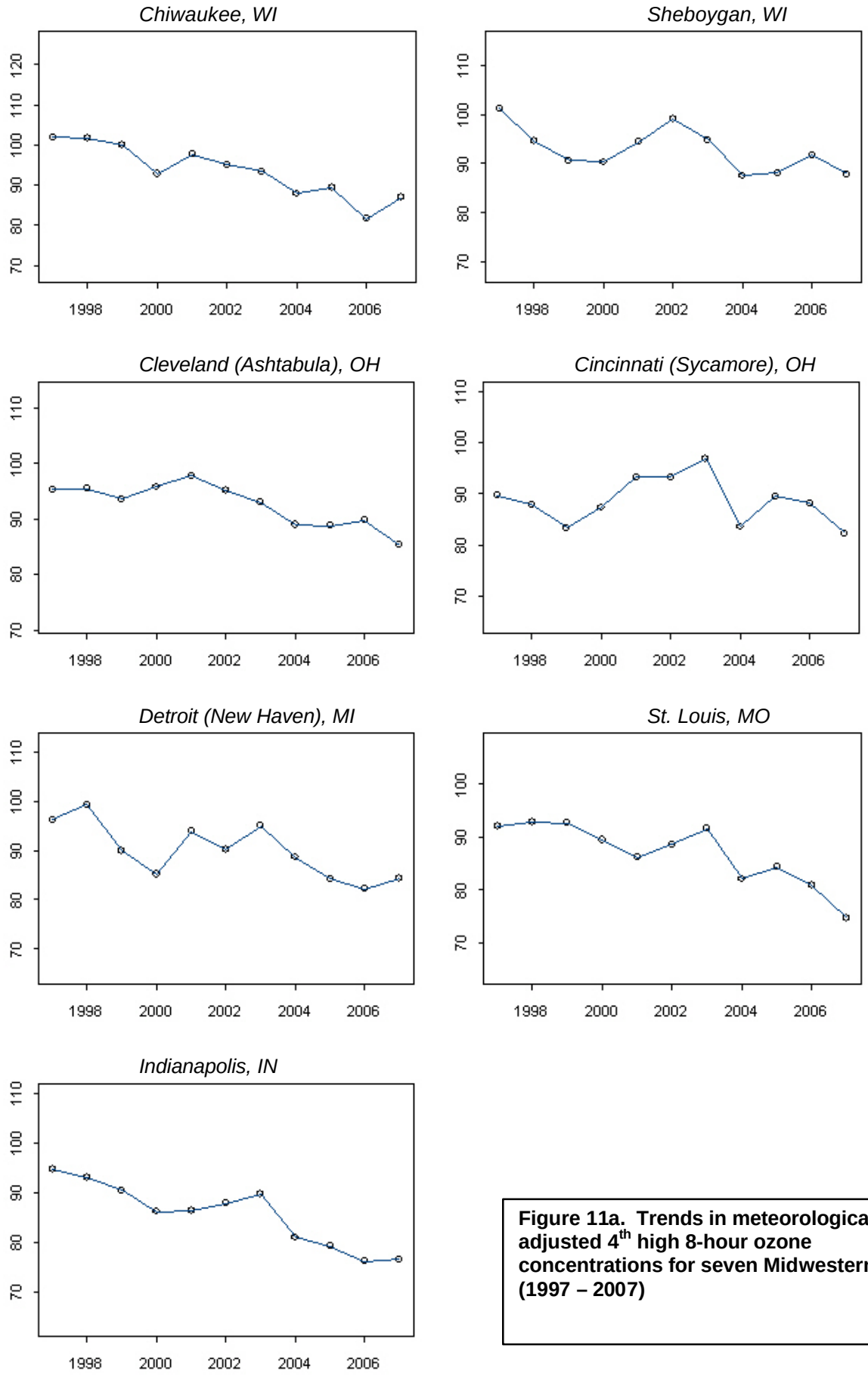


Figure 11a. Trends in meteorologically adjusted 4th high 8-hour ozone concentrations for seven Midwestern sites (1997 – 2007)

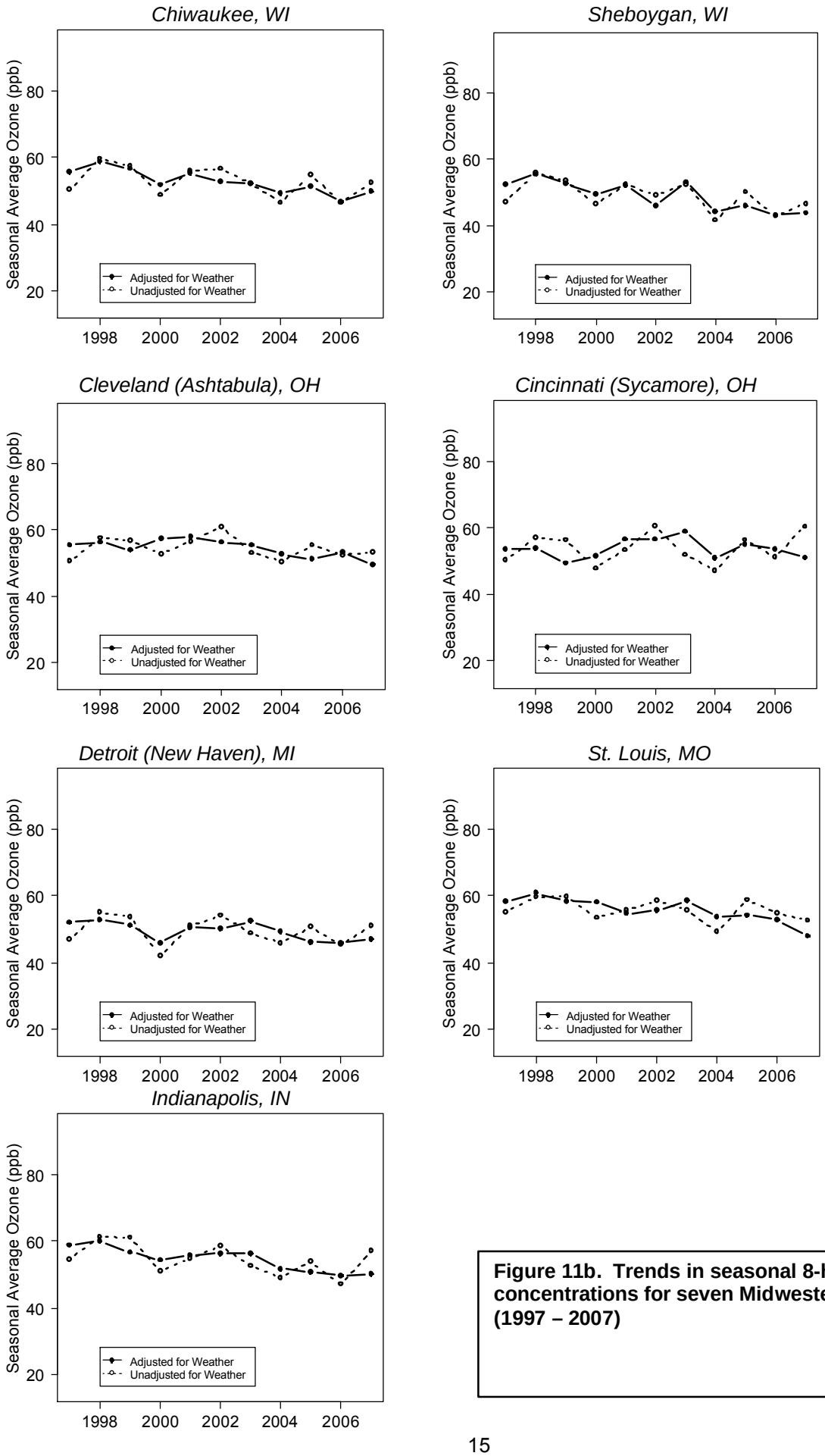


Figure 11b. Trends in seasonal 8-hour ozone concentrations for seven Midwestern sites (1997 – 2007)

CART: Classification and Regression Tree (CART) analysis is another statistical technique which partitions data sets into similar groups (Breiman et al., 1984). CART analysis was performed using data for the period 1995-2007 for 22 selected ozone monitors with current 8-hour design values close to or above the standard (Kenski, 2008b). The CART model searches through 60 meteorological variables to determine which are most efficient in predicting ozone. Although the exact selection of predictive variables changes from site to site, the most common predictors were temperature, wind direction, and relative humidity. Only occasionally were upper air variables, transport time or distance, lake breeze, or other variables significant. (Note, the ozone and meteorological data for the CART analysis are the same as used in the EPA/Cox analysis.)

For each monitor, regression trees were developed that classify each summer day (May-September) by its meteorological conditions. Similar days are assigned to nodes, which are equivalent to branches of the regression tree. Ozone time series for the higher concentration nodes are plotted for select sites in Figure 12. By grouping days with similar meteorology, the influence of meteorological variability on the trend in ozone concentrations is partially removed; the remaining trend is presumed to be due to trends in precursor emissions or other non-meteorological influences. Trends over the 13-year period at most sites were found to be declining, with the exception of Detroit which showed fairly flat trends. Comparison of the average of the high concentration node values for 2001-2003 v. 2005-2007 showed an improvement of about 5 ppb across all sites (even Detroit).

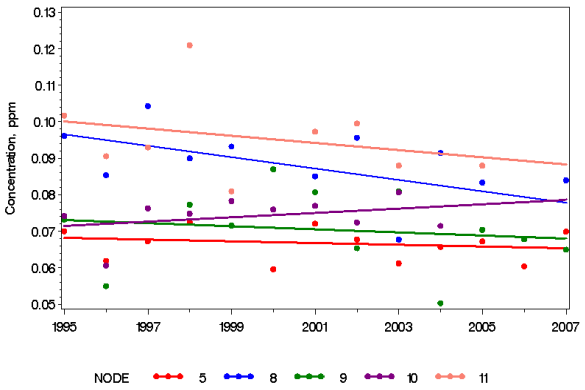
The effect of meteorology was further examined by using an ozone conduciveness index (Kenski, 2008b). This metric reflects the variability from the 13-year average in the number of days in the higher ozone concentration nodes (see Figure 13). Examination of these plots indicates:

- 2002 and 2005 were both above normal, with 2002 tending to be more severe; and
- 2001-2003 and 2005-2007 were both above normal, with no clear pattern in which period was more severe (i.e., ozone conduciveness values were similar at most sites, 2001-2003 values were higher at a few sites, and 2005-2007 values were higher at a few sites).

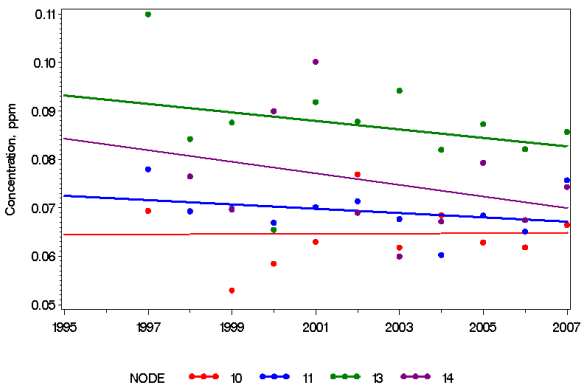
Given the similarity in ozone conduciveness between 2001-2003 and 2005-2007, the improvement in ozone levels noted above is presumed to be due to non-meteorological factors (i.e., emission reductions).

In conclusion, all three statistical approaches (CART and the two nonlinear regression models) show a similar result; ozone in the urban areas of the LADCO region has declined during the 1997-2007 period, even when meteorological variability is accounted for. The decreases are present whether seasonal average ozone, peak values (annual 4th highs), or a subset of high days with similar meteorology are considered. The consistency in results across models is a good indication that these trends reflect impacts of emission control programs.

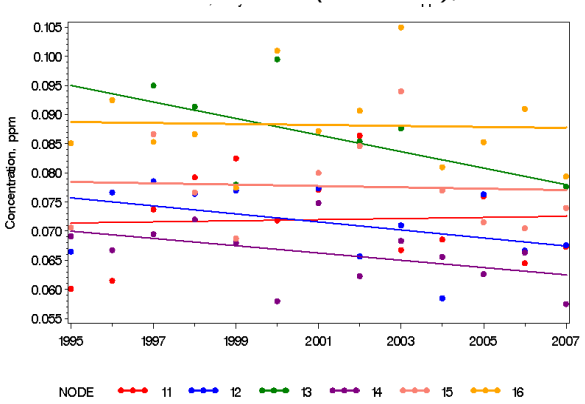
Chiwaukee, WI



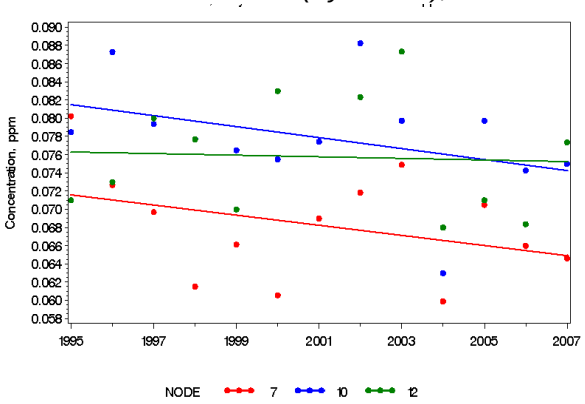
Sheboygan, WI



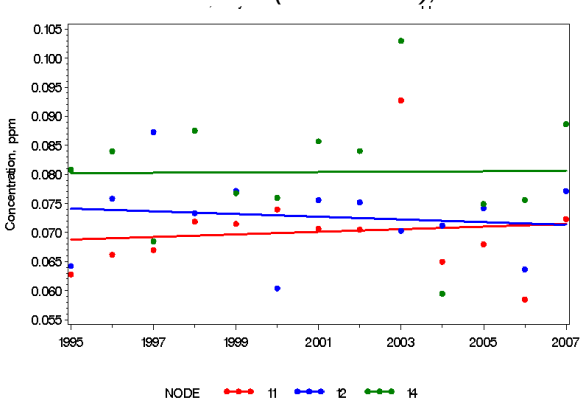
Cleveland (Ashtabula), OH



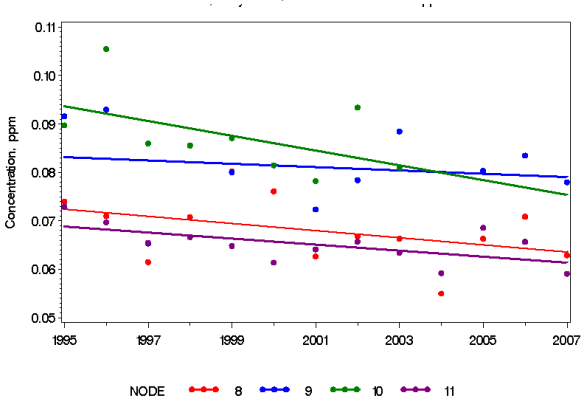
Cincinnati (Sycamore), OH



Detroit (New Haven), MI



St. Louis, MO



Indianapolis, IN

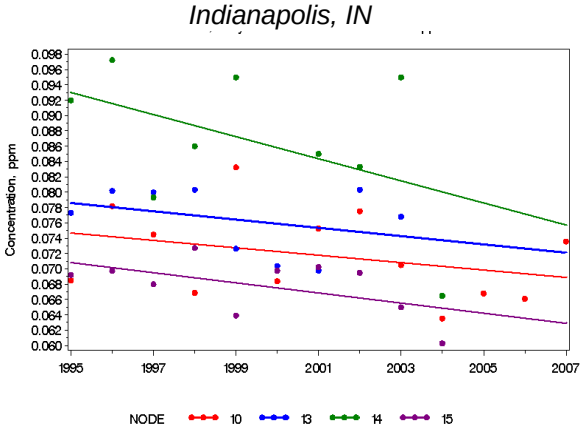


Figure 12. Trends for higher ozone CART groups (average ozone > 65 ppb) for seven Midwestern sites (1995 – 2007)

Note: line represents linear best fit

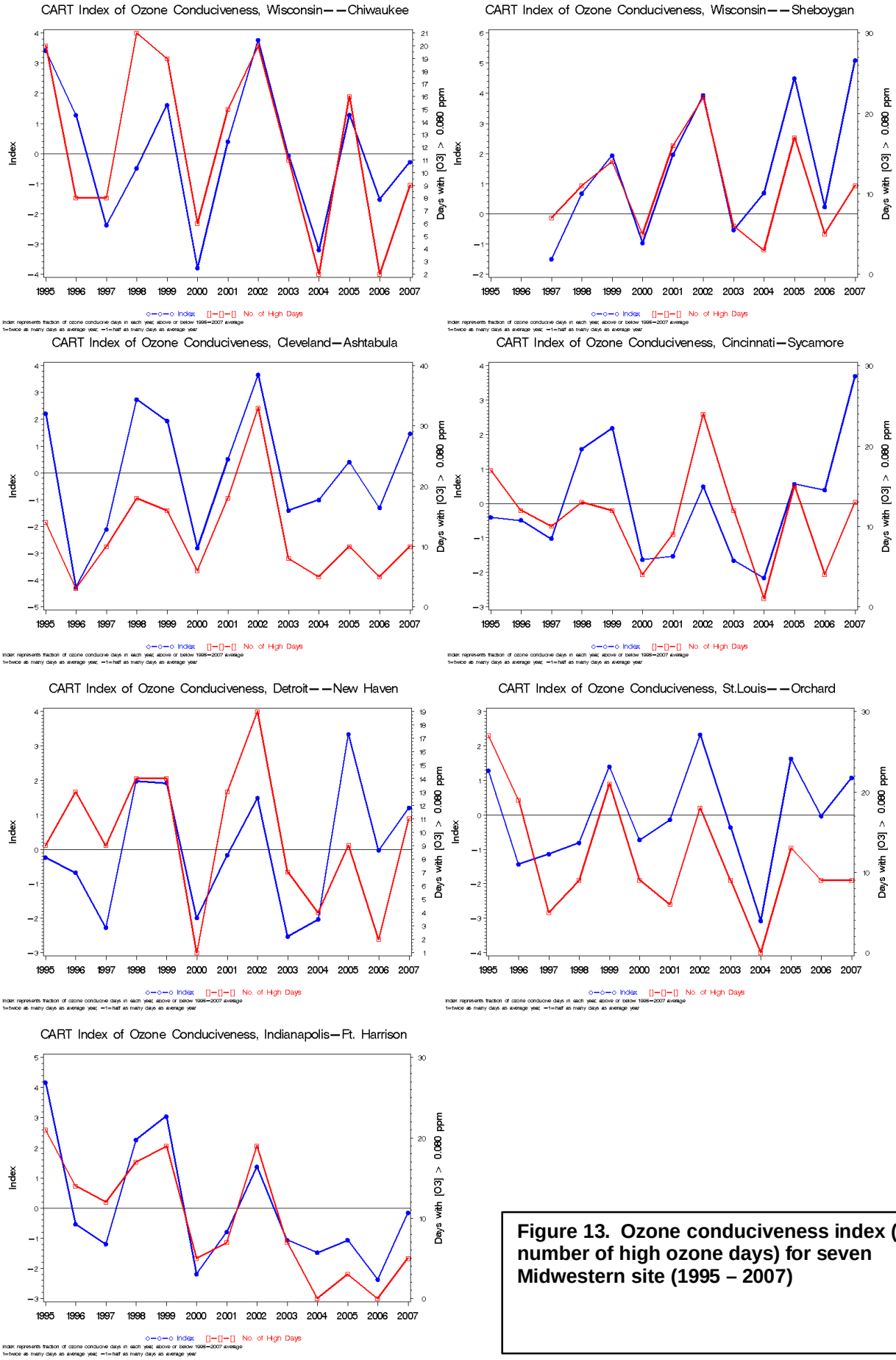


Figure 13. Ozone conduciveness index (and number of high ozone days) for seven Midwestern site (1995 – 2007)

Precursor Sensitivity: Ozone is formed from the reactions of hydrocarbons and nitrogen oxides under meteorological conditions that are conducive to such reactions (i.e., warm temperatures and strong sunlight). In areas with high VOC/NOx ratios, typical of rural environments (with low NOx), ozone tends to be more responsive to reductions in NOx. Conversely, in areas with low VOC/NOx ratios, typical of urban environments (with high NOx), ozone tends to be more responsive to VOC reductions.

An analysis of VOC and NO_x-limitation was conducted with the ozone MAPPER program, which is based on the Smog Production (SP) algorithm (Blanchard, et al., 2003). The "Extent of Reaction" parameter in the SP algorithm provides an indication of VOC and NOx sensitivity:

Extent Range	**Precursor Sensitivity**
< 0.6	VOC-sensitive
0.6 – 0.8	Transitional
> 0.8	NOx-sensitive

A map of the Extent of Reaction values for high ozone days is provided in Figure 14. As can be seen, ozone is usually VOC-limited in cities and NOx-limited in rural areas. (Data from aircraft measurements suggest that ozone is usually NO_x-limited over Lake Michigan and away from urban centers on days when ozone in the urban centers is VOC-limited.) The highest ozone days were found to be NO_x-limited. This analysis suggests that a NOx reduction strategy would be effective in reducing ozone levels. Examination of day-of-week concentrations, however, raises some question about the effectiveness of NOx reductions.

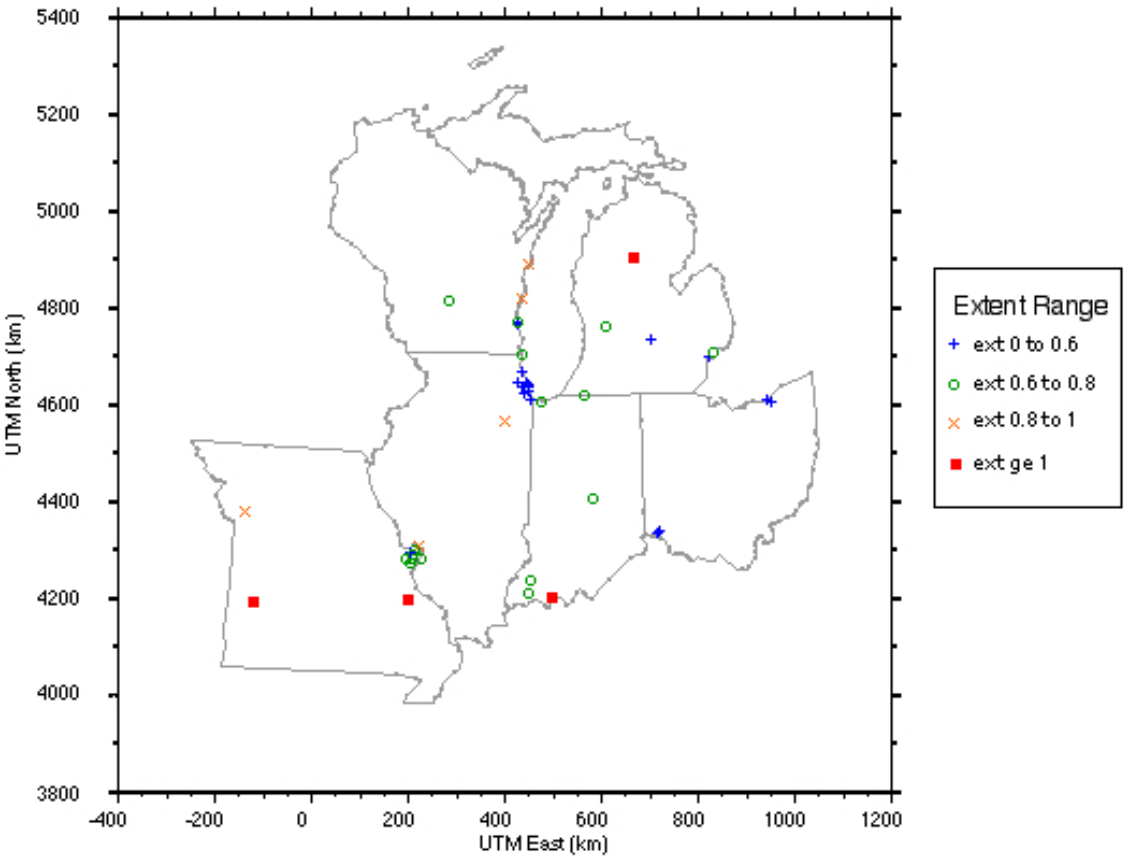


Figure 14. Mean afternoon extent of reaction (1998 – 2002)

Blanchard (2004 and 2005a) examined weekend-weekday differences in ozone and NO_x in the Midwest. All urban areas in these two studies exhibited substantially lower (40-60%) weekend concentrations of NO_x compared to weekday concentrations. Despite lower weekend NO_x concentrations, weekend ozone concentrations were not lower; in fact, most urban sites had higher concentrations of ozone, although the increase was generally not statistically significant (see Figure 15). This small but counterproductive change in **local** ozone concentrations suggests that **local** urban-scale NO_x reductions alone may not be very effective.

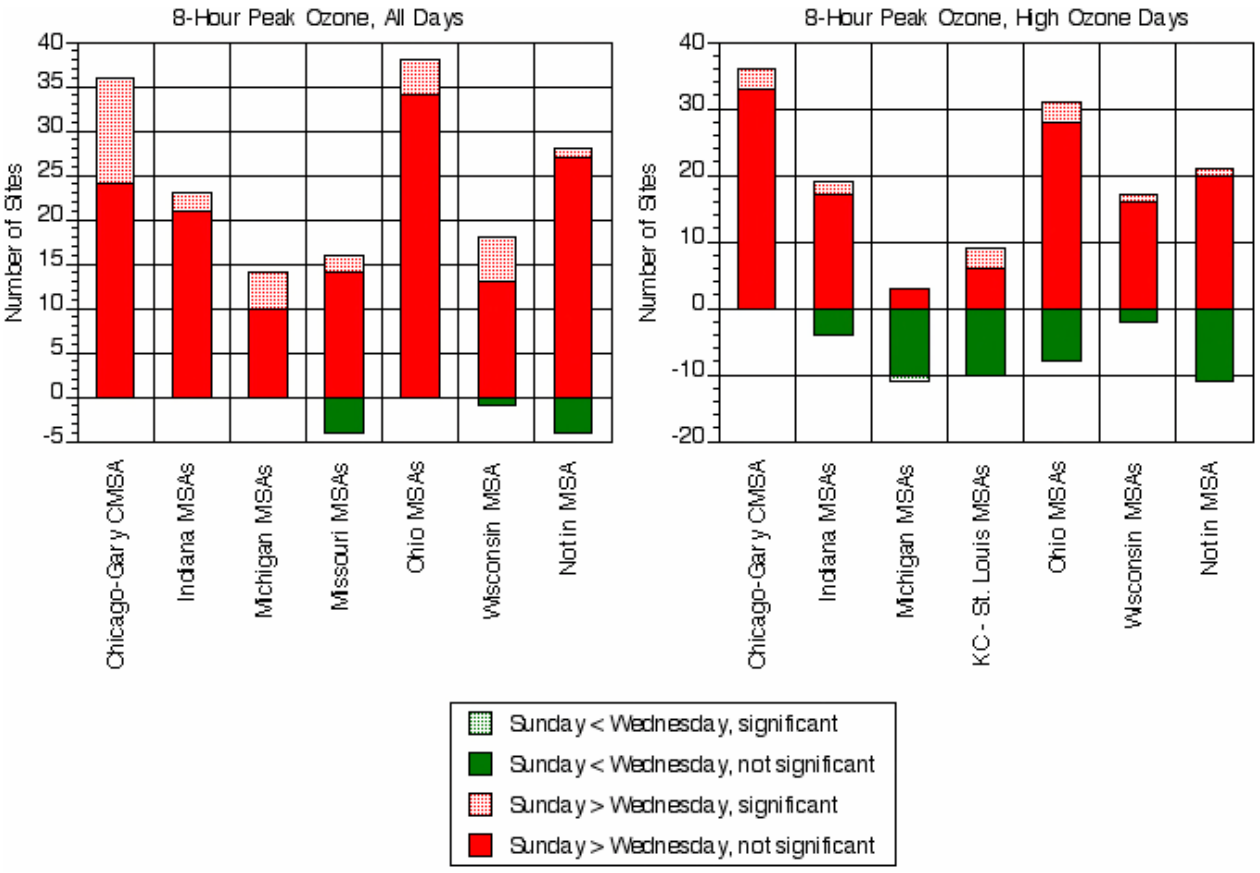


Figure 15. Weekday/weekend differences in 8-hour ozone – number of sites with weekend increase (positive values) v. number of sites with weekend decreases (negative values)

Two additional analyses, however, demonstrate the positive effect of NOx emission reductions on downwind ozone concentrations. First, Blanchard (2005a) looked at the effect of changes in precursor emissions in Chicago on downwind ozone levels in western Michigan. For the transport days of interest (i.e., southwesterly flow during the summers of 1999 – 2002), mean NOx concentrations in Chicago are about 50% lower and mean ozone concentrations at the (downwind) western Michigan sites are about 1.5 – 5.2 ppb (3 – 8 %) lower on Sunday compared to Wednesday. This degree of change in downwind ozone levels suggests a positive, albeit non-linear response to urban area emission reductions.

Second, Environ (2007a) examined the effect of differences in day-of-week emissions in southeastern Michigan on downwind ozone levels. This modeling study found that weekend changes in ozone precursor emissions cause both increases and decreases in Southeast Michigan ozone, depending upon location and time:

- Weekend increases in 8-hour maximum ozone occur in and immediately downwind of the Detroit urban area (i.e., in VOC-sensitive areas).
- Weekend decreases in 8-hour maximum ozone occur outside and downwind of the Detroit urban area (i.e., in NOx-sensitive areas).
- At the location of the peak 8-hour ozone downwind of Detroit, ozone was lower on weekends than weekdays.
- Ozone benefits (reductions) due to weekend emission changes in Southeast Michigan can be transported downwind for hundreds of miles.
- Southeast Michigan benefits from lower ozone transported into the region on Saturday through Monday because of weekend emission changes in upwind areas.

In summary, these analyses suggest that urban VOC reductions and regional (urban and rural) NOx reductions will be effective in lowering ozone concentrations. Local NOx reductions can lead to local ozone increases (i.e., NOx disbenefits), but this effect does not appear to pose a problem with respect to attainment of the standard. It should also be noted that urban VOC and regional NOx reductions are likely to have multi-pollutant benefits (e.g., both lower ozone and $PM_{2.5}$ impacts).

2.2 $PM_{2.5}$

In 1997, EPA adopted the $PM_{2.5}$ standards of 15 ug/m^3 (annual average) and 65 ug/m3 (24-hour average). The annual standard is attained if the 3-year average of the annual average $PM_{2.5}$ concentration is less than or equal to the level of the standard. The daily standard is attained if the 98th percentile of 24-hour $PM_{2.5}$ concentrations in a year, averaged over three years, is less than or equal to the level of the standard.

In 2006, EPA revised the $PM_{2.5}$ standards to 15 ug/m^3 (annual average) and 35 ug/m^3 (24-hour average).

Current Conditions: Maps of annual and 24-hour $PM_{2.5}$ design values for the 3-year period 2005-2007 are shown in Figure 16. The "hotter" colors represent higher concentrations, where red dots represent sites with design values above the annual standard. Currently, there are 30 sites in violation of the annual $PM_{2.5}$ standard.

Table 2 provides the annual $PM_{2.5}$ concentrations and associated design values since 2003 for several high monitoring sites throughout the region.

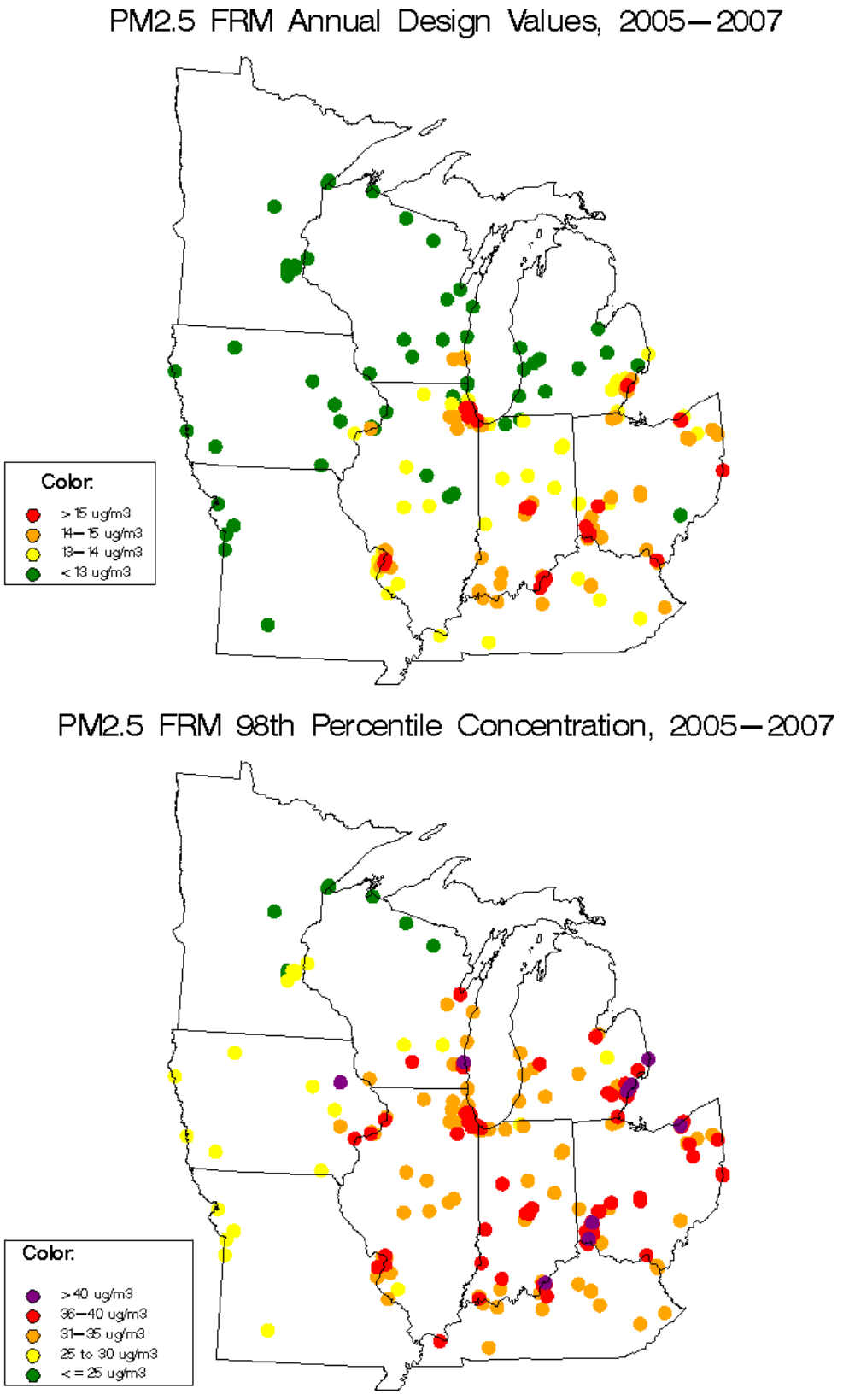


Figure 16. $PM_{2.5}$ design values - annual average (top) and 24-hour average (bottom) (2005-2007)

Table 2. PM2.5 Data for Select Sites in 5-State Region

			Annual Average Conc.					Design Values			2005 BY	2002 BY
Key Site	**County**	**Site ID**	**'03**	**'04**	**'05**	**'06**	**'07**	**'03 - '05**	**'04 - '06**	**'05 - '07**	**Average w/ 2007**	**Average**
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	**15.0**	**15.6**
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**	
Indy - Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**
Indy - W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**	
Indy - Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.0	15.3	17.0	16.2	16.2	**16.5**	**16.7**
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.4	13.6	14.7	15.4	14.9	14.9	**15.1**	**16.0**
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	15.9	**16.2**	**16.3**
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.4	**15.2**	**15.7**
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**

When EPA initially set the 24-hour standard at 65 µg/m^3, it also adopted the following concentration ranges for its Air Quality Index (AQI) scale:

Good	< 15 ug/m^3
Moderate	15-40 µg/m^3
Unhealthy for Sensitive Groups (USG)	40-65 µg/m^3
Unhealthy	65-150 µg/m^3

Figure 17 shows the frequency of these AQI categories for major metropolitan areas in the region. Daily average concentrations are often in the moderate range and occasionally in the USG range. Moderate and USG levels can occur any time of the year.

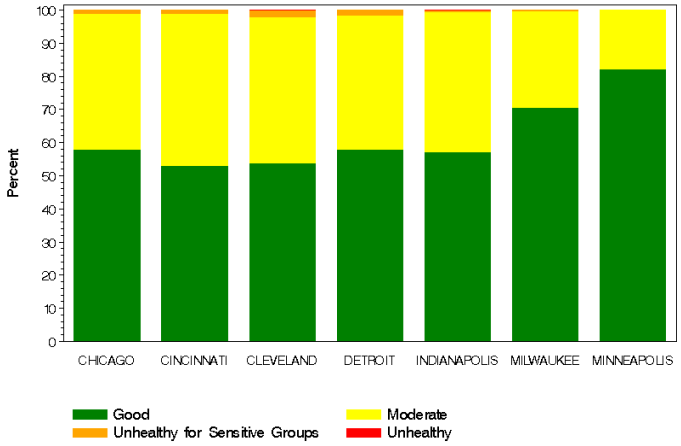


Figure 17. Percent of days in AQI categories for $PM_{2.5}$ (2002-2004)

Data Variability: $PM_{2.5}$ concentrations vary spatially, temporally, and chemically in the region. This variability is discussed further below.

On an annual basis, $PM_{2.5}$ exhibits a distinct and consistent spatial pattern. As seen in Figure 16, across the Midwest, annual concentrations follow a gradient from low values (5-6 µg/m^3) in northern and western areas (Minnesota and northern Wisconsin) to high values (17-18 µg/m^3) in Ohio and along the Ohio River. In addition, concentrations in urban areas are higher than in upwind rural areas, indicating that local urban sources add a significant increment of 2-3 µg/m^3 to the regional background of 12 - 14 µg/m^3 (see Figure 18).

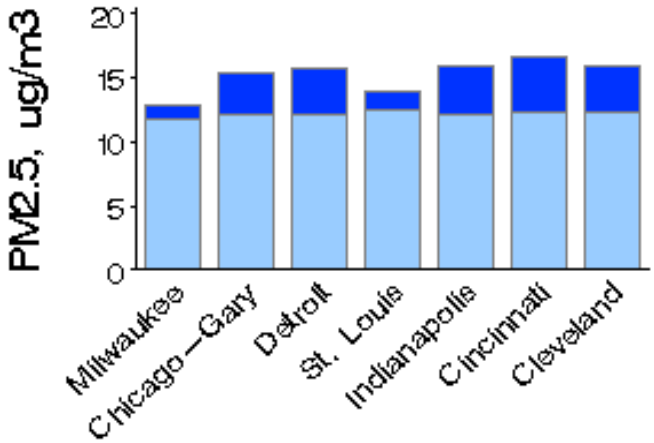


Figure 18. Regional (lighter shading) v. local components (darker shading) of annual average $PM_{2.5}$ concentrations

Because monitoring for $PM_{2.5}$ only began in earnest in 1999, after promulgation of the $PM_{2.5}$ standard, limited data are available to assess trends. Time series based on federal reference method (FRM) $PM_{2.5}$-mass data show a downward trend in each state (see Figure 19)[7].

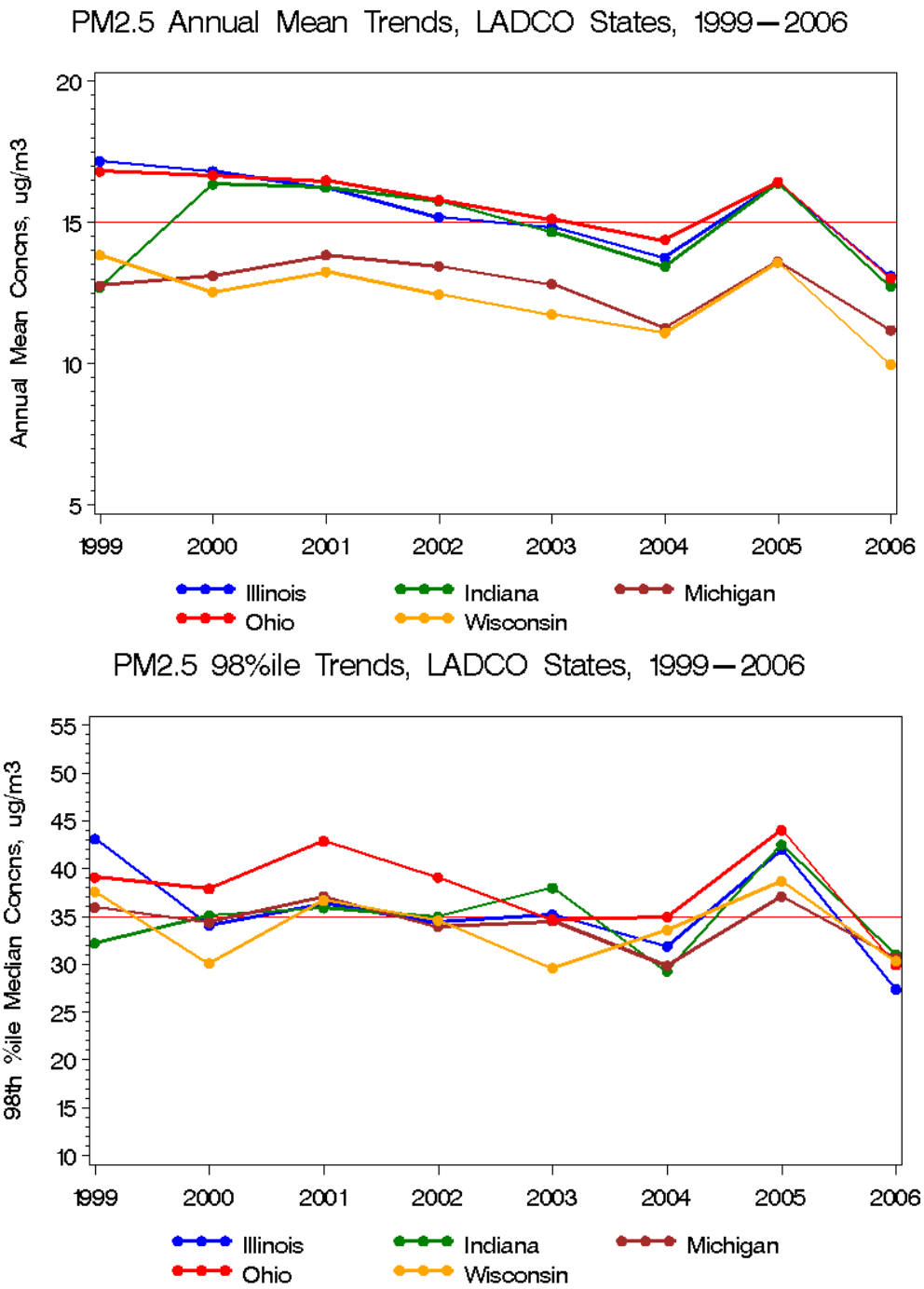


Figure 19. $PM_{2.5}$ trends in annual average (top) and daily concentrations (bottom)

[7] Despite the general downward trend since 1999, all states experienced an increase during 2005. Further analyses are underway to understand this increase (e.g., examination of meteorological and emissions effects).

A statistical analysis of $PM_{2.5}$ trends was performed using the nonparametric Theil test for slope (Hollander and Wolfe, 1973). Trends were generally consistent around the region, for both PM mass and for the individual components of mass. Figure 20 shows trends for $PM_{2.5}$ based on FRM data at sites with six or more years of data since 1999. The size and direction of each arrow shows the size and direction of the trend for each site; solid arrows show statistically significant trends and open arrows show trends that are not significant. Region-wide decreases are widespread and consistent; all sites had decreasing concentration trends (13 of the 38 were statistically significant). The average decrease for this set of sites is -0.24 ug/m^3/year.

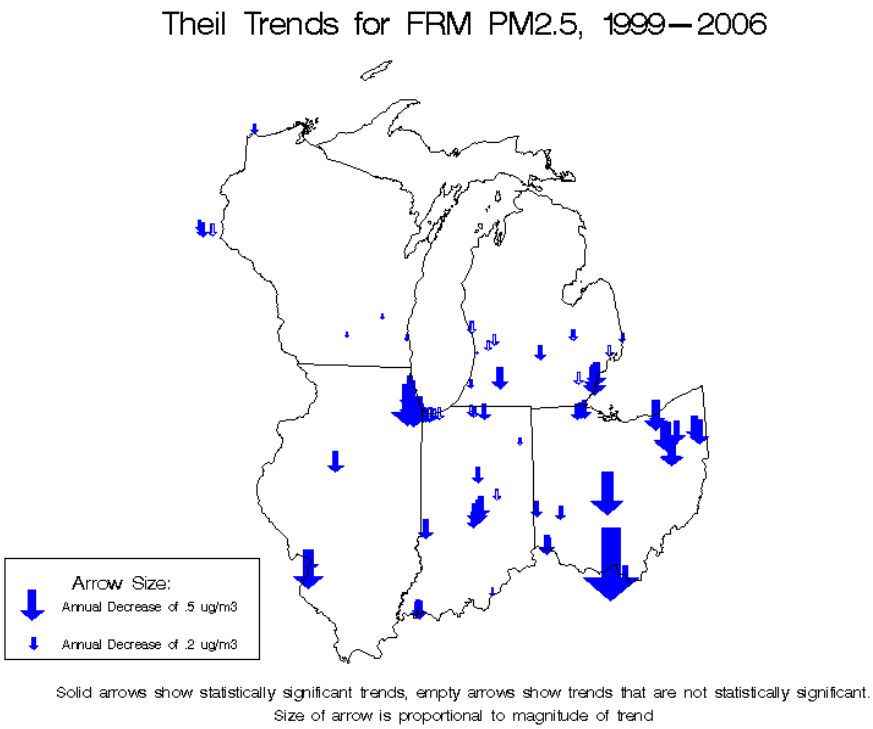


Figure 20. Annual trends in $PM_{2.5}$ mass (1999 – 2006)

Seasonal trends show mostly similar patterns (Figure 21). Trends were downward at most sites and seasons, with overall seasonal averages varying between -0.15 to -0.56 ug/m^3/year. The strongest and most significant decreases took place during the winter quarter (January - March). No statistically significant increasing trends were observed.

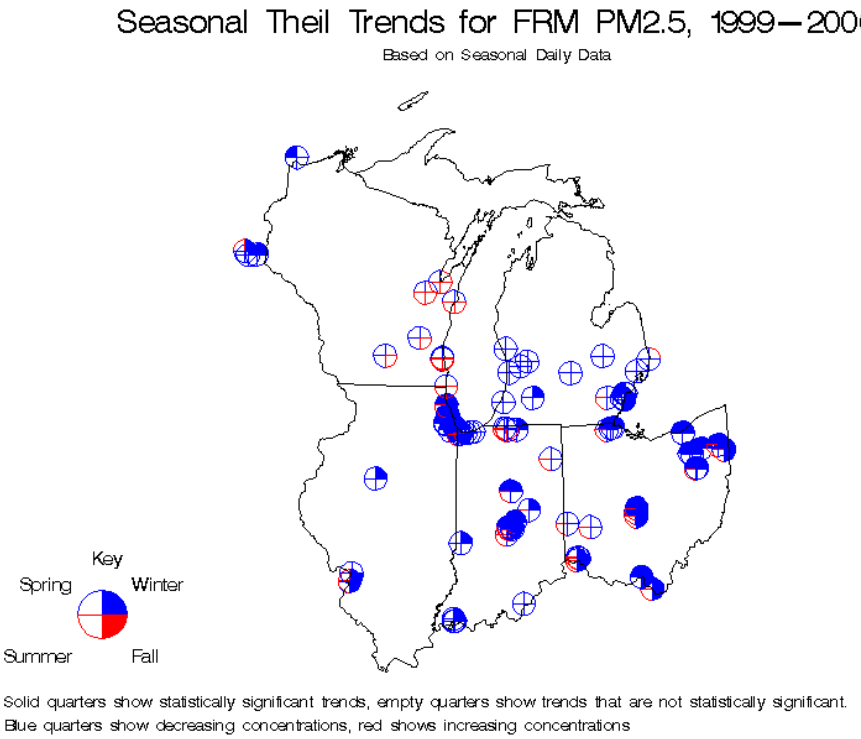


Figure 21. Seasonal trends in $PM_{2.5}$ mass (1999 – 2006)

$PM_{2.5}$ shows a slight variation from weekday to weekend, as seen in Figure 22. Although most cities have slightly lower concentrations on the weekend, the difference is usually less than 1 $\mu g/m^3$. There is a more pronounced weekday/weekend difference at monitoring sites that are strongly source-influenced. Rural monitors tend to show less of a weekday/weekend pattern than urban monitors.

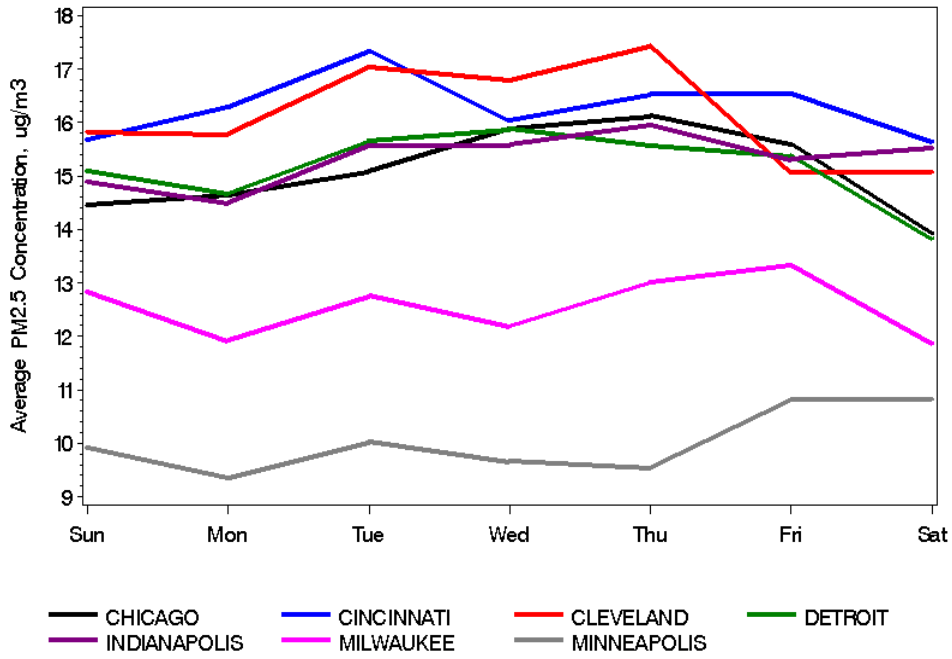


Figure 22 Day-of-week variability in $PM_{2.5}$ (2002-2004)

In the Midwest, $PM_{2.5}$ is made up of mostly ammonium sulfate, ammonium nitrate, and organic carbon in approximately equal proportions on an annual average basis. Elemental carbon and crustal matter (also referred to as soil) contribute less than 5% each.

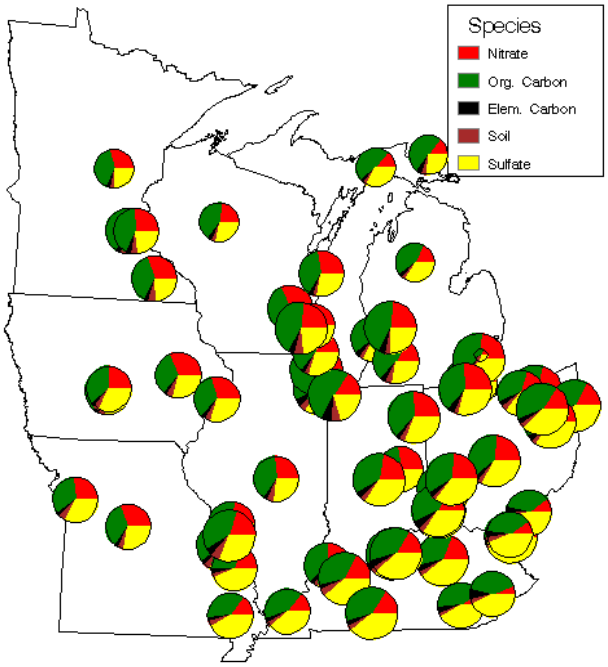


Figure 23. Spatial map of $PM_{2.5}$ chemical composition in the Midwest (2002-2003)

The three major components vary spatially (Figure 23), including notable urban and rural differences (Figure 24). The components also vary seasonally (Figure 25). These patterns account for much of the annual variability in $PM_{2.5}$ mass noted above.

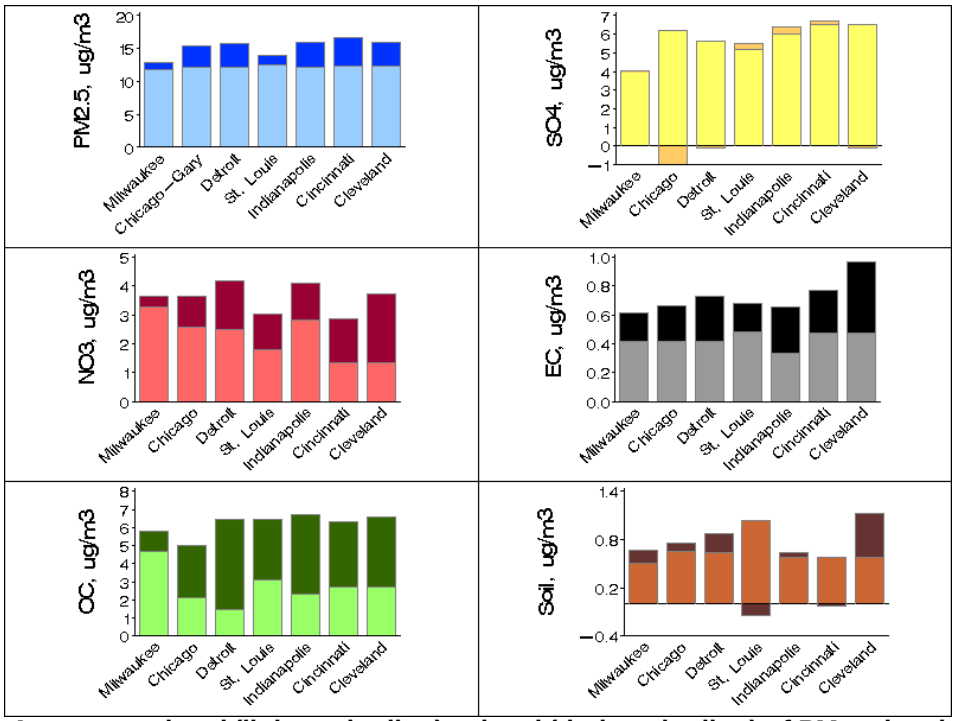


Figure 24. Average regional (lighter shading) v. local (darker shading) of $PM_{2.5}$ chemical species

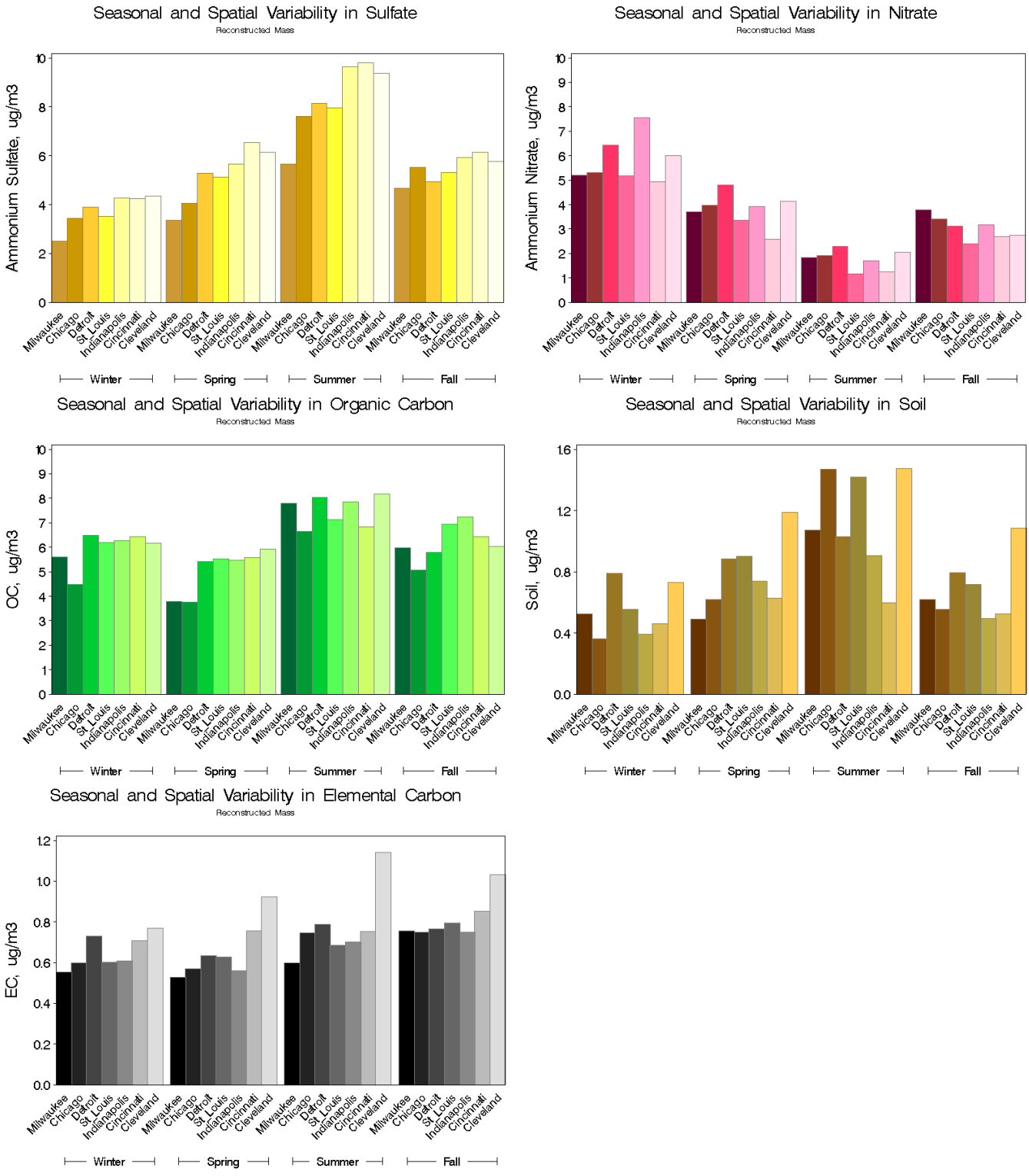


Figure 25 Seasonal and spatial variability in $PM_{2.5}$ components

Ammonium sulfate peaks in the summer and is highest in the southern and eastern parts of the Midwest, closest to the Ohio River Valley. Sulfate is primarily a regional pollutant; concentrations are similar in rural and urban areas and highly correlated over large distances. It is formed when sulfuric acid (an oxidation product of sulfur dioxide) and ammonia react in the atmosphere, especially in cloud droplets. Coal combustion is the primary source of sulfur dioxide; ammonia is emitted primarily from animal husbandry operations and fertilizer use.

Ammonium nitrate has almost the opposite spatial and seasonal pattern, with the highest concentrations occurring in the winter and in the northern parts of the region. Nitrate seems to have both regional and local sources, because urban concentrations are higher than rural upwind concentrations. Ammonium nitrate forms when nitric acid reacts with ammonia, a process that is enhanced when temperatures are low and humidity is high. Nitric acid is a product of the oxidation of nitric oxide, a pollutant that is emitted by combustion processes.

Organic carbon is more consistent from season to season and city to city, although concentrations are generally slightly higher in the summer. Like nitrate, organic carbon has both regional and local components. Particulate organic carbon can be emitted directly from cars and other fuel combustion sources or formed in a secondary process as volatile organic gases react and condense. In rural areas, summer organic carbon has significant contributions from biogenic sources.

Precursor Sensitivity: Data from the Midwest ammonia monitoring network were analyzed with thermodynamic equilibrium models to assess the effect of changes in precursor gas concentrations on $PM_{2.5}$ concentrations (Blanchard, 2005b). These analyses indicate that particle formation responds in varying degrees to reductions in sulfate, nitric acid, and ammonia. Based on Figure 26, which shows $PM_{2.5}$ concentrations as a function of sulfate, nitric acid (HNO3), and ammonia (NH3), several key findings should be noted:

- $PM_{2.5}$ mass is sensitive to reductions in sulfate at all times of the year and all parts of the region. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases.

- $PM_{2.5}$ mass is also sensitive to reductions in nitric acid and ammonia. The greatest $PM_{2.5}$ decrease in response to nitric acid reductions occurs during the winter, when nitrate is a significant fraction of $PM_{2.5}$.

- Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

- Ammonia becomes more limiting as one moves from west to east across the region.

Examination of weekend/weekday difference in PM-nitrate and NOx concentrations in the Midwest demonstrate that reductions in local (urban) NOx lead to reductions, albeit non-proportional reductions, in PM-nitrate (Blanchard, 2004). This result is consistent with analyses of continuous PM-nitrate from several US cities, including St. Louis (Millstein, et al, 2007).

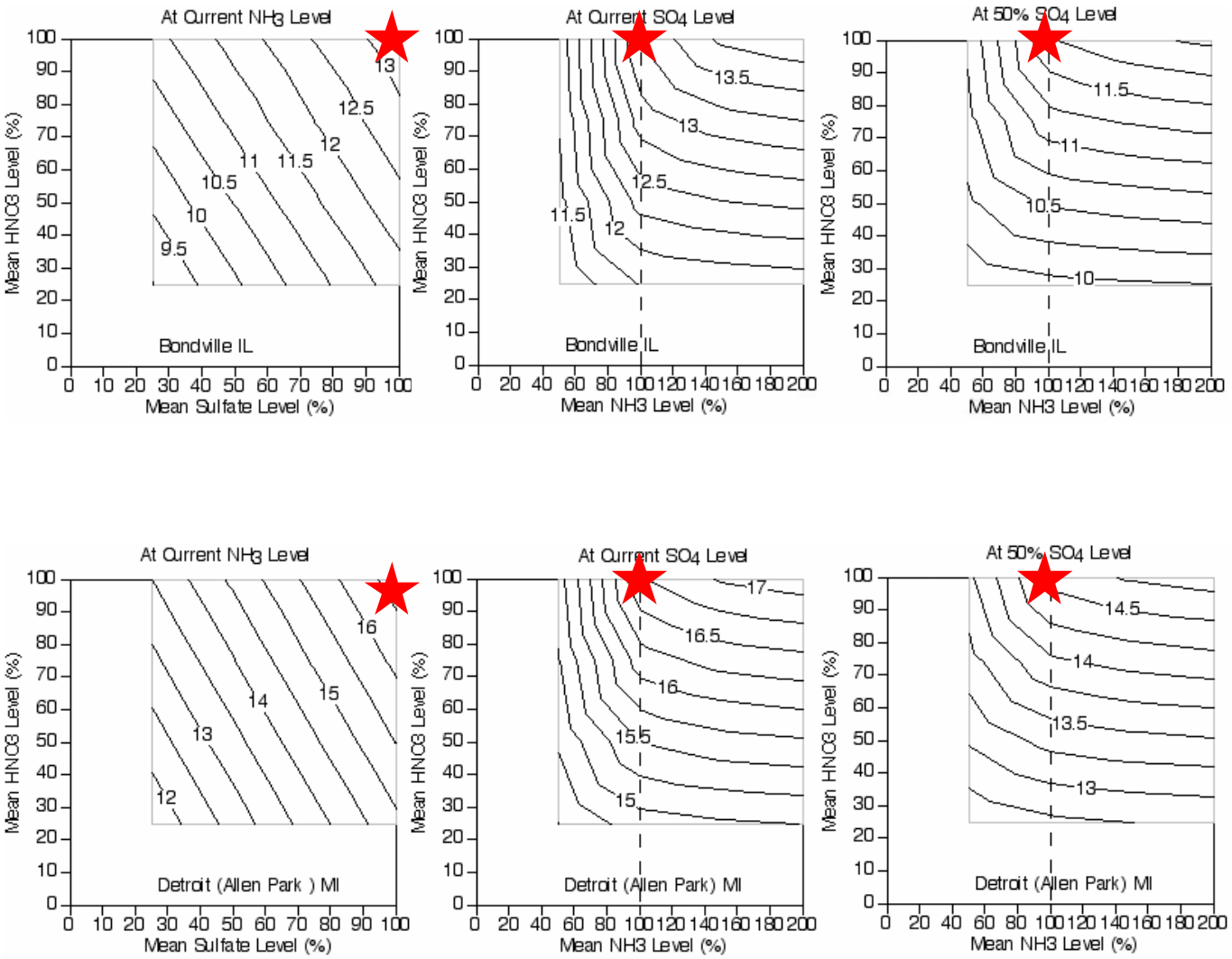


Figure 26. Predicted mean PM fine mass concentrations at Bondville, IL (top) and Detroit (Allen Park), MI (bottom) as functions of changes in sulfate, nitric acid (HNO3), and ammonia (NH3)

Note: starting at the baseline values (represented by the red star), either moving downward (reductions in nitric acid) or moving leftward (reductions in sulfate or ammonia) results in lower $PM_{2.5}$ values

Meteorology: $PM_{2.5}$ concentrations are not as strongly influenced by meteorology as ozone, but the two pollutants share some similar meteorological dependencies. In the summer, conditions that are conducive to ozone (hot temperatures, stagnant air masses, and low wind speeds due to stationary high pressure systems) also frequently give rise to high $PM_{2.5}$. In the case of PM, the reason is two-fold: (1) stagnation and limited mixing under these conditions cause $PM_{2.5}$ to build up, usually over several days, and (2) these conditions generally promote higher conversion of important precursors (SO_2 to SO_4) and higher emissions of some precursors, especially biogenic carbon. Wind direction is another strong determinant of $PM_{2.5}$; air transported from polluted source regions has higher concentrations.

Unlike ozone, $PM_{2.5}$ has occasional winter episodes. Conditions are similar to those for summer episodes, in that stationary high pressure and (seasonally) warm temperatures are usually factors. Winter episodes are also fueled by high humidity and low mixing heights.

$PM_{2.5}$ chemical species show noticeable transport influences. Trajectory analyses have demonstrated that high PM-sulfate is associated with air masses that traveled through the sulfate-rich Ohio River Valley (Poirot, et al, 2002 and Kenski, 2004). Likewise, high PM-nitrate is associated with air masses that traveled through the ammonia-rich Midwest. Figure 27 shows results from an ensemble trajectory analysis of 17 rural eastern IMPROVE sites.

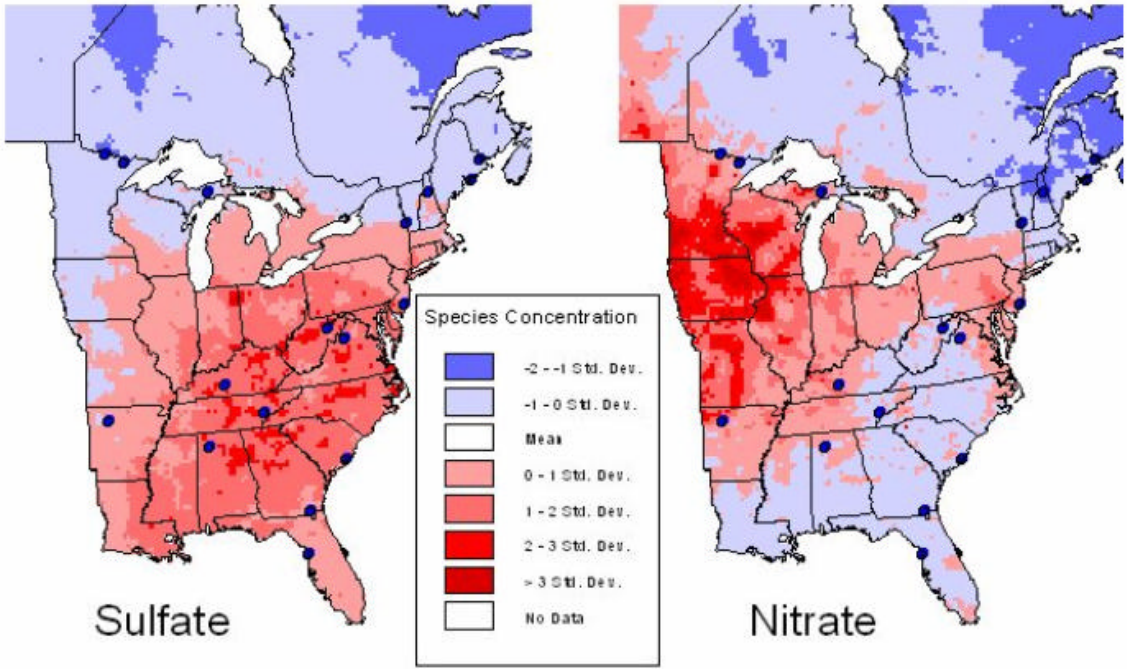


Figure 27. Sulfate and nitrate source regions based on ensemble trajectory analysis

When these results are considered together with analyses of precursor sensitivity (e.g., Figure 26), one possible conclusion is that ammonia control in the Midwest could be effective at reducing nitrate concentrations. The thermodynamic equilibrium modeling shows that ammonia reductions would reduce PM concentrations in the Midwest, but that nitric acid reductions are more effective when the probable reductions in future sulfate levels are considered.

Source Culpability: Three source apportionment studies were performed using speciated $PM_{2.5}$ monitoring data and statistical analysis methods (Hopke, 2005, STI, 2006, and STI, 2008). Figure 28 summarizes the source contributions from these studies. The studies show that a large portion of $PM_{2.5}$ mass consists of secondary, regional impacts, which cannot be attributed to individual facilities or sources (e.g., secondary sulfate, secondary nitrate, and secondary organic aerosols). Nevertheless, wind analyses (e.g., Figure 27) provide information on likely source regions. Regional- or national-scale control programs may be the most effective way to deal with these impacts. EPA's CAIR, for example, will provide for substantial reductions in SO2 emissions over the eastern half of the U.S., which will reduce sulfate (and $PM_{2.5}$) concentrations and improve visibility levels.

The studies also show that a smaller, yet significant portion of $PM_{2.5}$ mass is due to emissions from nearby (local) sources. Local (urban) excesses occur in many urban areas for organic and elemental carbon, crustal matter, and, in some cases, sulfate. The statistical analysis methods help to identify local sources and quantify their impact. This information is valuable to states wishing to develop control programs to address local impacts. A combination of national/regional-scale and local-scale emission reductions may be necessary to provide for attainment.

The carbon sources are not easily identified in complex urban environments. LADCO's Urban Organics Study (STI, 2006) identified four major sources of organic carbon: mobile sources, burning, industrial sources, and secondary organic aerosols. Additional sampling and analysis is underway in Cleveland and Detroit to provide further information on sources of organic carbon.

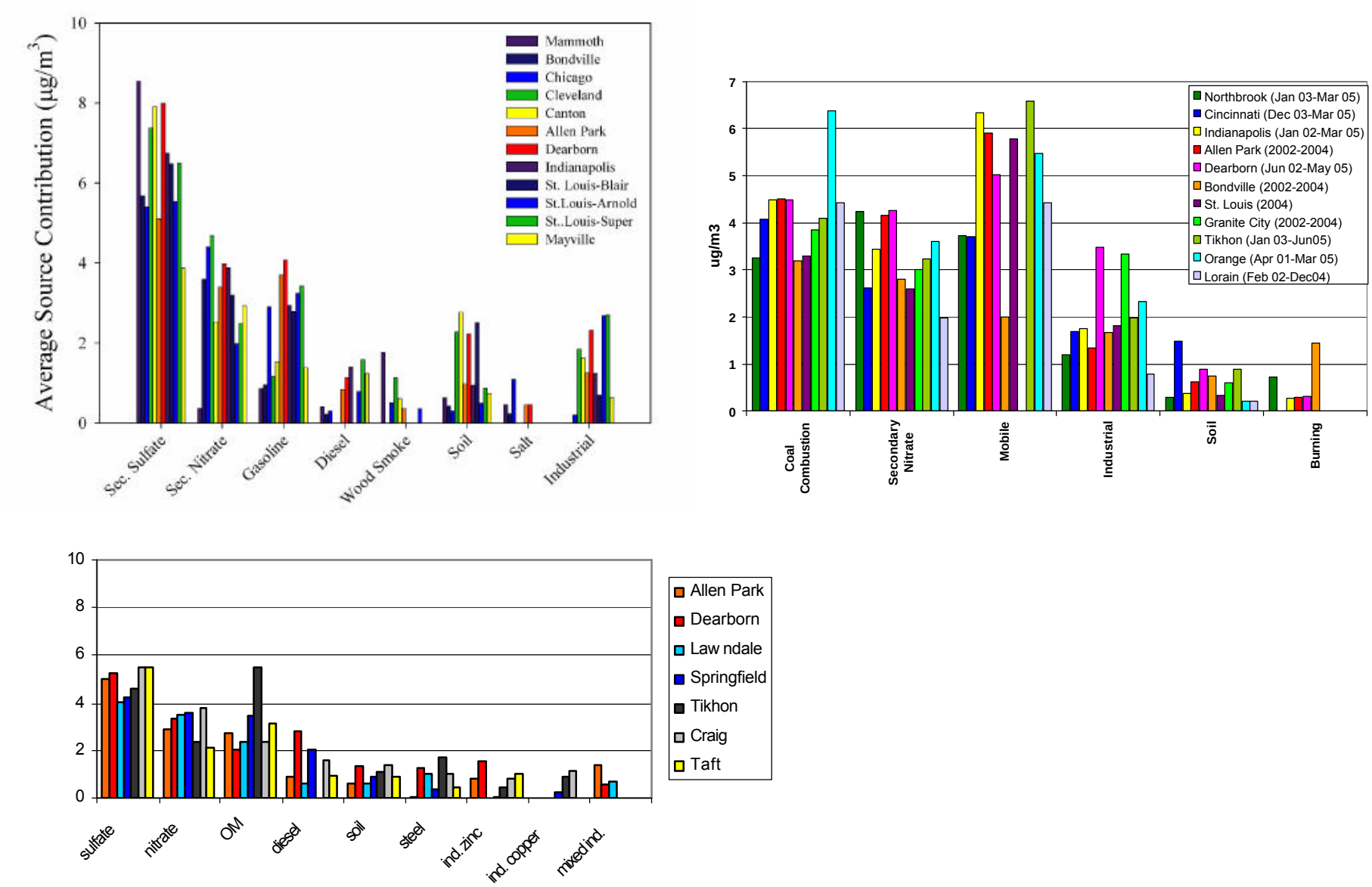


Figure 28. Major Source Contributions in the Midwest based on Hopke, 2005 (upper left), STI, 2006 (upper right), and STI, 2008 (lower left) (Note: the labeling of similar source types varies between studies – e.g., organic carbon/mobile sources are named gasoline and diesel by Hopke, mobile by STI 2006, and OM and diesel by STI 2008)

2.3 Haze

Section 169A of the Clean Air Act sets as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution". To implement this provision, in 1999, EPA adopted regulations to address regional haze visibility impairment (USEPA, 1999). EPA's rule requires states to "make reasonable progress toward meeting the national goal". Specifically, states must establish reasonable progress goals, which provide for improved visibility on the most impaired (20% worst) days sufficient to achieve natural conditions by the year 2064, and for no degradation on the least impaired (20% best) days.

The primary cause of impaired visibility in the Class I areas is pollution by fine particles that scatter light. The degree of impairment, which is expressed in terms of visual range, light extinction (1/Mm), or deciviews (dv), depends not just on the total $PM_{2.5}$ mass concentration, but also on the chemical composition of the particles and meteorological conditions.

Current Conditions: A map of the average light extinction values for the most impaired (20% worst) visibility days for the 5-year baseline period (2000-2004) is shown in Figure 29.

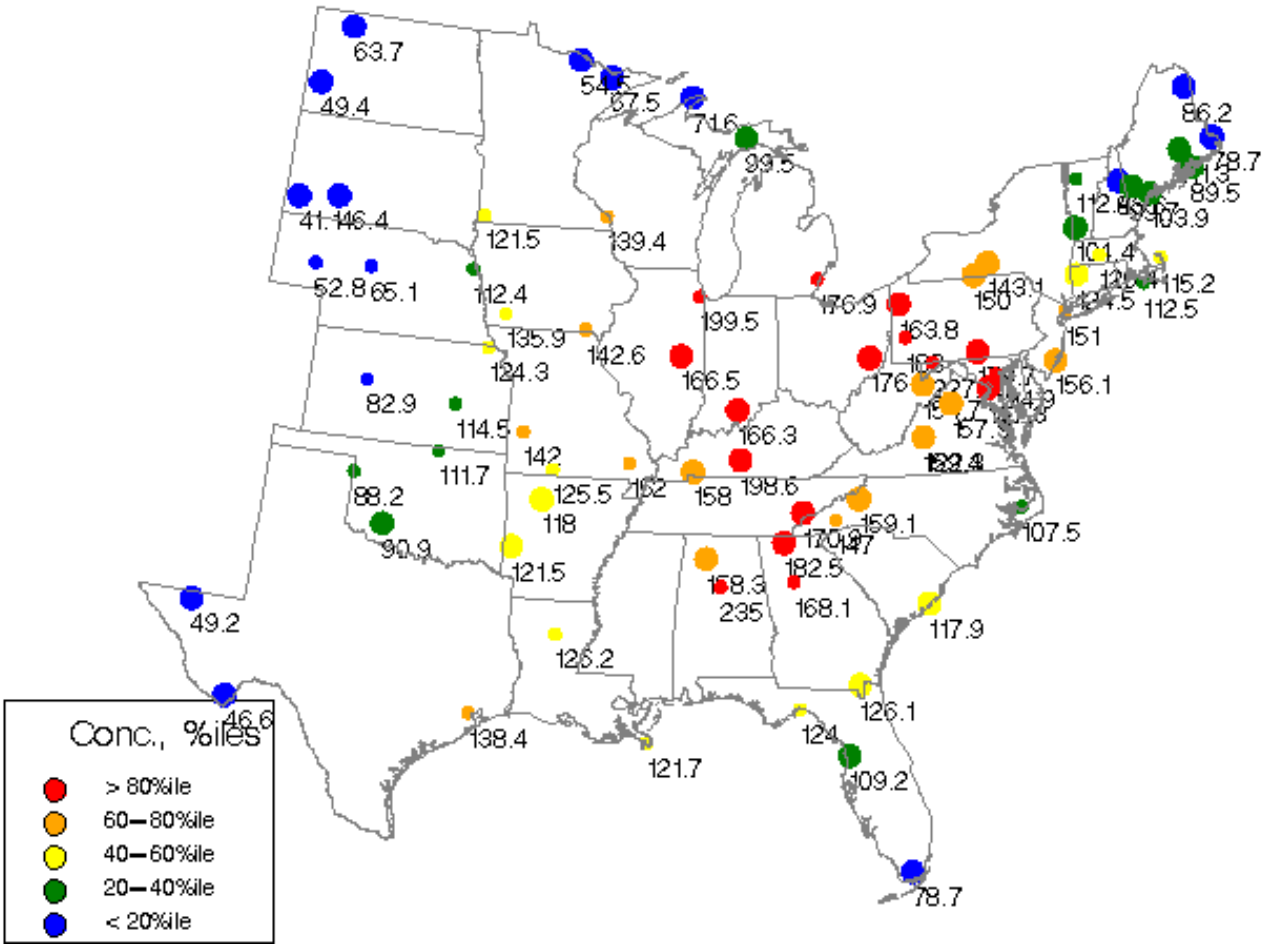


Figure 29. Baseline Visibility Levels for 20% Worst Days (2000 – 2004), units: Mm^{-1}

Initially, the baseline (2000 – 2004) visibility condition values were derived using the average for the 20% worst and 20% best days for each year, as reported on the VIEWS website: http://vista.cira.colostate.edu/views/Web/IMPROVE/SummaryData.aspx . These values were calculated using the original IMPROVE equation for reconstructed light extinction.

Three changes were made to the baseline calculations to produce a new set of values. First, the reconstructed light extinction equation was revised by the IMPROVE Steering Committee in 2005. The new IMPROVE equation was used to calculate updated baseline values.

Second, due to sampler problems, the 2002-2004 data for Boundary Waters were invalid for certain chemical species. (Note, sulfate and nitrate data were valid.) A "substituted" data set was developed by using values from Voyageurs for the invalid species.

Third, LADCO identified a number of days during 2000-2004 where data capture at the Class I monitors was incomplete (Kenski, 2007b). The missing data cause these days to be excluded from the baseline calculations. However, the light extinction due to the remaining measured species is significant (i.e., above the 80th percentile). It makes sense to include these days in the baseline calculations, because they are largely dominated by anthropogenic sources. (Only one of these days is driven by high organic carbon, which might indicate non-anthropogenic aerosol from wildfires.) As seen in Table 3, inclusion of these days in the baseline calculation results in a small, but measurable, effect on the baseline values (i.e., values increase from 0.2 to 0.8 dv).

Table 3. Average of 20% worst days, with and without missing data days

	Average Worst Day DV, per RHR	Average Worst Day DV, with Missing Data Days	Difference
BOWA	19.59	19.86	0.27
ISLE	20.74	21.59	0.85
SENE	24.16	24.38	0.22
VOYA	19.27	19.48	0.21

A summary of the initial and updated baseline values for the Class I areas in northern Michigan and northern Minnesota are presented in Table 4. The updated baseline values reflect the most current, complete understanding of visibility impairing effects and, as such, will be used for SIP planning purposes.

Table 4. Summary of visibility metrics (deciviews) for northern Class I areas

Old IMPROVE Equation (Cite: VIEWS, November 2005)									
		20% Worst Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**	**2018 URI Value**	**Natural Conditions**
Voyageurs		18.50	18.00	19.00	19.20	17.60	18.46	16.74	11.09
BWCA		19.85	19.99	19.68	19.73	17.65	19.38	17.47	11.21
Isle Royale		20.00	22.00	20.80	19.50	19.10	20.28	18.17	11.22
Seney		22.60	24.90	24.00	23.80	22.60	23.58	20.73	11.37
		20% Best Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**		**Natural Conditions**
Voyageurs		6.30	6.20	6.70	7.00	5.40	6.32		3.41
BWCA		5.90	6.52	6.93	6.67	5.61	6.33		3.53
Isle Royale		5.70	6.40	6.40	6.30	5.30	6.02		3.54
Seney		5.80	6.10	7.30	7.50	5.80	6.50		3.69
New IMPROVE Equation (Cite: VIEWS, March 2006)									
		20% Worst Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**	**2018 URI Value**	**Natural Conditions**
Voyageurs		19.55	18.57	20.14	20.25	18.87	19.48	17.74	12.05
BWCA		20.20	20.04	20.76	20.13	18.18	19.86	17.94	11.61
Isle Royale		20.53	23.07	21.97	22.35	20.02	21.59	19.43	12.36
Seney		22.94	25.91	25.38	24.48	23.15	24.37	21.64	12.65
		20% Best Days							
		2000	**2001**	**2002**	**2003**	**2004**	**Baseline Value**		**Natural Conditions**
Voyageurs		7.01	7.12	7.53	7.68	6.37	7.14		4.26
BWCA		6.00	6.92	7.00	6.45	5.77	6.43		3.42
Isle Royale		6.49	7.16	7.07	6.99	6.12	6.77		3.72
Seney		6.50	6.78	7.82	8.01	6.58	7.14		3.73

Notes: (1) BWCA values for 2002 - 2004 reflect "substituted" data.
(2) New IMPROVE equation values include Kenski, 2007 adjustment for missing days

URI = uniform rate of improvement

As noted above, the goal of the visibility program is to achieve natural conditions. Initially, the natural conditions values for each Class I area were taken directly from EPA guidance (EPA, 2003). These values were calculated using the original IMPROVE equation. This equation was revised by the IMPROVE Steering Committee in 2005, and the new IMPROVE equation was used to calculate updated natural conditions values. The updated values are reported on the VIEWS website.

A summary of the initial and updated natural conditions values are presented in Table 4. The updated natural conditions values (based on the new IMPROVE equation) will be used for SIP planning purposes.

Data Variability: For the four northern Class I areas, the most important $PM_{2.5}$ chemical species are ammonium sulfate, ammonium nitrate, and organic carbon. The contribution of these species on the 20% best and 20% worst visibility days (based on 2000 – 2004 data) is provided in Figure 30. For the 20% worst visibility days, the contributions are: sulfate = 35-55%, nitrate = 25-30%, and organic carbon = 12-22%. Although the chemical composition is similar, sulfate increases in importance from west to east and concentrations are highest at Seney (the easternmost site). It should also be noted that sulfate and nitrate contribute more to light extinction than to $PM_{2.5}$ mass because of their hygroscopic properties.

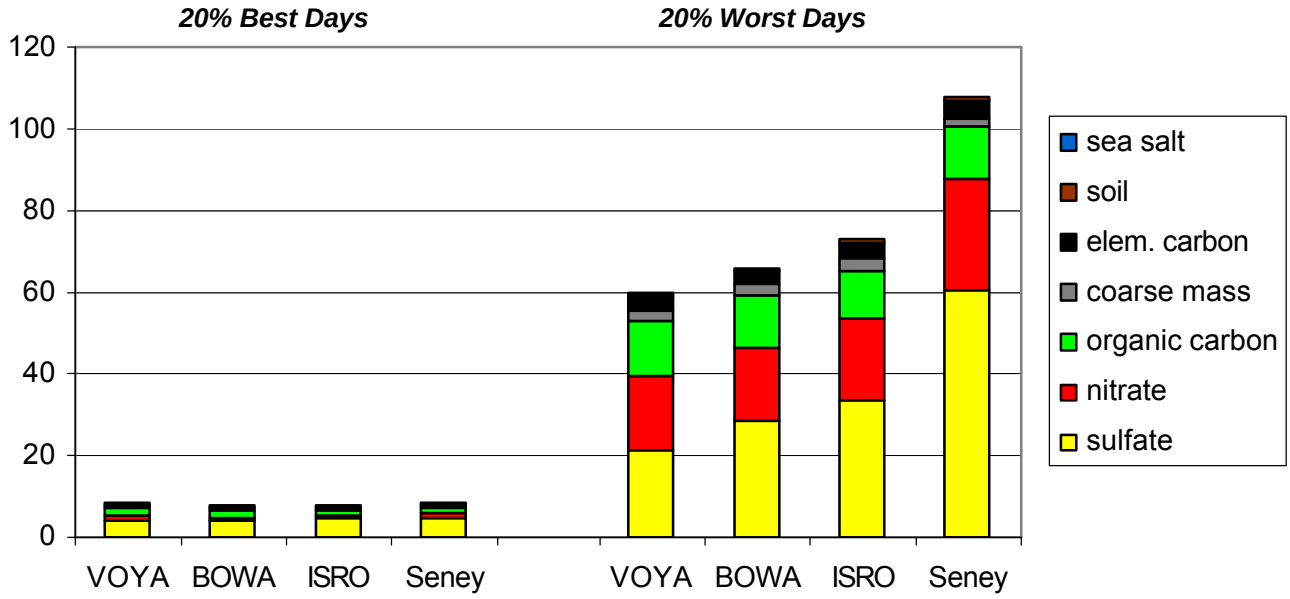


Figure 30. Chemical composition of light extinction for 20% best visibility days (left) and 20% worst visibility days (right) in terms of Mm^{-1}

Analysis of $PM_{2.5}$ mass and chemical species for rural IMPROVE (and IMPROVE-protocol) sites in the eastern U.S. showed a high degree of correlation between $PM_{2.5}$-mass, sulfate, and nitrate levels (see Figure 31). The Class I sites in northern Michigan and northern Minnesota, in particular, are highly correlated for $PM_{2.5}$ mass, sulfates, and organic carbon mass (AER, 2004).

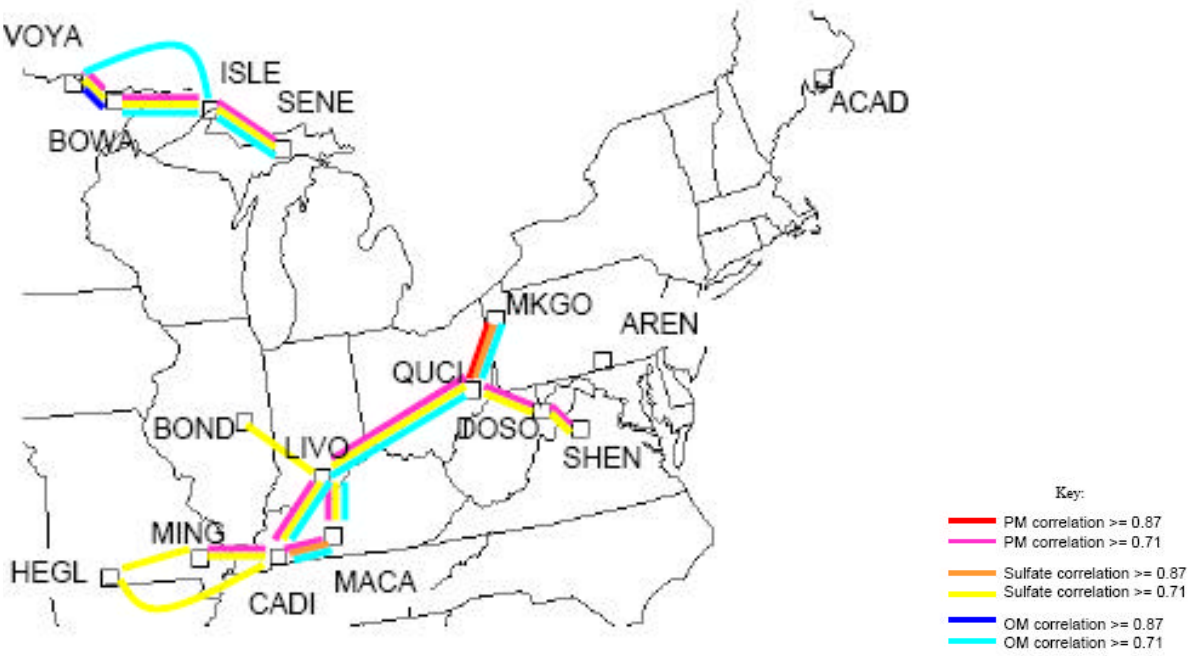


Figure 31. Correlations among IMPROVE (and IMPROVE-protocol) monitoring sites in Eastern U.S.

Long-term trends at Boundary Waters (the only regional site with a sufficient data record) show significant decreases in total $PM_{2.5}$ (-0.005 ug/year) and SO4 (-0.04 ug/year) and an increase in NO3 (+0.01 ug/year). These $PM_{2.5}$ and SO4 trends are generally consistent with long-term trends at other IMPROVE sites in the eastern U.S., which have shown widespread decreases in SO4 and $PM_{2.5}$ (DeBell, et al, 2006). Detecting changes in nitrate has been hampered by uncertainties in the IMPROVE data for particular years and, thus, this estimate should be considered tentative.

Haze in the Midwest Class I areas has no strong seasonal pattern. Poor visibility days occur throughout the year, as indicated in Figure 32. (Note, in contrast, other parts of the country, such as Shenandoah National Park in Virginia, show a strong tendency for the worst air quality days to occur in the summer months.) This figure and Figure 33 (which presents the monthly average light extinction values based on all sampling days) also show that sulfate and organic carbon concentrations are higher in the summer, and nitrate concentrations are higher in the winter, suggesting the importance of different sources and meteorological conditions at different times of the year.

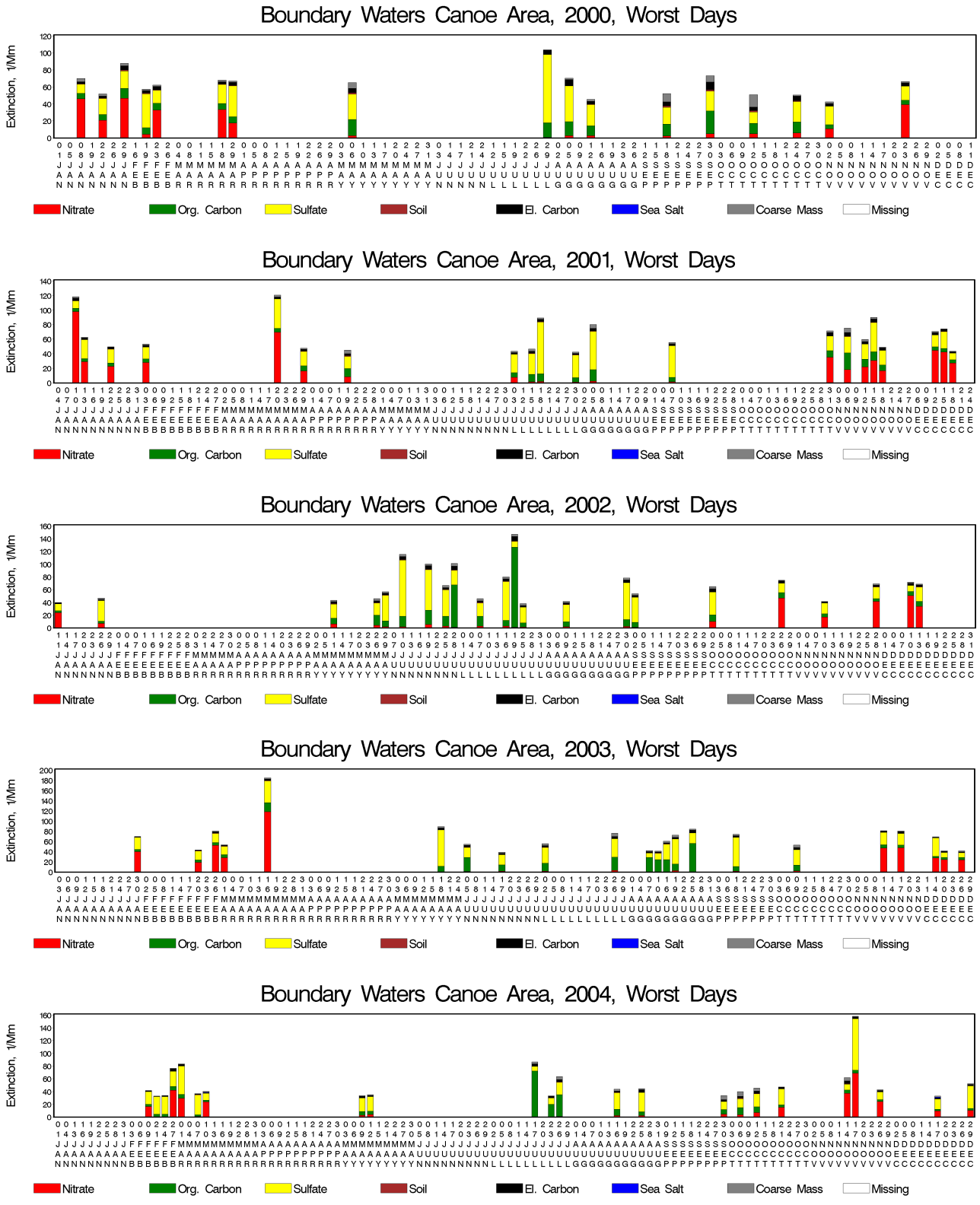


Figure 32. Daily light extinction values for 20% worst days at Boundary Waters (2000 – 2004)

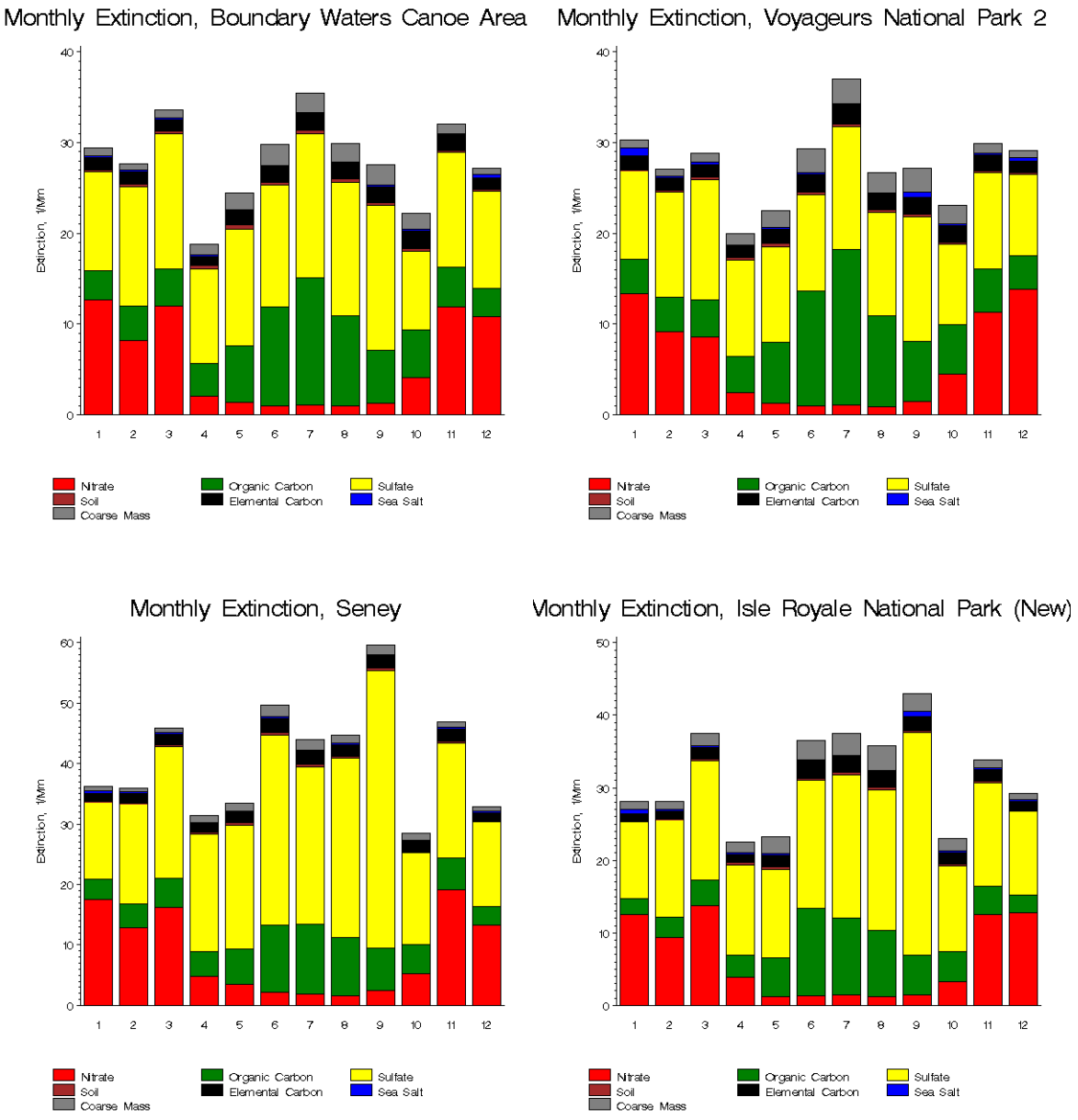


Figure 33. Monthly average light extinction values for northern Class I areas

Precursor Sensitivity: Results from two analyses using thermodynamic equilibrium models provide information on the effect of changes in precursor concentrations on $PM_{2.5}$ concentrations (and, in turn, visibility levels) in the northern Class I areas. First, a preliminary analysis using data collected at Seney indicated that $PM_{2.5}$ there is most sensitive to reductions in sulfate, but is also sensitive to reductions in nitric acid (Blanchard, 2004).

Second, an analysis was performed using data from the Midwest ammonia monitoring network for a site in Minnesota -- Great River Bluffs, which is the closest ammonia monitoring site to the northern Class I areas (Blanchard, 2005b). Figure 34 shows $PM_{2.5}$ concentrations as a function of sulfate, nitric acid (HNO3), and ammonia (NH3). Reductions in sulfate (i.e., movement to the left of baseline value [represented by the red star]), as well as reductions in nitric acid (i.e., movement downward) and NH3 (i.e., movement to the left), result in lower $PM_{2.5}$ concentrations. Thus, reductions in sulfate, nitric acid, and ammonia will lower $PM_{2.5}$ concentrations and improve visibility in the northern Class I areas.

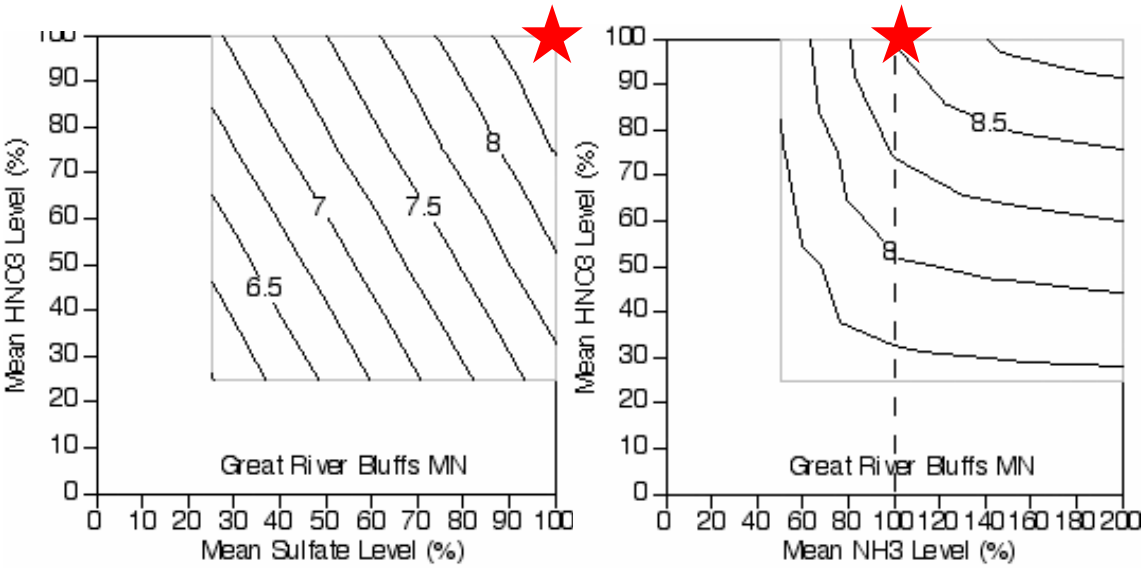


Figure 34. Predicted $PM_{2.5}$ mass concentrations at Great River Bluffs, MN as functions of changes in sulfate, nitric acid, and ammonia

Meteorology and Transport: The role of meteorology in haze is complex. Wind speed and wind direction govern the movement of air masses from polluted areas to the cleaner wilderness areas. As noted above, increasing humidity increases the efficiency with which sulfate and nitrate aerosols scatter light. Temperature and humidity together govern whether ammonium nitrate can form from its precursor gases, nitric acid and ammonia. Temperature and sunlight also play an indirect role in emissions of biogenic organic species that condense to form particulate organic matter; emissions increase in the summer daylight hours.

Trajectory analyses were performed to understand transport patterns for the 20% worst and 20% best visibility days. The composite results for the four northern Class I areas are provided in Figure 35. The orange areas are where the air is most likely to come from, and the green areas are where the air is least likely to come from. As can be seen, bad air days are generally associated with transport from regions located to the south, and good air days with transport from Canada.

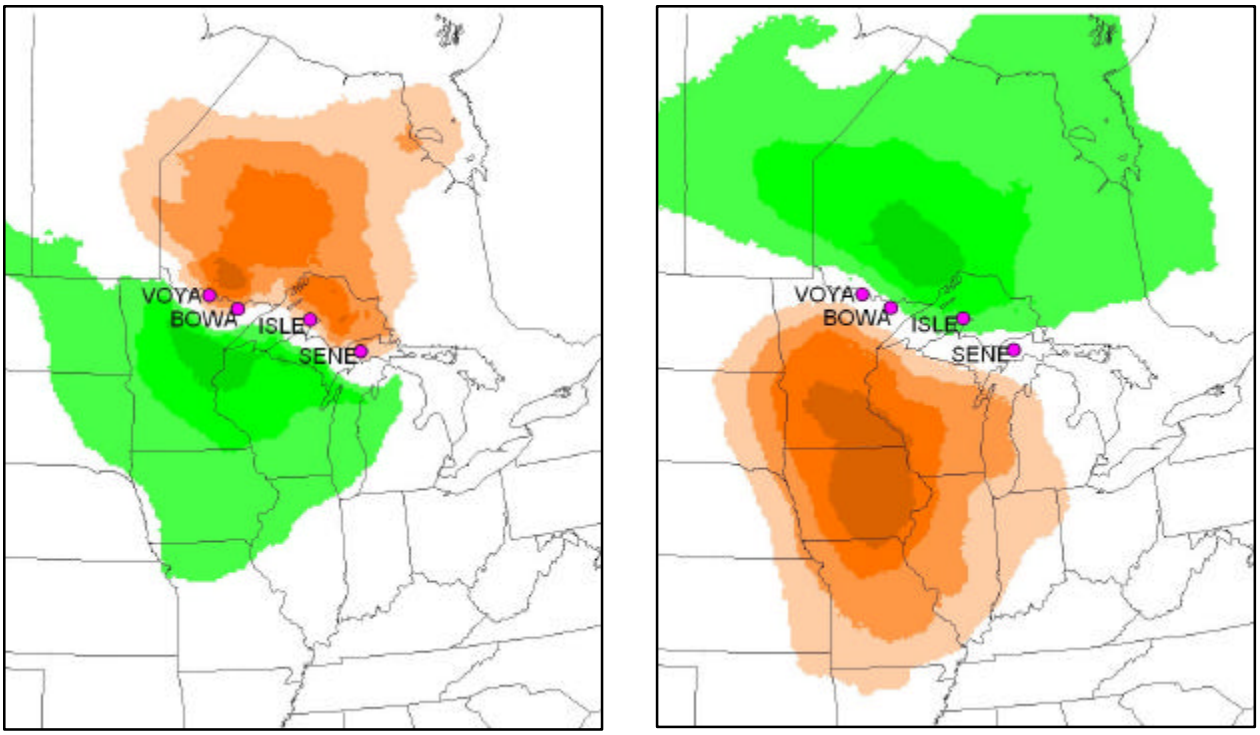


Figure 35. Composite back trajectories for light extinction- 20% best visibility days (left) and 20% worst visibility days (right) (2000 – 2005)

Source Culpability: Air quality data analyses (including the trajectory analyses above) and dispersion modeling were used to provide information on source region and source sector contributions to regional haze in the northern Class I areas (see MRPO, 2008). Based on this information, the most important contributing states are Michigan, Minnesota, and Wisconsin, as well as Missouri, North Dakota, Iowa, Indiana and Illinois (see, for example, Figure 35 above). The most important contributing pollutants and source sectors are SO2 emissions from electrical generating units (EGUs) and certain non-EGUs, which lead to sulfate formation, and NOx emissions from a variety of source types (e.g., motor vehicles), which lead to nitrate formation. Ammonia emissions from livestock waste and fertilizer applications are also important, especially for nitrate formation.

A source apportionment study was performed using monitoring data from Boundary Waters and statistical analysis methods (DRI, 2005). The study shows that a large portion of $PM_{2.5}$ mass consists of secondary, regional impacts, which cannot be attributed to individual facilities or sources (e.g., secondary sulfate, secondary nitrate, and secondary organic aerosols). Industrial sources contribute about 3-4% and mobile sources about 4-7% to $PM_{2.5}$ mass.

A special study was performed in Seney to identify sources of organic carbon (Sheesley, et al, 2004). As seen in Figure 36, the highest $PM_{2.5}$ concentrations occurred during the summer, with organic carbon being the dominant species. The higher summer organic carbon concentrations were attributed mostly to secondary organic aerosols of biogenic origin because of the lack of primary emission markers, and concentrations of know biogenic-related species (e.g., pinonic acid – see Figure 36) were also high during the summer.

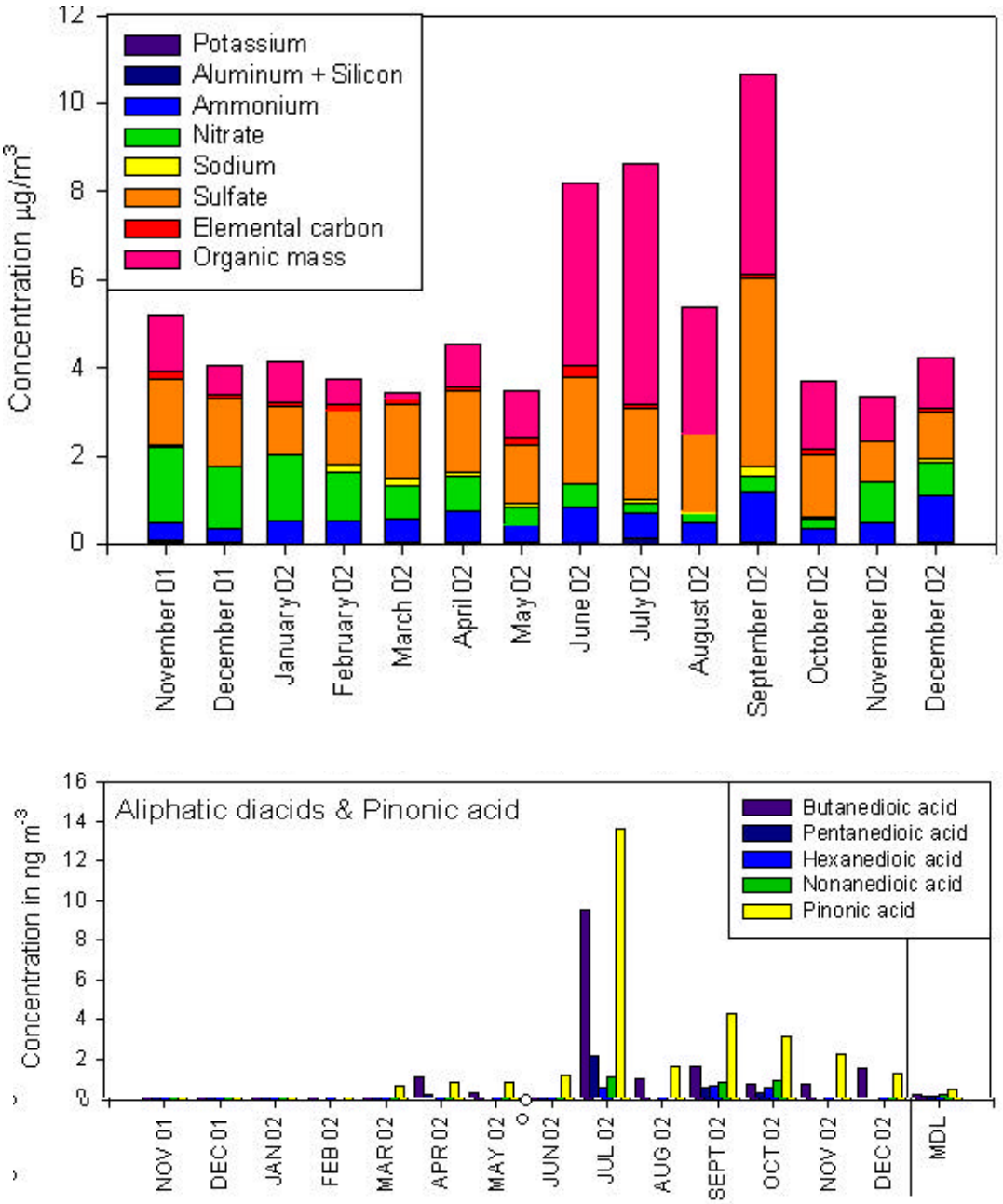


Figure 36. Monthly concentrations of $PM_{2.5}$ species (top), and secondary and biogenic-related organic carbon species in Seney (bottom)

Although the Seney study showed that biomass burning was a relatively small contributor to organic carbon on an annual average basis, episodic impacts are apparent (see, for example, high organic carbon days in Figure 32). To assess further whether burning is a significant contributor to visibility impairment in the northern Class I areas, the $PM_{2.5}$ chemical speciation data were examined for days with high organic carbon and elemental carbon concentrations, which are indicative of biomass burning impacts. Only a handful of such days were identified:

Table 5. Days with high OC and EC concentrations in northern Class I areas

Site	2000	2001	2002	2003	2004
Voyageurs	---	---	Jun 1	Aug 25	Jul 17
			Jun 28		
			Jul 19		
Boundary Waters	---	---	Jun 28	Aug 25	Jul 17
			Jul 19		
Isle Royale	---	---	Jun 1	Aug 25	---
			Jun 28		
Seney	---	---	Jun 28	---	---

Back trajectories on these days point mostly to wildfires in Canada. Elimination of these high organic carbon concentration days has a small effect in lowering the baseline visibility levels in the northern Class I areas (i.e., Minnesota Class I areas change by about 0.3 deciviews and Michigan Class I areas change by less than 0.2 deciviews). This suggests that fire activity, although significant on a few days, is on average a relatively small contributor to visibility impairment in the northern Class I areas.

In summary, these analyses show that organic carbon in the northern Class I is largely uncontrollable.

Section 3.0 Air Quality Modeling

Air quality models are relied on by federal and state regulatory agencies to support their planning efforts. Used properly, models can assist policy makers in deciding which control programs are most effective in improving air quality, and meeting specific goals and objectives. For example, models can be used to conduct "what if" analyses, which provide information for policy makers on the effectiveness of candidate control programs.

The modeling analyses were conducted in accordance with EPA's modeling guidelines (EPA, 2007a). Further details of the modeling are provided in two protocol documents: LADCO, 2007a and LADCO, 2007b.

This section reviews the development and evaluation of the modeling system used for the multi-pollutant analyses. Application of the modeling system (i.e., attainment demonstration for ozone and $PM_{2.5}$, and reasonable progress assessment for haze) is covered in the following sections.

3.1 Selection of Base Year

Two base years were used in the modeling analyses: 2002 and 2005. EPA's modeling guidance recommends using 2002 as the baseline inventory year, but also allows for use of an alternative baseline inventory year, especially a more recent year. Initially, LADCO conducted modeling with a 2002 base year (i.e., Base K/Round 4 modeling, which was completed in 2006). A decision was subsequently made to conduct modeling with a 2005 base year (i.e., Base M/Round 5, which was completed in 2007). As discussed in the previous section, 2002 and 2005 both had above normal ozone conducive conditions, although 2002 was more severe compared to 2005. Examination of multiple base years provides for a more complete technical assessment. Both sets of model runs are discussed in this document.

3.2 Future Years of Interest

To address the multiple attainment requirements for ozone and $PM_{2.5}$, and reasonable progress goals for regional haze, several future years are of interest:

- 2008 Planning year for ozone basic nonattainment areas (attainment date 2009)[8]
- 2009 Planning year for ozone moderate nonattainment areas and $PM_{2.5}$ nonattainment areas (attainment date 2010)
- 2012 Planning year for ozone moderate nonattainment areas and $PM_{2.5}$ nonattainment areas, with 3-year extension (attainment date 2013)
- 2018 First milestone year for regional haze planning

[8] According to USEPA's ozone implementation rule (USEPA, 2005), emission reductions needed for attainment must be implemented by the beginning of the ozone season immediately preceding the area's attainment date. The PM2.5 implementation rule contains similar provisions – i.e., emission reductions should be in place by the beginning of the year preceding the attainment date (USEPA, 2007c). The logic for requiring emissions reductions by the year (or season) immediately preceding the attainment year follows from language in the Clean Air Act, and the ability for an area to receive up to two 1-year extensions. Therefore, emissions in the year preceding the attainment year should be at a level that is consistent with attainment. It also follows that the year preceding the attainment year should be modeled for attainment planning purposes.

Detailed emissions inventories were developed for 2009 and 2018. To support modeling for other future years, less rigorous emissions processing was conducted (e.g., 2012 emissions were estimated for several source sectors by interpolating between 2009 and 2018 emissions).

3.3 Modeling System

The air quality analyses were conducted with the CAMx model, with emissions and meteorology generated using EMS (and CONCEPT) and MM5, respectively. The selection of CAMx as the primary model is based on several factors: performance, operator considerations (e.g., ease of application and resource requirements), technical support and documentation, model extensions (e.g., 2-way nested grids, process analysis, source apportionment, and plume-in-grid), and model science. CAMx model set-up for Base M and Base K is summarized below:

Base M (2005)	Base K (2002)
• CAMx v4.50	* CAMx 4.30
• CB05 gas phase chemistry	* CB-IV with updated gas-phase chemistry
• SOA chemistry updates	* No SOA chemistry updates
• AERMOD dry deposition scheme	* Wesley-based dry deposition
• ISORROPIA inorganic chemistry	• ISORROPIA inorganic chemistry
• SOAP organic chemistry	• SOAP organic chemistry
• RADM aqueous phase chemistry	• RADM aqueous phase chemistry
• PPM horizontal transport	• PPM horizontal transport

3.4 Domain/Grid Resolution

The National RPO grid projection was used for this modeling. A subset of the RPO domain was used for the LADCO modeling. For $PM_{2.5}$ and haze, the large eastern U.S. grid at 36 km (see box on right side of Figure 36) was used. A $PM_{2.5}$ sensitivity run was also performed for this domain at 12 km. For ozone, the smaller grid at 12 km (see shaded portion of the box on the right side of Figure 37) was used for most model runs. An ozone sensitivity run was also performed with a 4km sub-grid over the Lake Michigan area and Detroit/Cleveland.

The vertical resolution in the air quality model consists of 16 layers extending up to 15 km, with higher resolution in the boundary layer.

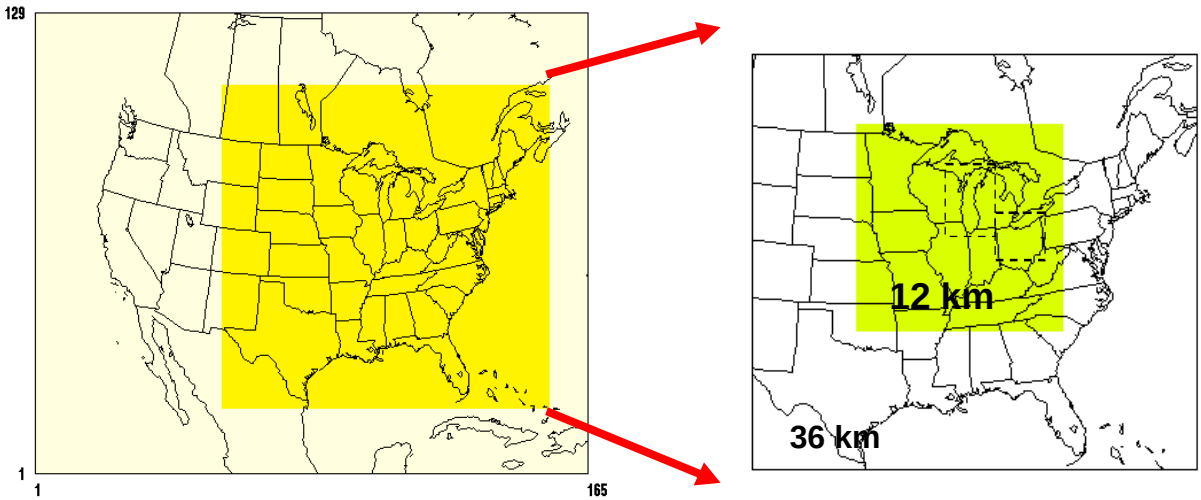


Figure 37. Modeling grids – RPO domain (left) and LADCO modeling domain (right)

3.5 Model Inputs: Meteorology

Meteorological inputs were derived using the Fifth-Generation NCAR/Penn State Meteorological Model (MM5) – version 3.6.3 for the years 2001–2003, and version 3.7 for the year 2005. The MM5 modeling domains are consistent with the National RPO grid projections (see Figure 38).

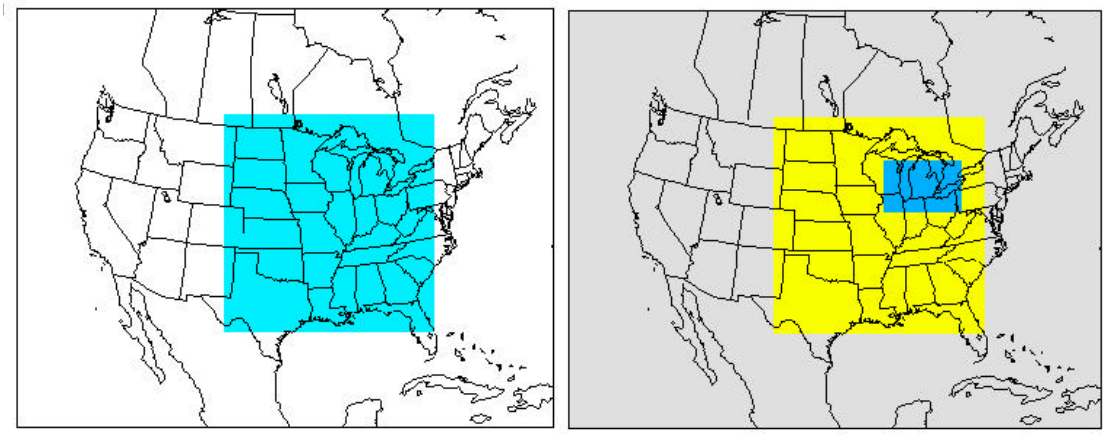


Figure 38. MM5 modeling domain for 2001-2003 (left) and 2005 (right)

The annual 2002 36 km MM5 simulation was completed by Iowa DNR. The 36/12 km 2-way nested simulation for the summers of 2001, 2002, and 2003 were conducted jointly by Illinois EPA and LADCO. The 36 km non-summer portion of the annual 2003 simulation was conducted by Wisconsin DNR. The annual 2005 36/12 km (and summer season 4 km) MM5 modeling was completed by Alpine Geophysics. Wisconsin DNR also completed 36/12 km MM5 runs for the summer season of 2005.

Model performance was assessed quantitatively with the METSTAT tool from Environ. The metrics used to quantify model performance include mean observation, mean prediction, bias, gross error, root mean square error, and index of agreement. Model performance metrics were calculated for several sub-regions of the modeling domain (Figure 39) and represent hourly spatial averages of multiple monitor locations. Additional analysis of rainfall is done on a monthly basis.

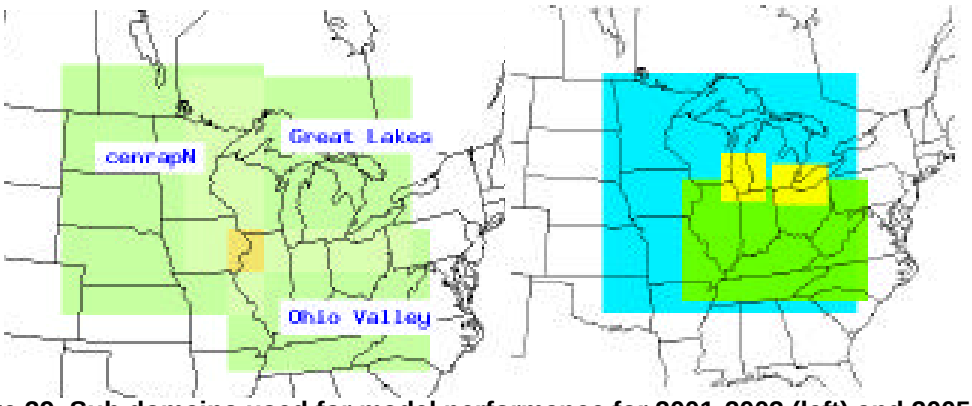


Figure 39. Sub-domains used for model performance for 2001-2003 (left) and 2005 (right)

A summary of the performance evaluation results for the meteorological modeling is provided below. Further details are provided in two summary reports (LADCO, 2005 and LADCO, 2007c).

Temperature: The biggest issue with the performance in the upper Midwest is the existence of a cool diurnal temperature bias in the winter and warm temperature bias over night during the summer (see Figure 40). These features are common to other annual MM5 simulations for the central United States and do not appear to adversely affect model performance.

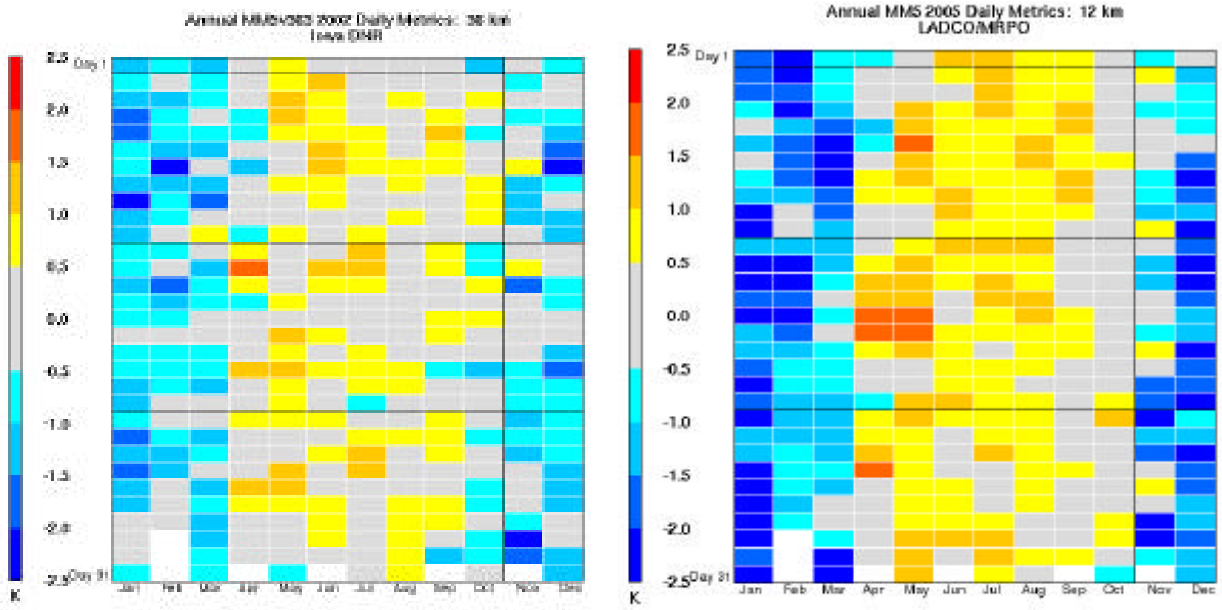


Figure 40. Daily temperature bias for 2002 (left) and 2005 (right) with hotter colors (yellow/orange/red) representing overestimates and cooler colors (blues) representing underestimates

Note: months are represented from left to right (January to December) and days are represented from top to bottom (1 to 30(31) – i.e., upper left hand corner is January 1 and lower right hand corner is December 31

Wind Fields: The wind fields are generally good. Wind speed bias is less than 0.5 m/sec and wind speed error is consistently between 1.0 and 1.5 m/sec. Wind direction error is generally within 15-30 degrees.

Mixing Ratio: The mixing ratio (a measure of humidity) is over-predicted in the late spring and summer months, and mixing ratio error is highest during this period. There is little bias and error during the cooler months when there is less moisture in the air.

Rainfall: The modeled and observed rainfall totals show good agreement spatially and in terms of magnitude in the winter, fall, and early spring months. There are, however, large over-predictions of rainfall in the late spring and summer months (see Figure 41). These over-predictions are seen spatially and in magnitude over the entire domain, particularly in the Southeast United States, and are likely due to excessive convective rainfall being predicted in MM5. This over-prediction of rainfall in MM5 does not necessarily translate into over-prediction of wet deposition in the photochemical model. CAMx does not explicitly use the convective and non-convective rainfall output by MM5, but estimates wet scavenging by hydrometeors using cloud, ice, snow, and rain water mixing ratios output by MM5. Nevertheless, this could have an effect on model performance for $PM_{2.5}$, as discussed in Section 3.7, and may warrant further attention.

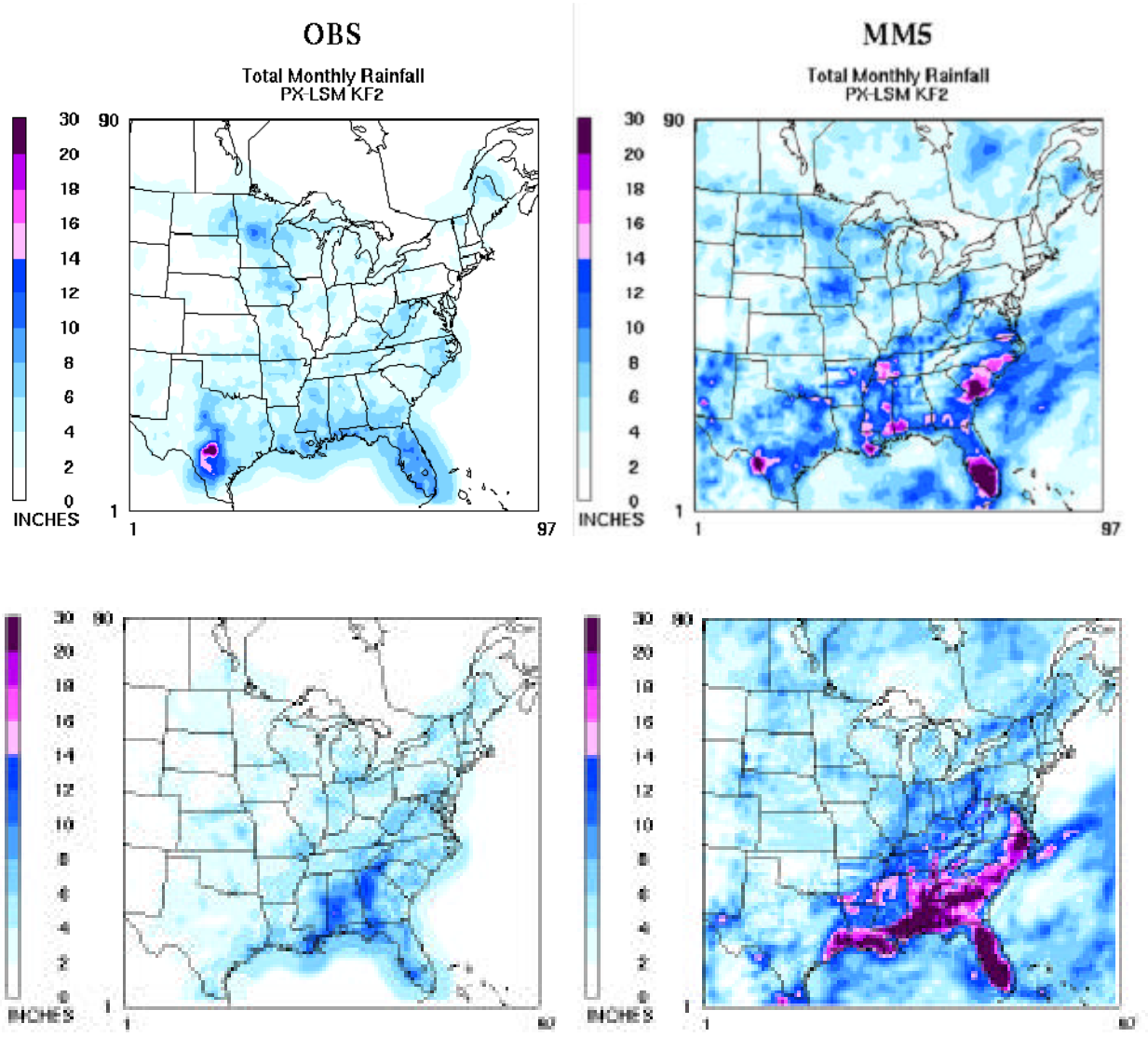


Figure 41. Comparison of observed (left column) and modeled (right column) monthly rainfall for July 2002 (top) and July 2005 (bottom)

3.6 Model Inputs: Emissions

Emission inventories were prepared for two base years: 2002 (Base K) and 2005 (Base M), and several future years: 2008, 2009, 2012, and 2018. Further details of the emission inventories are provided in two summary reports (LADCO, 2006a and LADCO, 2008a) and the following pages of the LADCO web site:

http://www.ladco.org/tech/emis/basek/BaseK_Reports.htm
http://www.ladco.org/tech/emis/r5/round5_reports.htm

For on-road, nonroad, ammonia, and biogenic sources, emissions were estimated by models. For the other sectors (point sources, area sources, and MAR [commercial marine, aircraft, and railroads]), emissions were prepared using data supplied by the LADCO States and other RPOs.

Base Year Emissions: State and source sector emission summaries for 2002 (Base K) and 2005 (Base M) are compared in Figure 42. Additional detail is provided in Tables 6a (all sectors – tons per day) and 6b (EGUs – tons per year).

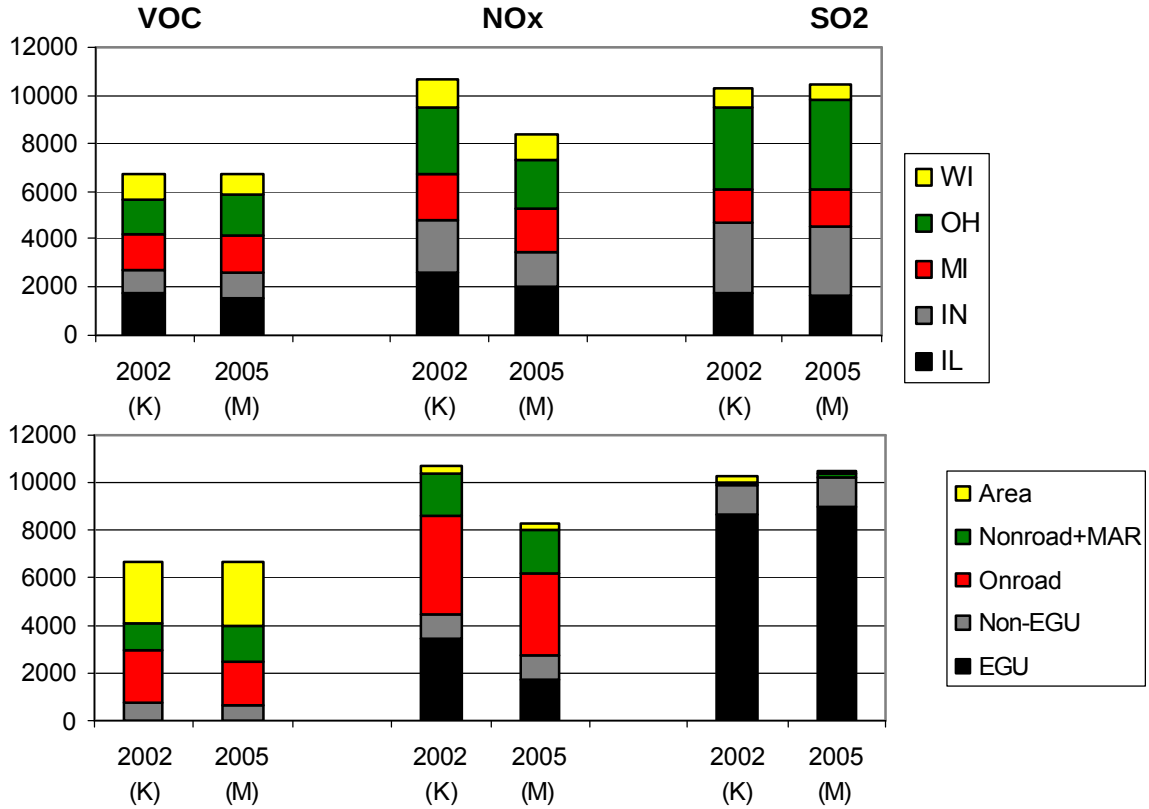


Figure 42. Base K and Base M emissions for 5-state LADCO region by state (top) and source sector (bottom), units: tons per summer weekday

A summary of the base year emissions by sector for the LADCO States is provided below.

	VOC	Base M	BaseK	Base M	BaseK	BaseK	Base M		NOx	Base M	BaseK	Base M	BaseK	BaseK	Base M		SOX	Base M	BaseK	Base M	BaseK	BaseK	Base M		PM2.5	Base M	BaseK	Base M	BaseK	BaseK	Base M
July	2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018
Nonroad																															
IL	224	321	164	257	149	130	213		324	333	263	275	224	154	155		31	33	5	5	0.6	0.4	0.4			30		24			14
IN	125	195	94	160	95	95	128		178	191	142	158	141	141	89		17	19	3	3	3	0.3	0.2			17		13			7
MI	348	414	307	350	276	222	271		205	239	159	197	133	93	112		19	22	3	3	0.5	0.3	0.3			22		18			11
OH	222	356	161	294	145	126	238		253	304	195	246	162	109	135		23	29	4	5	0.5	0.3	0.4			27		22			13
WI	214	238	194	203	175	140	157		145	157	114	129	97	69	77		13	15	2	2	0.3	0.2	0.2			14		12			7
5-State Total	1133	1524	920	1264	840	713	1007		1105	1224	873	1005	757	566	568		103	118	17	18	4.9	1.5	1.5			110		89			52
U.S. Total	8463	9815	5442	8448		5244	6581		6041	9060	6057	8120		5832	5100		505	654	117	153		104	13			573		750			475
MAR																															
IL	10	11	10	10	10	10	6		277	246	201	228	195	186	165		0	22	0	19	0	0	17			7		6			4
IN	5	5	5	5	5	5	3		123	93	89	87	87	84	65		0.2	8	0.2	7	0.2	0.2	6			2		2			2
MI	7	7	7	7	7	8	7		114	87	112	82	111	110	65		0.6	21	0.7	14	0.7	0.8	8			3		3			2
OH	8	7	8	7	8	8	5		177	134	128	126	126	122	94		0.4	14	0.3	12	0.3	0.3	10			4		4			2
WI	4	4	4	4	4	4	3		79	58	59	54	59	57	41		12.7	8	9.5	6	9.5	8.7	5			2		2			1
5-State Total	34	34	34	33	34	35	24		770	618	589	577	578	559	430		13.9	73	10.7	58	10.7	10	46			18		17			11
U.S. Total	307	317	321	157	329	346	334		4968	4515	4002	1813	3964	3919	3812		620	512	509	122	509	503	290			147		57			165
OtherArea																															
IL	679	675	688	594	700	738	582		62	48	68	48	70	73	49		11	11	12	16	12	13	16			40		64			69
IN	354	391	365	358	373	398	384		62	56	65	58	67	69	59		158	32	150	32	151	153	32			2		2			2
MI	518	652	516	562	520	541	549		49	49	52	50	53	54	51		71	29	68	29	68	68	28			111		114			120
OH	546	604	550	506	558	593	487		50	93	59	108	60	62	108		22	6	34	15	35	35	14			19		35			34
WI	458	315	467	290	474	506	293		32	37	34	37	34	35	37		9	17	9	13	10	10	13			11		12			12
5-State Total	2555	2637	2586	2310	2625	2776	2295		255	283	278	301	284	293	304		271	95	273	105	276	279	103			183		227			237
U.S. Total	17876	21093	18638	18683		20512	24300		3856	4899	4100	4220		4418	5357		2075	2947	2062	2559		2189	2709			2735		2621			2570
On-Road																															
IL	446	341	314	268	260	197	151		890	748	578	528	474	300	201			9		4			3			13		10			6
IN	405	282	237	235	193	150	138		703	541	425	402	313	187	173			11		3			2			9		7			2
MI	522	351	335	269	303	217	163		926	722	680	501	619	385	204			14		4			3			12		9			3
OH	574	680	365	424	340	238	242		1035	934	609	693	512	270	274			18		4			4			16		12			4
WI	238	175	144	119	117	88	68		481	457	303	322	226	118	138			9		2			2			8		6			2
5-State Total	2185	1829	1395	1315	1213	890	762		4035	3402	2595	2446	2144	1260	990			61		17			14			58		44			17
U.S. Total	14263				7825				23499				13170																		
EGU																															
IL	9	7	8	6	8	9	7		712	305	227	275	244	231	224		1310	1158	944	958	789	810	869			13		34			77
IN	6	6	6	6	7	6	6		830	393	406	370	424	283	255		2499	2614	1267	1033	1263	1048	1036			16		73			74
MI	12	6	11	4	11	12	4		448	393	218	242	219	247	243		1103	1251	1022	667	1031	1058	725			15		25			29
OH	5	4	6	5	7	7	6		1139	408	330	280	322	271	285		3131	3405	1463	1326	994	701	983			28		94			80
WI	3	5	3	2	4	4	3		293	213	146	165	139	147	177		602	545	512	460	492	500	435			0		22			25
5-State Total	35	28	34	23	37	38	26		3422	1712	1327	1332	1348	1179	1184		8645	8973	5208	4444	4569	4117	4048			72		248			285
U.S. Total	214	140	195	124	197	215	138		14371	10316	7746	7274	7721	7007	6095		31839	34545	20163	16903	17629	14727	14133			685		1131			1571
Non-EGU																															
IL	313	221	286	218	305	350	258		356	330	334	218	338	343	235		373	423	251	335	257	249	346			16		17			19
IN	150	130	160	137	170	199	167		238	179	212	175	216	225	178		292	218	270	216	274	290	180			35		36			44
MI	123	116	115	119	122	139	140		216	240	208	242	214	229	271		162	158	166	148	171	185	163			20		21			25
OH	77	84	75	87	79	90	104		177	175	157	166	160	167	178		240	289	231	288	210	216	293			27		28			33
WI	88	84	97	87	104	120	106		98	97	91	93	92	94	81		163	156	154	152	155	156	85			0		0.1			0.1
5-State Total	751	635	733	648	780	898	775		1085	1021	1002	894	1020	1058	943		1230	1244	1072	1139	1067	1096	1067			98		102			121
U.S. Total	4087	3877	4409		4700	5378			6446	6730	6129		6435	6952			5759	5630	6093		6340	6970						1444			1777
IL	1681	1576	1470	1353	1432	1434	1217		2621	2010	1671	1572	1545	1287	1029		1725	1656	1212	1337	1059	1072	1251			119		155			189
IN	1045	1009	867	901	843	853	826		2134	1453	1339	1250	1248	989	819		2966	2902	1690	1294	1691	1492	1256			81		133			131
MI	1530	1546	1291	1311	1239	1139	1134		1958	1730	1429	1314	1349	1118	946		1356	1495	1260	865	1271	1312	927			183		190			190
OH	1432	1735	1165	1323	1137	1062	1082		2831	2048	1478	1619	1342	1001	1074		3416	3761	1732	1650	1240	953	1304			121		195			166
WI	1005	821	909	705	878	862	630		1128	1019	747	800	647	520	551		800	750	687	635	667	675	540			35		54			47
5-State Total	6693	6687	5702	5593	5529	5350	4889		10672	8260	6664	6555	6131	4915	4419		10263	10564	6581	5781	5928	5504	5280			539		727			723

Table 6b. EGU Emissions for Midwest States (2018)						
	Heat Input (MMBTU/year)	**Scenario**	**SO2 (tons/year)**	**SO2 (lb/MMBTU)**	**NOx (tons/year)**	**NOx (lb/MMBTU)**
IL	**980,197,198**	**2001 - 2003 (average)**	**362,417**	**0.74**	**173,296**	**0.35**
		IPM 2.1.9	241,000		73,000	
	1,310,188,544	IPM3.0 (base)	277,337	0.423	70,378	0.107
		IPM3.0 - will do	140,296	0.214	62,990	0.096
		IPM3.0 - may do	140,296	0.214	62,990	0.096
IN	**1,266,957,401**	**2001 - 2003 (average)**	**793,067**	**1.25**	**285,848**	**0.45**
		IPM 2.1.9	377,000		95,000	
	1,509,616,931	IPM3.0 (base)	361,835	0.479	90,913	0.120
		IPM3.0 - will do	417,000	0.552	94,000	0.125
		IPM3.0 - may do	417,000	0.552	94,000	0.125
MI	**756,148,700**	**2001 - 2003 (average)**	**346,959**	**0.92**	**132,995**	**0.35**
		IPM 2.1.9	399,000		100,000	
	1,009,140,047	IPM3.0 (base)	244,151	0.484	79,962	0.158
		IPM3.0 - will do	244,151	0.484	79,962	0.158
		IPM3.0 - may do	244,151	0.484	79,962	0.158
OH	**1,306,296,589**	**2001 - 2003 (average)**	**1,144,484**	**1.75**	**353,255**	**0.54**
		IPM 2.1.9	216,000		84,000	
	1,628,081,545	IPM3.0 (base)	316,883	0.389	96,103	0.118
		IPM3.0 - will do	348,000		101,000	
		IPM3.0 - may do	348,000		101,000	
WI	**495,475,007**	**2001 - 2003 (average)**	**191,137**	**0.77**	**90,703**	**0.36**
		IPM 2.1.9	155,000		46,000	
	675,863,447	IPM3.0 (base)	127,930	0.379	56,526	0.167
		IPM3.0 - will do	150,340	0.445	55,019	0.163
		IPM3.0 - may do	62,439	0.185	46,154	0.137
IA	**390,791,671**	**2001 - 2003 (average)**	**131,080**	**0.67**	**77,935**	**0.40**
		IPM 2.1.9	147,000		51,000	
	534,824,314	IPM3.0 (base)	115,938	0.434	59,994	0.224
		IPM3.0 - will do	115,938	0.434	59,994	0.224
		IPM3.0 - may do	100,762	0.377	58,748	0.220
MN	**401,344,495**	**2001 - 2003 (average)**	**101,605**	**0.50**	**85,955**	**0.42**
		IPM 2.1.9	86,000		42,000	
	447,645,758	IPM3.0 (base)	61,739	0.276	41,550	0.186
		IPM3.0 - will do	54,315	0.243	49,488	0.221
		IPM3.0 - may do	51,290	0.229	39,085	0.175
MO	**759,902,542**	**2001 - 2003 (average)**	**241,375**	**0.63**	**143,116**	**0.37**
		IPM 2.1.9	281,000		78,000	
	893,454,905	IPM3.0 (base)	243,684	0.545	72,950	0.163
		IPM3.0 - will do	237,600	0.532	72,950	0.163
		IPM3.0 - may do	237,600	0.532	72,950	0.163
ND	**339,952,821**	**2001 - 2003 (average)**	**145,096**	**0.85**	**76,788**	**0.45**
		IPM 2.1.9	109,000		72,000	
	342,685,501	IPM3.0 (base)	41,149	0.240	44,164	0.258
		IPM3.0 - will do	56,175	0.328	58,850	0.343
		IPM3.0 - may do	56,175	0.328	58,850	0.343
SD	**39,768,357**	**2001 - 2003 (average)**	**12,545**	**0.63**	**15,852**	**0.80**
		IPM 2.1.9	12,000		15,000	
	44,856,223	IPM3.0 (base)	4,464	0.199	2,548	0.114
		IPM3.0 - will do	4,464	0.199	2,548	0.114
		IPM3.0 - may do	4,464	0.199	2,548	0.114

On-road Sources: For 2002, EMS was run by LADCO using VMT and MOBILE6 inputs supplied by the LADCO States. EMS was run to generate 36 days (weekday, Saturday, Sunday for each month) at 36 km, and 9 days (weekday, Saturday, Sunday for June – August) at 12 km. For 2005, CONCEPT was run by a contractor (Environ) using transportation data (e.g., VMT and vehicle speeds) supplied by the state and local planning agencies in the LADCO States and Minnesota for 24 networks. These data were first processed with T3 (Travel Demand Modeling [TDM] Transformation Tool) to provide input files for CONCEPT to calculate link-specific, hourly emission estimates (Environ, 2008). CONCEPT was run with meteorological data for a July and January weekday, Saturday, and Sunday (July 15 – 17 and January 16 – 18). A spatial plot of emissions is provided in Figure 43.

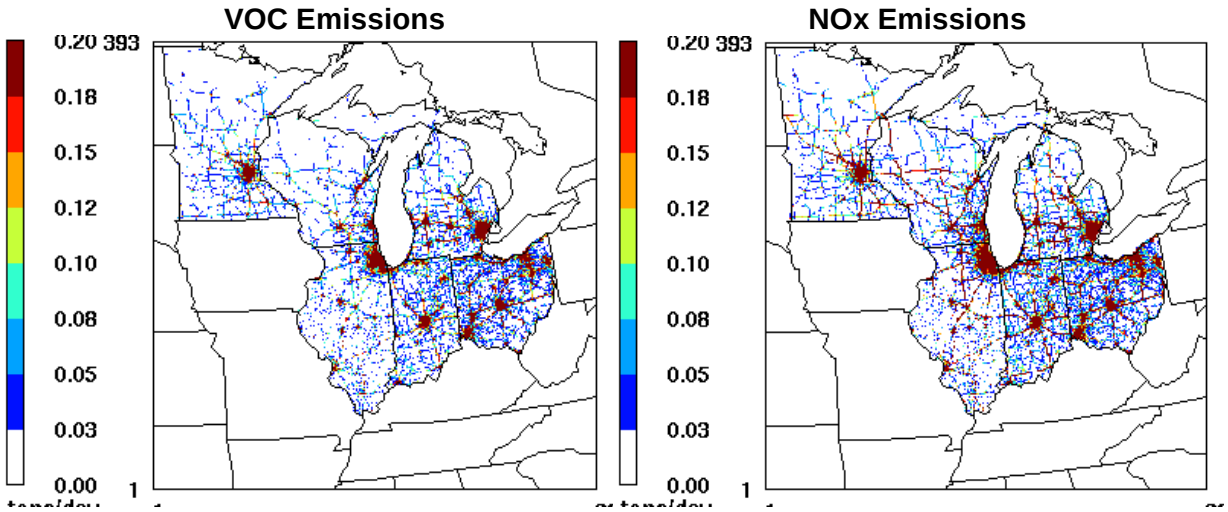


Figure 43. Motor vehicle emissions for VOC (left) and NOx (right) for a July weekday (2005)

Off-road Sources: For 2002 and 2005, NMIM and NMIM2005, respectively, were run by Wisconsin DNR. Additional off-road sectors (i.e., commercial marine, aircraft, and railroads [MAR]) were handled separately. Local data for agricultural equipment, construction equipment, commercial marine, recreational marine, and railroads were prepared by contractors (Environ, 2004, and E.H. Pechan, 2004). For Base M, updated local data for railroads and commercial marine were prepared by a contractor (Environ, 2007b, 2007c). Table 7 compares the Base M 2005 and Base K 2002 emissions. Compared to 2002, the new 2005 emissions reflect substantially lower commercial marine emissions and lower locomotive NOx emissions.

Table 7. Locomotive and commercial marine emissions for the five LADCO States (2002 v. 2005)

	Railroads (TPY)			Commercial Marine (TPY)	
	2002	**2005**		**2002**	**2005**
VOC	7,890	7,625		1,562	828
CO	20,121	20,017		8,823	6,727
NOx	182,226	145,132		64,441	42,336
PM	5,049	4,845		3,113	1,413
SO2	12,274	12,173		25,929	8,637
NH3	86	85		----	----

Area Sources: For 2002 and 2005, EMS was run by LADCO using data supplied by the LADCO States to produce weekday, Saturday, and Sunday emissions for each month. For 2005, special attention was given to two source categories: industrial adhesive and sealant solvents (which were dropped from the inventory to avoid double-counting) and outdoor wood boilers (which were added to the inventory).

Point Sources: For 2002 and 2005, EMS was run by LADCO using data supplied by the LADCO States to produce weekday, Saturday, and Sunday emissions for each month. For EGUs, the annual and summer season emissions were temporalized for modeling purposes using profiles prepared by Scott Edick (Michigan DEQ) based on CEM data.

Biogenics: For Base M, a contractor (Alpine) provided an updated version of the CONCEPT/MEGAN biogenics model. Compared to the previous (EMS/BIOME) emissions, there is more regional isoprene using MEGAN compared to the BIOME estimates used for Base K (see Figure 44). Also, with the secondary organic aerosol updates to the CAMx air quality model, Base M includes emissions for monoterpenes and sesquiterpenes, which are pre-cursors of secondary $PM_{2.5}$ organic carbon mass.

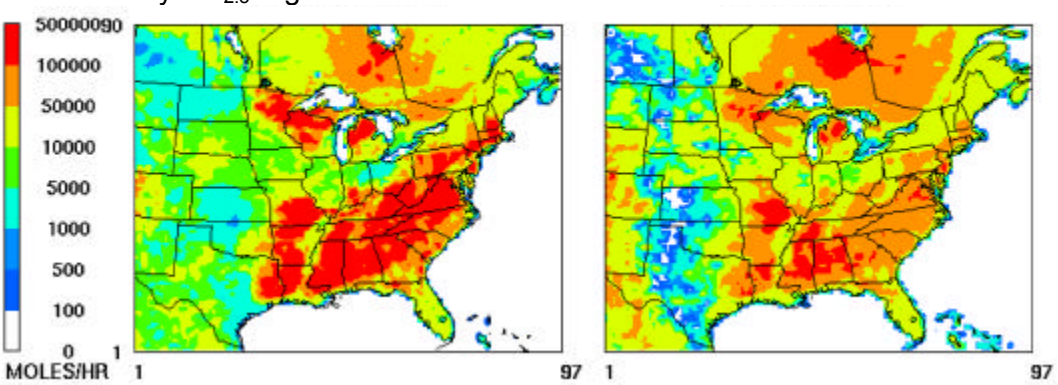


Figure 44. Isoprene emissions for Base M (left) v. Base K (right)

Ammonia: For Base M, the CMU-based 2002 (Base K) ammonia emissions were projected to 2005 using growth factors from the Round 4 emissions modeling. These emissions were then adjusted by applying temporal factors by month based on the process-based ammonia emissions model (Zhang, et al, 2005, and Mansell, et al, 2005). A plot of average daily emissions by state and month is provided in Figure 45. A spatial plot of emissions is provided in Figure 46, which shows high emissions densities in the central U.S.

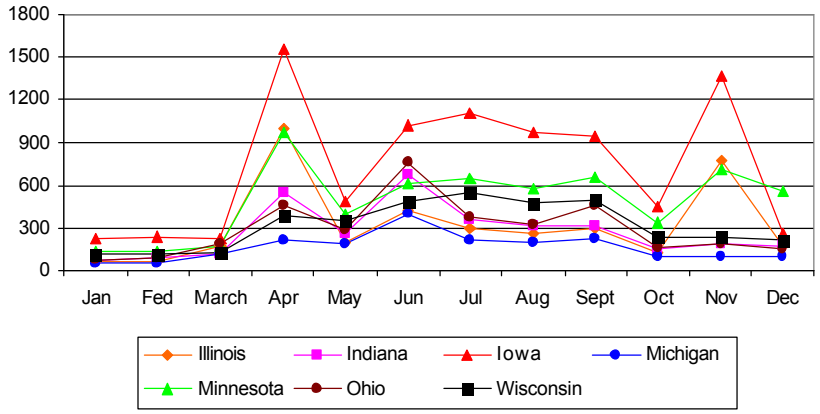


Figure 45. Average daily ammonia emissions for Midwest States by month (2005) - (units: average daily emissions – tons per day)

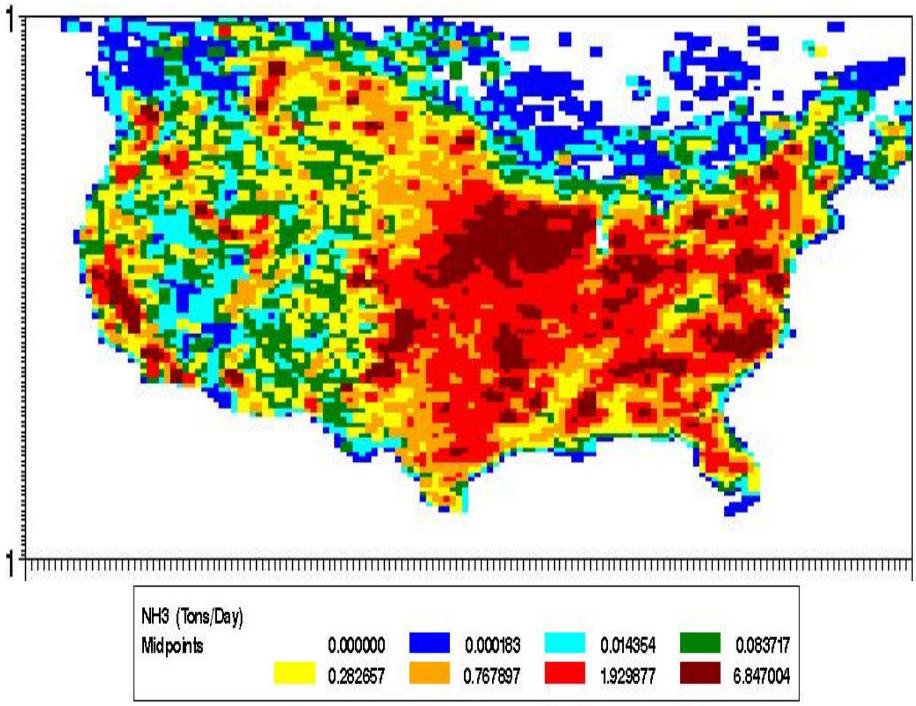


Figure 46. Ammonia emissions for a July weekday (2005) – 12 km modeling domain

Canadian Emissions: For Base M, Scott Edick (Michigan DEQ) processed the 2005 Canadian National Pollutant Release Inventory, Version 1.0 (NPRI). Specifically, a subset of the NPRI data (emissions and stack parameters) relevant to the air quality modeling were reformatted. The resulting emissions represent a significant improvement in the base year emissions.

A spatial plot of point source SO2 and NOx emissions is provided in Figure 47. Additional plots and emission reports are available on the LADCO website (http://www.ladco.org/tech/emis/basem/canada/index.htm).

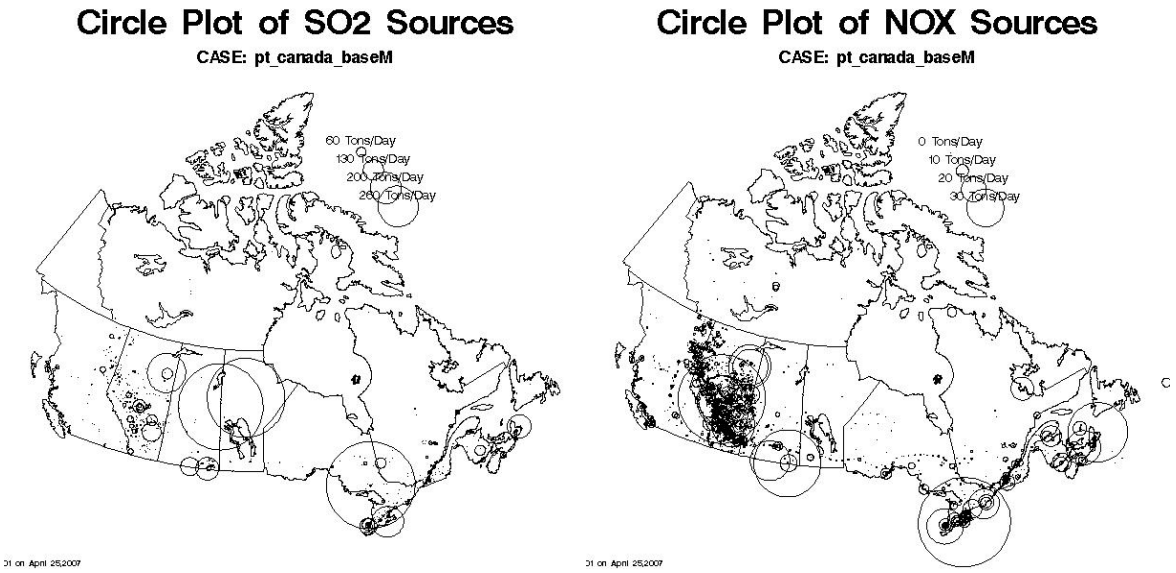


Figure 47. Canadian point source emissions for SO2 (left) and NOx (right)

Fires: For Base K, a contractor (EC/R, 2004) developed a 2001, 2002, and 2003 fire emissions inventory for eight Midwest States (five LADCO states plus Iowa, Minnesota, and Missouri), including emissions from wild fires, prescribed fires, and agricultural burns. Projected emissions were also developed for 2010 and 2018 assuming "no smoke management" and "optimal smoke management" scenarios. An early model sensitivity run showed very little difference in modeled $PM_{2.5}$ concentrations. Consequently, the fire emissions were not included in subsequent modeling runs (i.e., they were not in the Base K or Base M modeling inventories).

Future Year Emissions: Complete emission inventories were developed for several future years: Base K – 2009, 2012, and 2018, and Base M – 2009 and 2018. In addition, 2008 (Base K and Base M) and 2012 (Base M) proxy inventories were estimated based on the 2009 and 2018 data. (Note, the EGU emissions for the Base M 2012 inventory were based on EPA's IPM3.0 modeling.)

Source sector emission summaries for the base years and future years are shown in Figure 48. Additional detail is provided in Tables 6a and 6b.

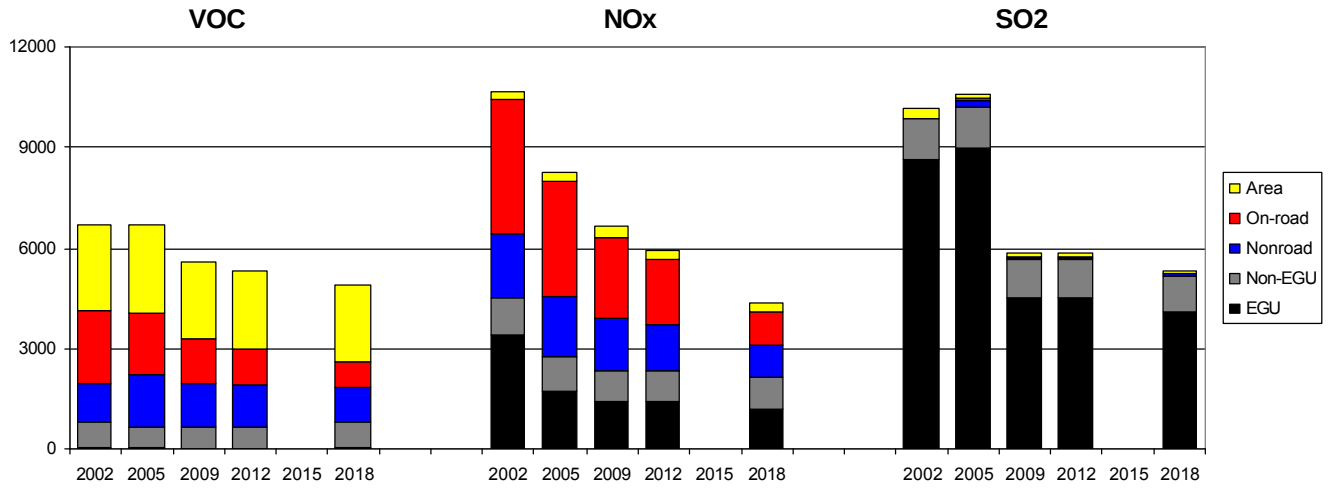


Figure 48. Base year and future year emissions for 5-State LADCO Region (TPD, July weekday)

For on-road, and nonroad, the future year emissions were estimated by models (i.e., EMS/CONCEPT and NMIM, respectively). One adjustment was made to the 2009 and 2018 motor vehicle emission files prepared by Environ with CONCEPT. To reflect newer transportation modeling conducted by CATS for the Chicago area, emissions were increased by 9% in 2009 and 2018. The 2005 base year and adjusted 2009 and 2018 motor vehicle emissions are provided in Table 8.

Table 8. Motor Vehicle Emissions Produced by CONCEPT Modeling (July weekday – tons per day)

Year	State	Sum of CO	Sum of TOG	Sum of NOx	Sum of PM2.5	Sum of SO2	Sum of NH3	Sum of VMT
2005	IL	3,684.3	341.5	748.2	12.9	9.6	35.9	344,087,819.6
	IN	3,384.9	282.0	541.1	8.9	11.1	25.7	245,537,231.9
	MI	4,210.3	351.9	722.0	12.4	13.9	35.3	340,834,025.9
	MN	2,569.1	218.7	380.5	6.3	7.6	17.7	170,024,599.7
	OH	6,113.4	679.8	933.6	16.2	18.8	36.5	360,521,068.6
	WI	2,206.0	175.1	457.5	7.8	9.2	19.7	189,123,964.3
Total		22,168.0	2,049.0	3,782.9	64.5	70.2	170.8	1,650,128,709.9
2009	IL	2,824.4	268.0	527.8	10.1	4.2	38.9	372,132,591.1
	IN	2,839.5	234.9	401.9	6.7	2.8	26.1	249,817,026.3
	MI	3,172.0	269.2	500.9	9.2	4.0	37.1	356,347,010.5
	MN	2,256.8	206.3	307.5	5.1	2.3	21.5	204,443,017.8
	OH	4,619.2	423.7	693.5	11.8	4.7	39.5	387,428,127.2
	WI	1,673.4	119.4	322.1	5.7	2.3	20.6	197,729,964.9
Total		17,385.3	1,521.5	2,753.6	48.7	20.3	183.6	1,767,897,737.8
2018	IL	2,084.7	151.5	200.7	6.3	3.7	43.1	413,887,887.3
	IN	2,217.3	138.4	173.0	4.4	2.6	30.2	288,042,232.1
	MI	2,434.3	163.5	204.1	5.9	3.6	40.5	388,128,431.8
	MN	1,799.6	123.1	137.1	3.6	2.2	24.9	237,022,213.7
	OH	3,361.5	242.5	274.1	6.8	4.0	43.1	421,694,093.4
	WI	1,255.5	68.4	138.5	3.9	2.0	22.2	218,277,167.5
Total		13,152.9	887.5	1,127.5	30.8	18.1	203.9	1,967,052,025.8

For EGUs, future year emissions were based on IPM2.1.9 modeling completed by the RPOs in July 2005 Base K and IPM3.0 completed by EPA in February 2007 for Base M. Several CAIR scenarios were assumed:

Base K
1a: IPM2.1.9, with full trading and banking
1b: IPM2.1.9, with restricted trading (compliance with state-specific emission budgets) and full trading
1d: IPM2.1.9, with restricted trading (compliance with state-specific emission budgets)

Base M
5a: EPA's IPM3.0 was assumed as the future year base for EGUs.
5b: EPA's IPM3.0, with several "will do" adjustments identified by the States. These adjustments should reflect a legally binding commitment (e.g., signed contract, consent decree, or operating permit).
5c: EPA's IPM3.0, with several "may do" adjustments identified by the States. These adjustments reflect less rigorous criteria, but should still be some type of public reality (e.g., BART determination or press announcement).

For other sectors (area, MAR, and non-EGU point sources), the future year emissions for the LADCO States were derived by applying growth and control factors to the base year inventory. These factors were developed by a contractor (E.H. Pechan, 2005 and E.H. Pechan, 2007). For the non-LADCO States, future year emission files were based on data from other RPOs.

Growth factors were based initially on EGAS (version 5.0), and were subsequently modified (for select, priority categories) by examining emissions activity data. Due to a lack of information on future year conditions, the biogenic VOC and NOx emissions, and all Canadian emissions were assumed to remain the constant between the base year and future years.

A "base" control scenario was prepared for each future year based on the following "on the books" controls:

On-Highway Mobile Sources
- Federal Motor Vehicle Emission Control Program, low-sulfur gasoline and ultra-low sulfur diesel fuel
- Inspection - maintenance programs, including IL's vehicle emissions tests (NE IL), IN's vehicle emissions testing program (NW IN), OH's E-check program (NE OH), and WI's vehicle inspection program (SE WI) – note: a special emissions modeling run was done for the Cincinnati/Dayton area to reflect the removal of the state's E-check program and inclusion of low RVP gasoline
- Reformulated gasoline, including in Chicago-Gary,-Lake County, IL,IN; and Milwaukee, Racine, WI

Off-Highway Mobile Sources
- Federal control programs incorporated into NONROAD model (e.g., nonroad diesel rule), plus the evaporative Large Spark Ignition and Recreational Vehicle standards
- Heavy-duty diesel (2007) engine standard/Low sulfur fuel
- Federal railroad/locomotive standards
- Federal commercial marine vessel engine standards

Area Sources (Base M only)
- Consumer solvents
- AIM coatings
- Aerosol coatings
- Portable fuel containers

Power Plants
- Title IV (Phases I and II)
- NOx SIP Call
- Clean Air Interstate Rule

Other Point Sources

- VOC 2-, 4-, 7-, and 10-year MACT standards
- Combustion turbine MACT

Other controls included in the modeling include: consent decrees (refineries, ethanol plants, and ALCOA)[9], NOx RACT in Illinois and Ohio[10], and BART for a few non-EGU sources in Indiana and Wisconsin.

For Base K, several additional control scenarios were considered:

Scenario 2 – "base" controls plus additional controls recommended in LADCO White Papers for stationary and mobile sources

Scenario 3 – Scenario 2 plus additional White Papers for stationary and mobile sources

Scenario 4 – "base" controls plus additional candidate control measures under discussion by State Commissioners

Scenario 5 – "base" controls plus additional candidate control measures identified by the LADCO Project Team

3.7 Basecase Modeling Results

The purpose of the basecase modeling is to evaluate model performance (i.e., assess the model's ability to reproduce the observed concentrations). The model performance evaluation focused on the magnitude, spatial pattern, and temporal of modeled and measured concentrations. This exercise was intended to assess whether, and to what degree, confidence in the model is warranted (and to assess whether model improvements are necessary).

Model performance was assessed by comparing modeled and monitored concentrations. Graphical (e.g., side-by-side spatial plots, time series plots, and scatter plots) and statistical analyses were conducted. No rigid acceptance/rejection criteria were used for this study. Instead, the statistical guidelines recommended by EPA and other modeling studies (e.g., modeling by the other RPOs) were used to assess the reasonableness of the results. The model performance results presented here describe how well the model replicates observed ozone and $PM_{2.5}$ concentrations after a series of iterative improvements to model inputs.

Ozone: Spatial plots are provided for high ozone periods in June 2002 and June 2005 (see Figures 49a and 49b). The plots show that the model is doing a reasonable job of reproducing the magnitude, day-to-day variation, and spatial pattern of ozone concentrations. There is a tendency, however, to underestimate the magnitude of regional ozone levels. This is more apparent with the 2002 modeling; the regional concentrations in the 2005 modeling agree better with observations due to model and inventory improvements.

[9] E.H. Pechan's original control file included control factors for three sources in Wayne County, MI. These control factors were not applied in the regional-scale modeling to avoid double-counting with the State's local-scale analysis for PM2.5

[10] NOx RACT in Wisconsin is included in the 2005 basecase (and EGU "will do" scenario). NOx RACT in Indiana was not included in the modeling inventory.

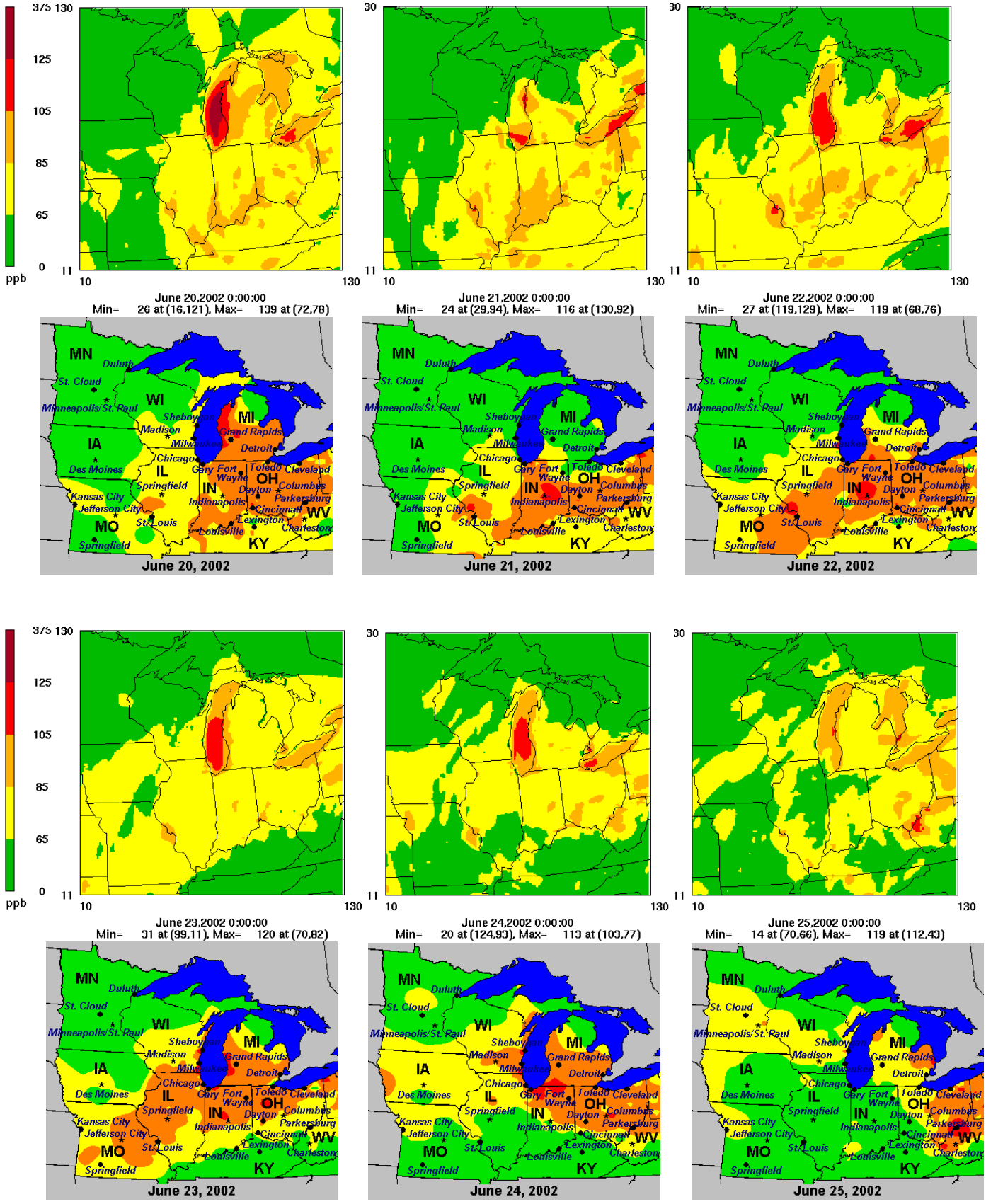


Figure 49a. Modeled (top) v. monitored (bottom) 8-hour ozone concentrations: June 20 – 25, 2002

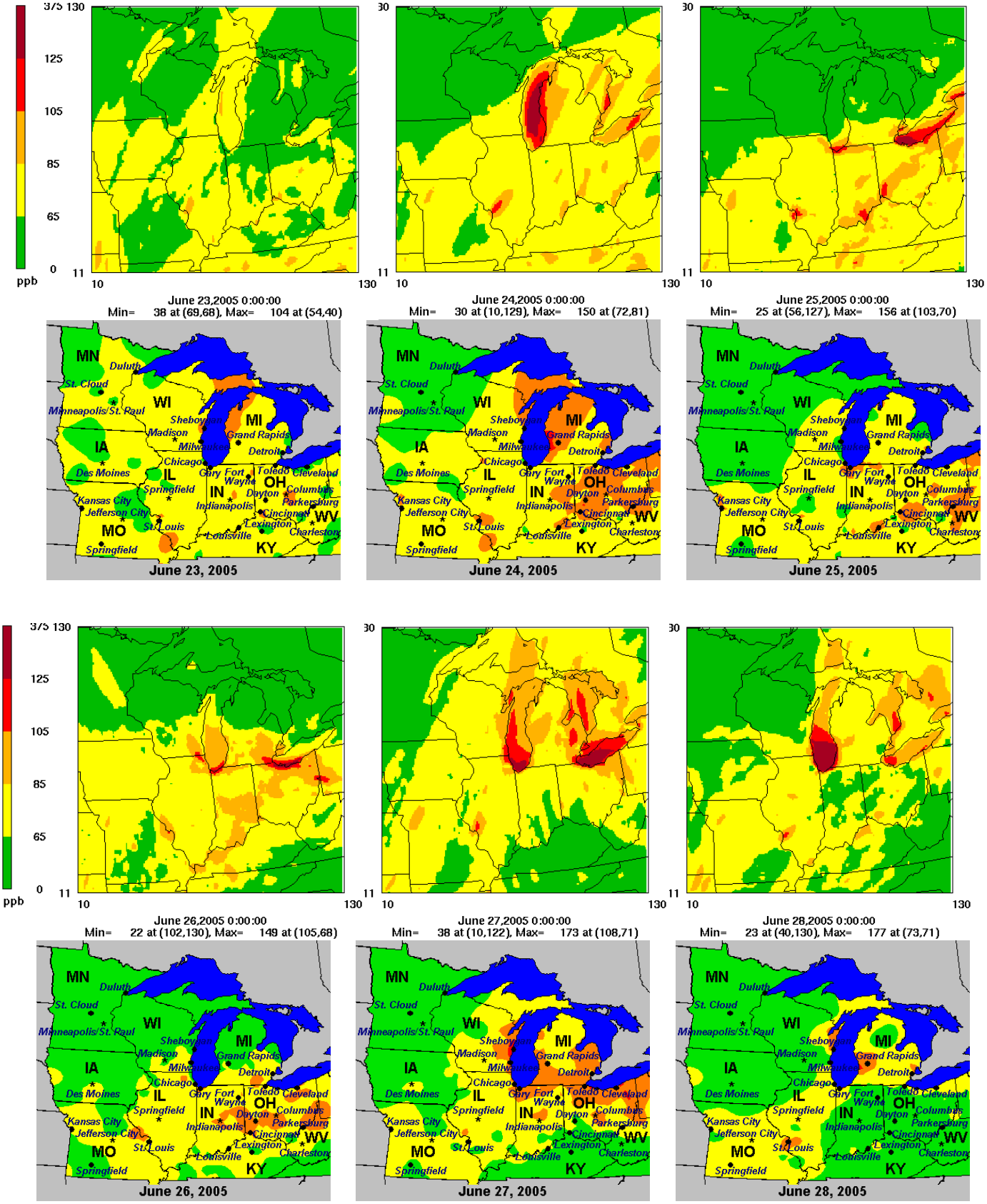


Figure 49b Modeled (top) v. monitored (bottom) 8-hour ozone concentrations: June 23– 28 2005

Standard model performance statistics were generated for the entire 12 km domain, and by day and by monitoring site. The domain-wide mean normalized bias for the 2005 base year is similar to that for the 2002 base year and is generally within 30% (see Figure 50).

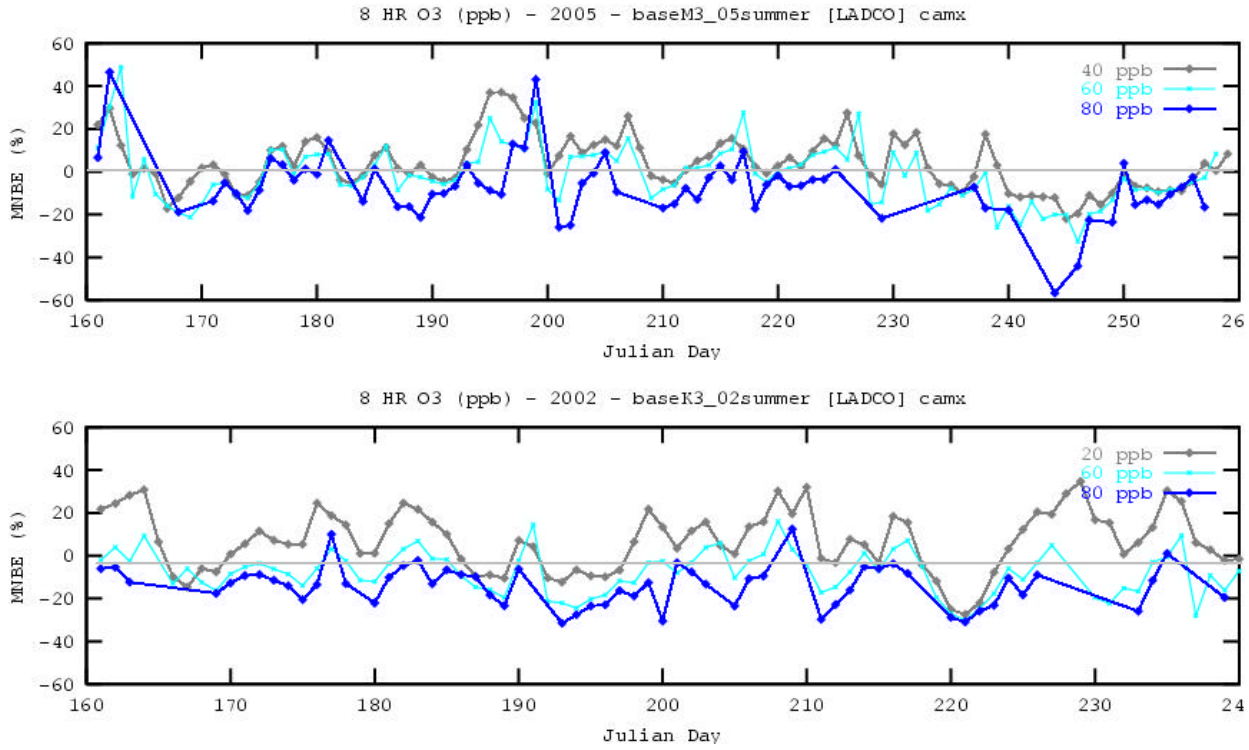


Figure 50. Mean bias for summer 2005 (Base M) and summer 2002 (Base K)

Station-average metrics (over the entire summer) are shown in Figure 51. The bias results further demonstrate the model's tendency to underestimate absolute ozone concentrations.

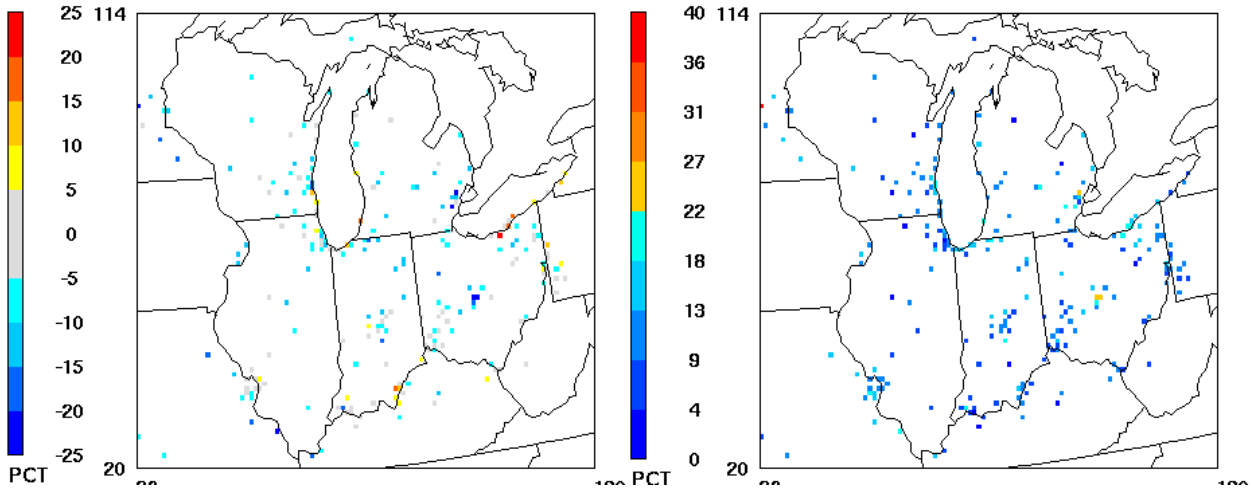


Figure 51. Mean bias (left) and gross error (right) for summer 2005

A limited 4 km ozone analysis was performed by LADCO to address the effect of grid spacing. For this modeling, 4 km grids were placed over Lake Michigan and the Detroit-Cleveland area (see Figure 52). Model inputs included 4 km emissions developed by LADCO (consistent with Base K/Round 4) and the 4 km meteorology developed by Alpine Geophysics.

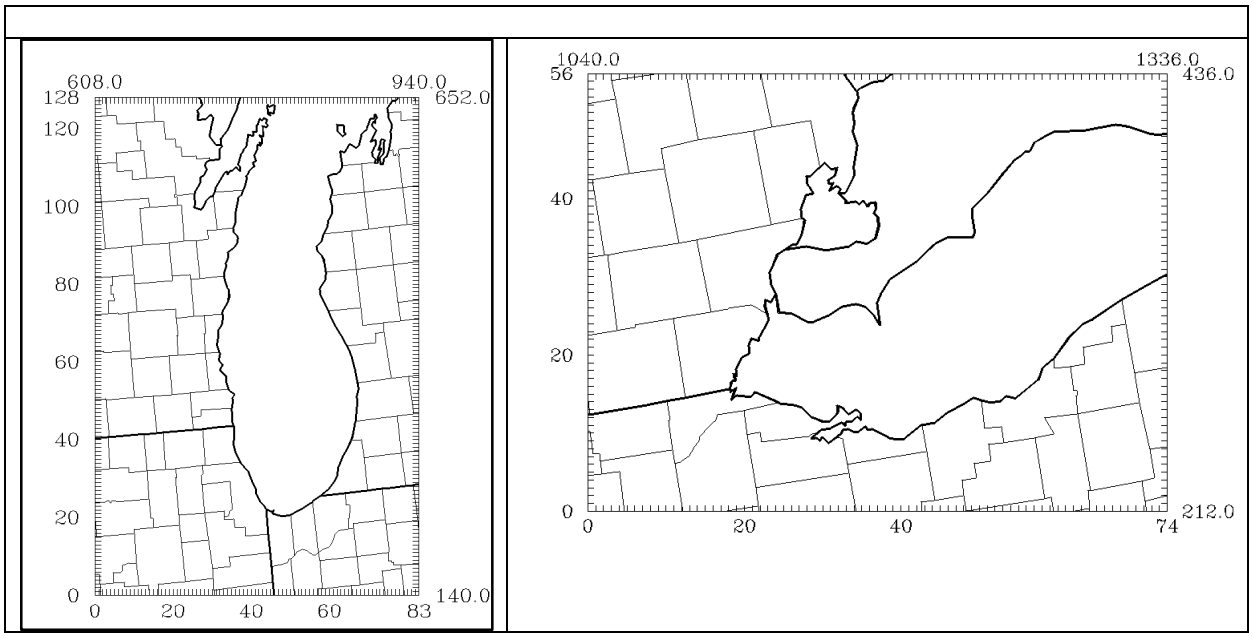


Figure 52. 4 km grids for Lake Michigan region and Detroit-Cleveland region

Hourly time series plots were prepared for several monitors (see Figure 53). The results are similar at 12 km and 4 km, with some site-by-site and day-by-day differences.

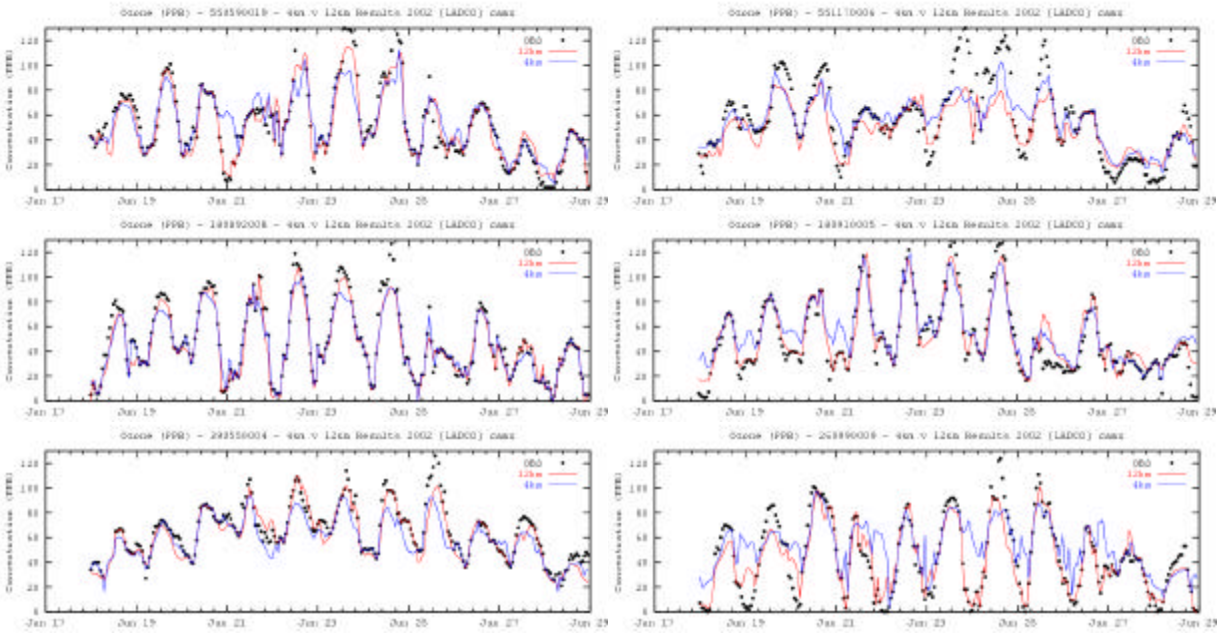
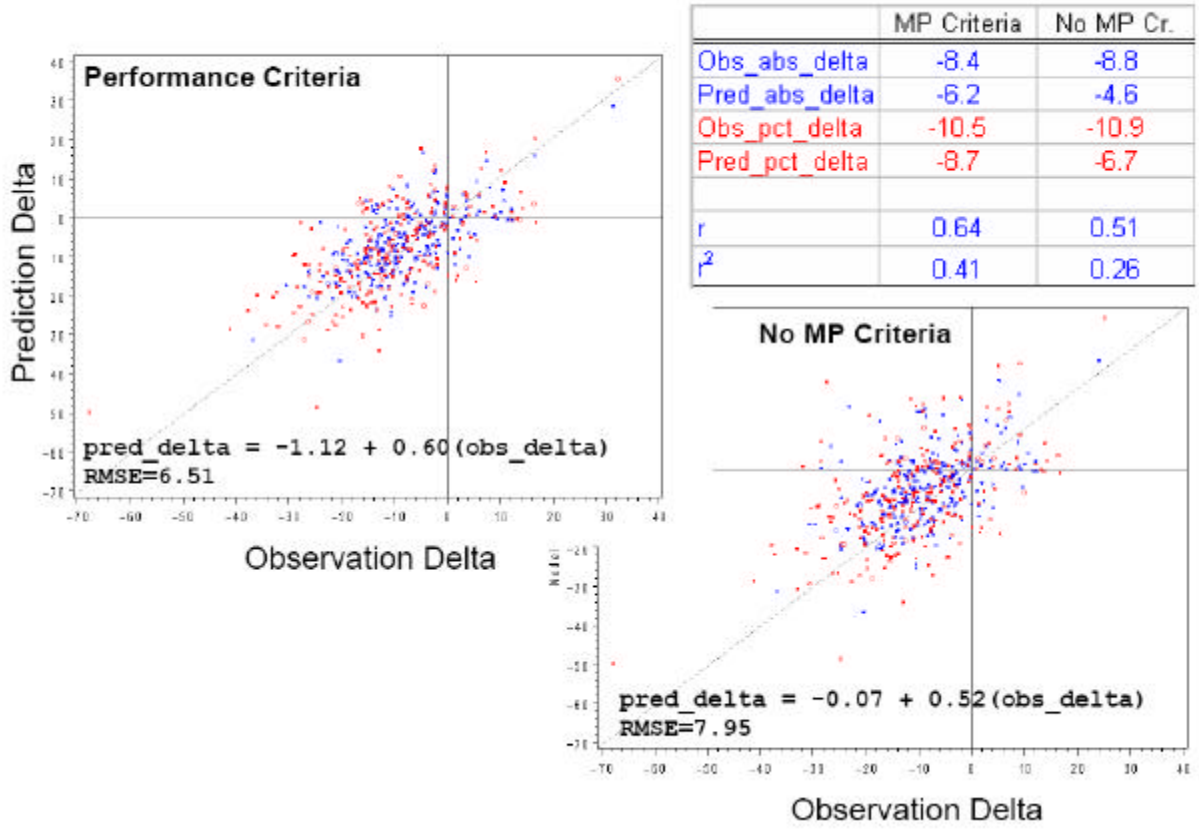


Figure 53. Ozone time series plots for 12 km and 4 km modeling (June 17-29, 2002)

An additional diagnostic analysis was performed to assess the response of the modeling system to changes in emissions (Baker and Kenski, 2007). Specifically, the 2002-to-2005 change in observed ozone concentrations was compared to the change in modeled ozone concentrations based on the 95th percentile(and above) concentration values for each monitor. This analysis was also done with the inclusion of model performance criteria which eliminated poorly performing days (i.e., error > 35%). The results show good agreement in the modeled and monitored ozone concentration changes (e.g., ozone improves by about 9-10 ppb between 2002 and 2005 according to the model and the measurements) – see Figure 54. This provides further support for using the model to develop ozone control strategies.



	MP Criteria	No MP Cr.
Obs_abs_delta	-8.4	-8.8
Pred_abs_delta	-6.2	-4.6
Obs_pct_delta	-10.5	-10.9
Pred_pct_delta	-8.7	-6.7
r	0.64	0.51
r^2	0.41	0.26

Figure 54. Comparison of change in predicted and observed ozone concentrations (2002 v. 2005)

$PM_{2.5}$: Time series plots of the monthly average mean bias and annual fractional bias for Base M and Base K are shown in Figure 55. As can be seen, Base M model performance for most species is fair (i.e., close to "no bias" throughout most of the year), with two main exceptions. First, the Base M and Base K results for organic carbon are poor, suggesting the need for more work on primary organic carbon emissions. Second, the Base M results for sulfate, while acceptable (i.e., bias values are within 35%), are not as good as the Base K results (e.g., noticeable underprediction during the summer months).

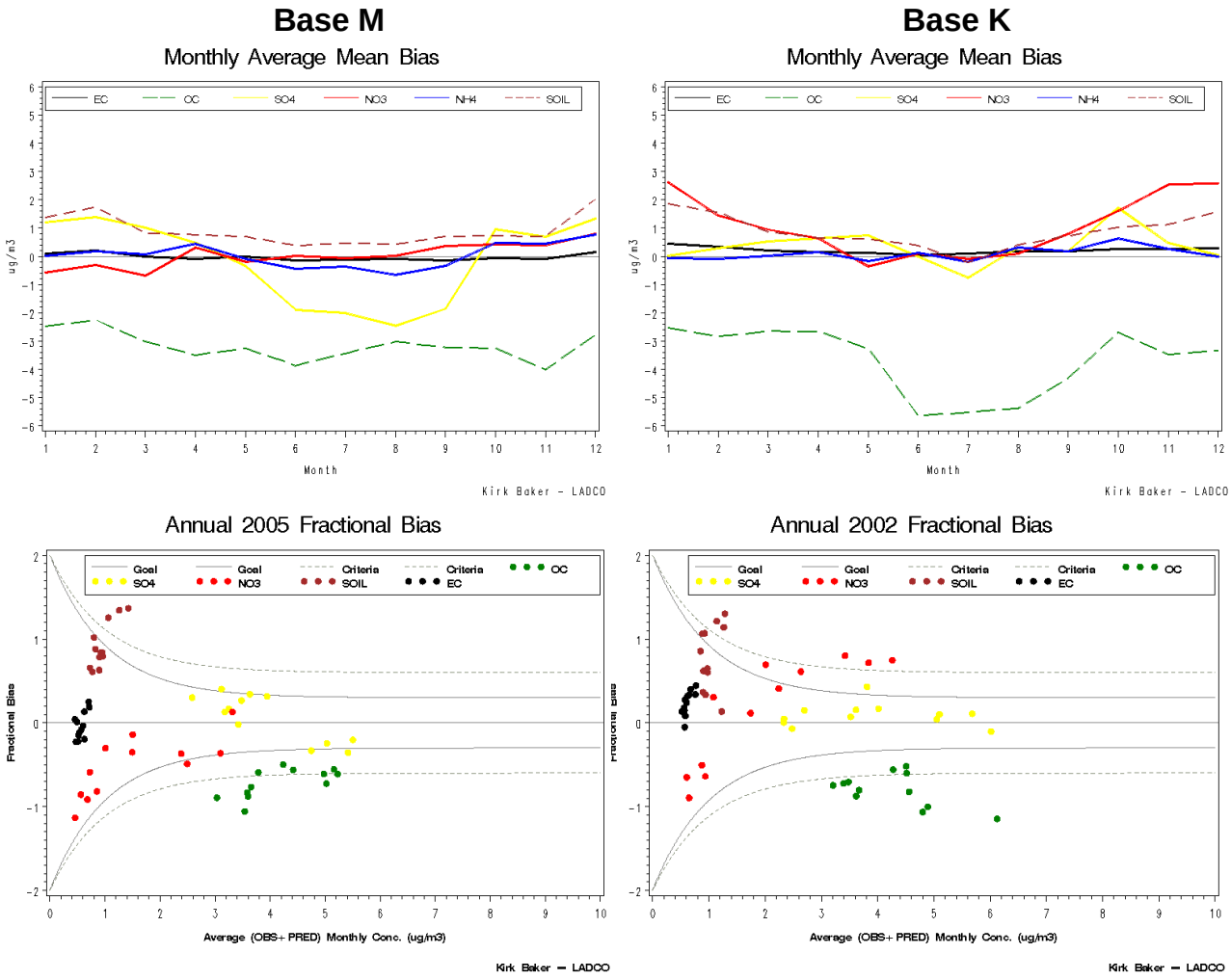


Figure 55. $PM_{2.5}$ Model performance - monthly average mean bias and annual fractional bias for Base M (left column) and Base K (right column)

Two analyses were undertaken to understand sulfate model performance for 2005:

- Assess Meteorological Influences: The MM5 model performance evaluation showed that rainfall is over-predicted by MM5 over most of the domain during the summer months (LADCO, 2007c). Because CAMx does not explicitly use the rainfall output by MM5, this may or may not result in over-prediction sulfate wet deposition (and under-prediction of sulfate concentrations). A sensitivity run was performed with no wet deposition for July, August, and September. The resulting model performance (see green line in Figure 56) showed a noticeable difference from the basecase (i.e., higher sulfate concentrations), and suggests that further evaluation of MM5 precipitation fields may be warranted.

- Assess Emissions Influences: The major contributor to sulfate concentrations in the region is SO2 emitted from EGUs. The basecase modeling inventory for EGUs is based on annual emissions, which were allocated to a typical weekday, Saturday, and Sunday by month using CEM-based temporal profiles. A sensitivity run was performed using day-specific emissions. The resulting model performance (see purple line in Figure 56) showed little difference from the basecase.

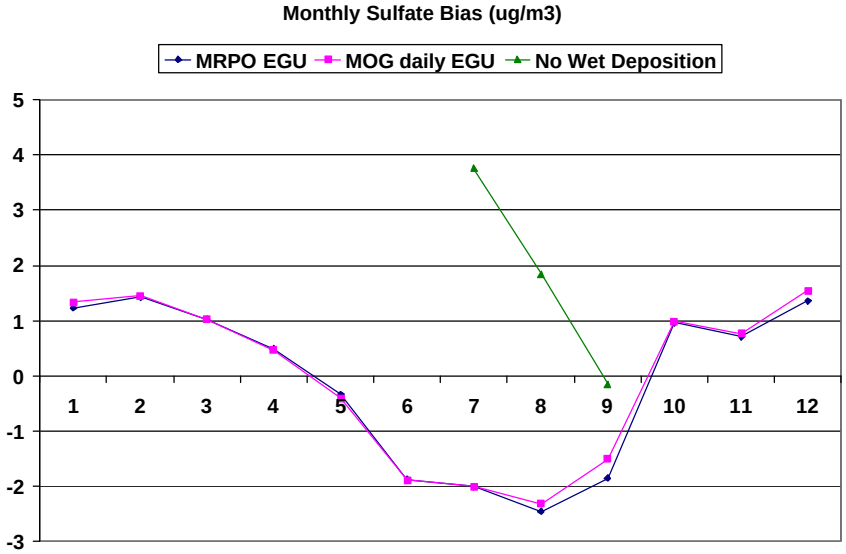


Figure 56. Monthly sulfate bias for Base M (MRPO EGU) v. two sensitivity analyses (Note: positive values indicate over-prediction, negative values indicate under-prediction)

To assess the effect of the wet deposition issue on future year modeled values, another sensitivity run was conducted with no wet deposition in Quarters 2-3 for the base year (2005) and 2018. The resulting future year values were only slightly different from the current base strategy run. In general, the future year values (without wet deposition) were a little higher (+0.15 ug/m^3 or less) in the Ohio Valley and a little lower (-.10 ug/m^3 of less) in the Great Lakes region. This sensitivity run provides a bound for sulfate wet deposition issue in terms of the attainment test, given that having no wet deposition is unrealistic. The results suggest that even with an improved wet deposition treatment, the Base M strategy results are not expected to change very much.

Time series plots of daily sulfate, nitrate, elemental carbon, and organic carbon concentrations for three Midwestern locations are presented in Figures 57 (2002) and 58 (2005). These results are consistent with the model performance statistics (i.e., good agreement for sulfates and nitrates and poor agreement [large underprediction] for organic carbon).

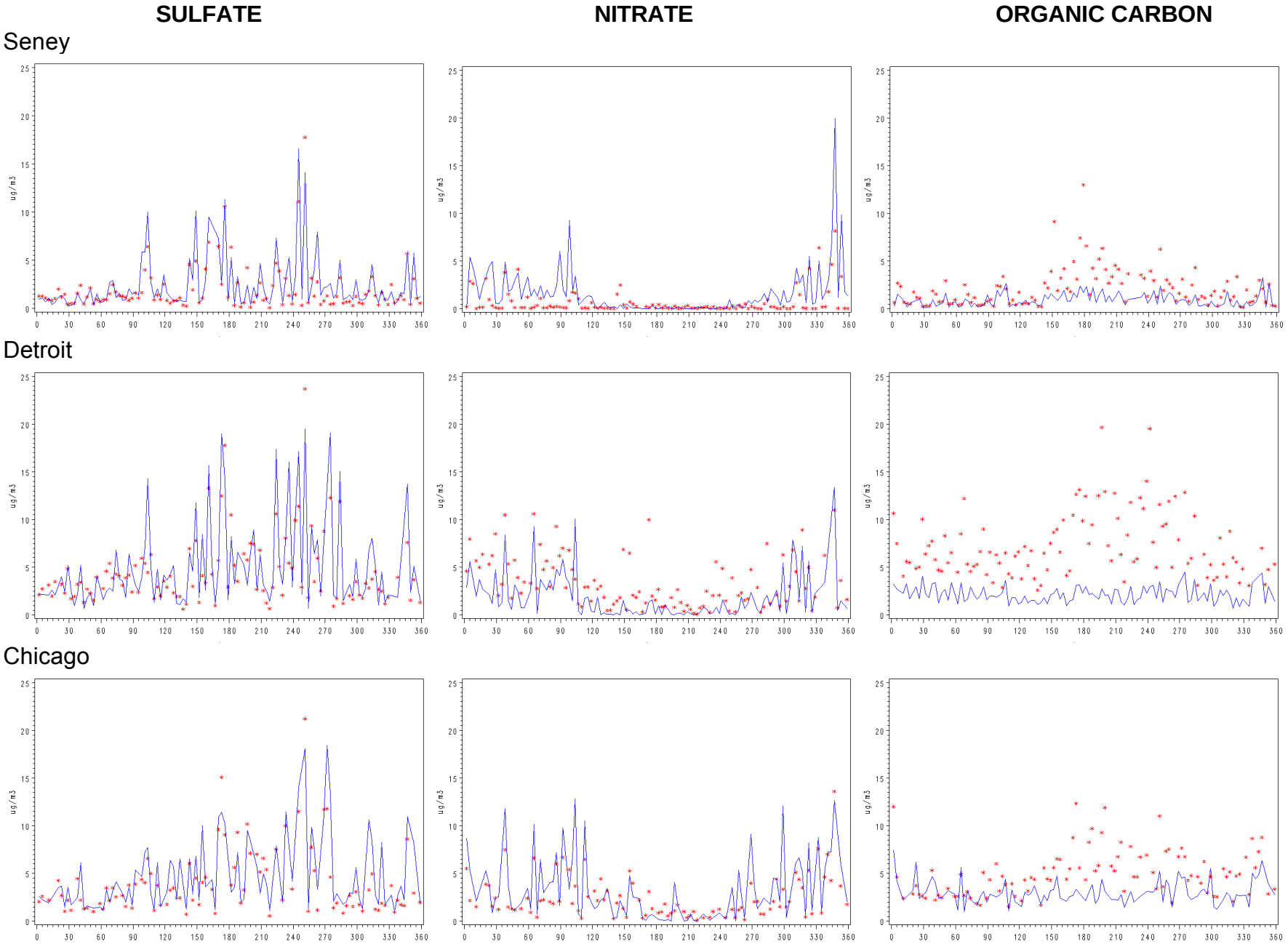
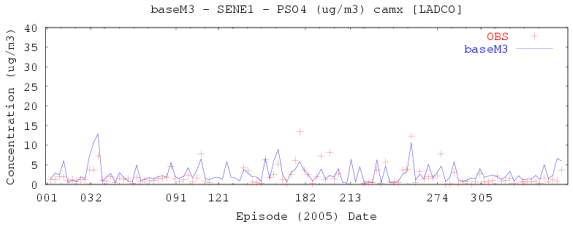
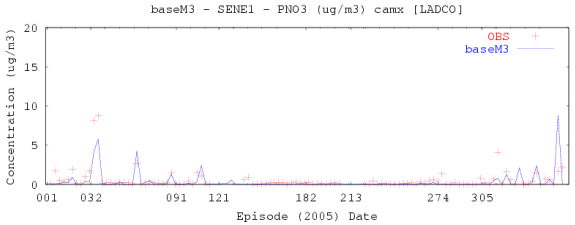


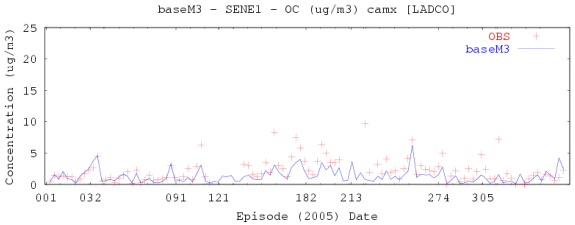
Figure 57. Time series of sulfate, nitrate, and organic carbon at three Midwest sites for 2005

SULFATE	NITRATE	ORGANIC CARBON

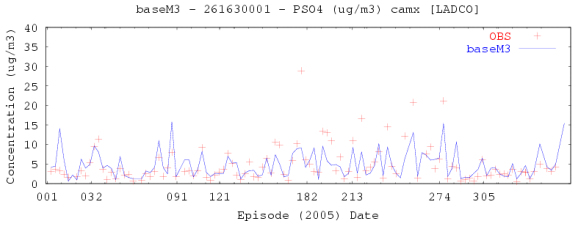
Seney

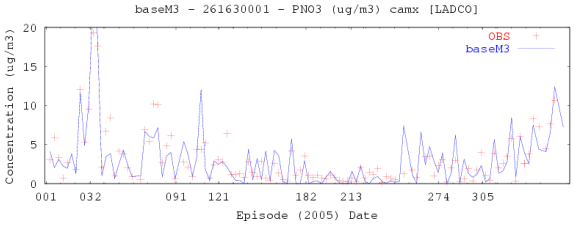


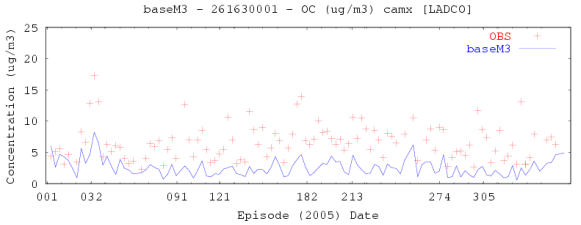




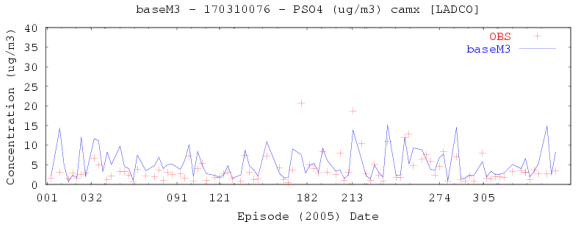
Detroit

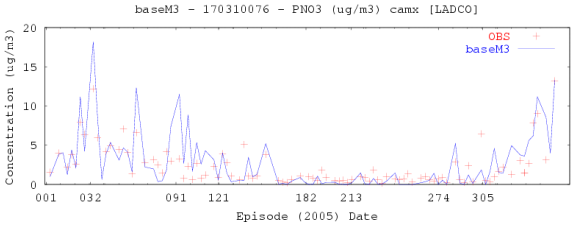






Chicago





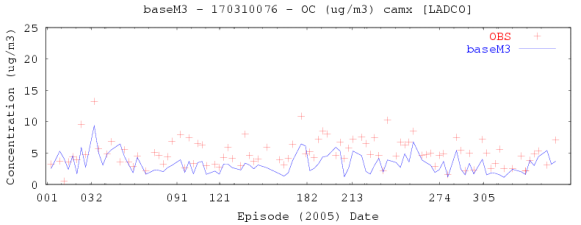


Figure 58. Time series of sulfate, nitrate, and organic carbon at three Midwest sites for 2005

In summary, model performance for ozone and $PM_{2.5}$ is generally acceptable and can be characterized as follows:

Ozone

- Good agreement between modeled and monitored concentration for higher concentration levels (> 60 ppb) – i.e., bias within 30%

- Regional modeled concentrations appear to be underestimated in the 2002 base year, but show better agreement (with monitored data) in the 2005 base year due to model and inventory improvements.

- Day-to-day and hour-to-hour variation in and spatial patterns of modeled concentrations are consistent with monitored data

- Model accurately simulates the change in monitored ozone concentrations due to reductions in precursor emissions.

$PM_{2.5}$

- Good agreement in the magnitude of fine particle mass, but some species are overestimated and some are underestimated (during periods of the year when it is important)
    - Sulfates: good agreement in the 2002 base year, but underestimated in the summer in the 2005 base year due probably to meteorological factors
    - Nitrates: slightly overestimated in the winter in the 2002 base year, but good agreement in the 2005 base year as a result of model and inventory improvements
    - Organic Carbon: grossly underestimated in the 2002 and 2005 base years due likely to missing primary organic carbon emissions and, possibly, other factors (e.g., grid resolution and model chemistry).

- Temporal variation and spatial patterns of modeled concentrations are consistent with monitored data

Several observations should be noted on the implications of these model performance findings on the attainment modeling presented in the following section. First, it has been demonstrated that model performance overall is acceptable and, thus, the model can be used for air quality planning purposes. Second, consistent with EPA guidance, the model is used in a relative sense to project future year values. EPA suggests that this approach "should reduce some of the uncertainty attendant with using absolute model predictions alone" (EPA, 2007a). Furthermore, the attainment modeling is supplemented by additional information to provide a weight of evidence determination.

Section 4.0 Attainment Demonstration for Ozone and $PM_{2./5}$

Air quality modeling and other information were used to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the NAAQS for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Traditionally, attainment demonstrations involved a "bright line" test in which a single modeled value was compared to the ambient standard. To provide a more robust assessment of expected future year air quality, EPA's modeling guidelines call for consideration of supplemental information. This section summarizes the results of the primary (guideline) modeling analysis and a weight of evidence determination based on the modeling results and other supplemental analyses.

4.1 Future Year Modeling Results

The purpose of the future year modeling is to assess the effectiveness of existing and possible additional control programs. The model was used in a relative sense to project future year values, which are then compared to the standard to determine attainment/nonattainment. Specifically, the modeling test consists of the following steps:

(1) Calculate base year design values: For ozone and $PM_{2.5}$, the base year design values were derived by averaging the three 3-year periods centered on the emissions base year:

2002 base year: 2000-2002, 2001-2003, and 2002-2004
2005 base year: 2003-2005, 2004-2006, and 2005-2007[11]

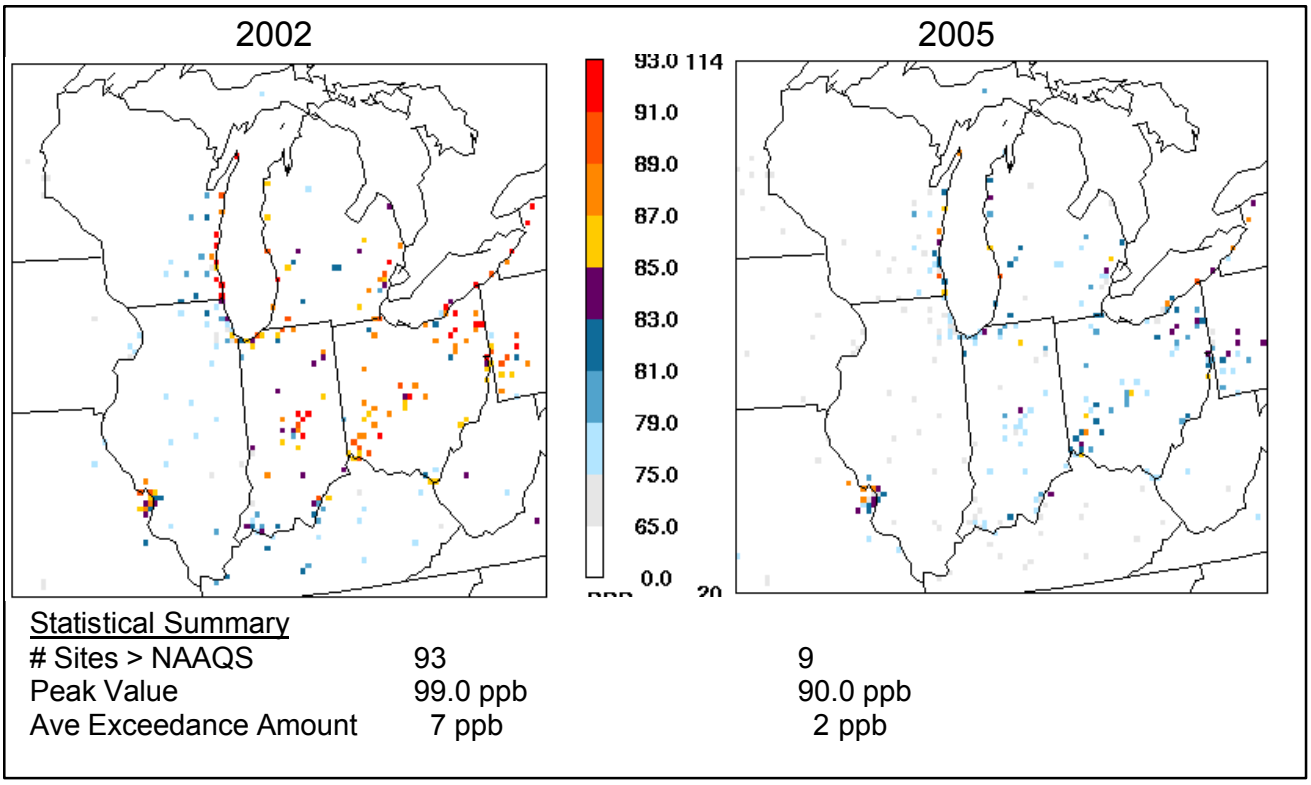
(2) Estimate the expected change in air quality: For each grid cell, a relative reduction factor (RRF) is calculated by taking the ratio of the future year and baseline modeling results.

(3) Calculate future year values: For each grid cell (with a monitor), the RRFs are multiplied by the base year design values to project the future year values

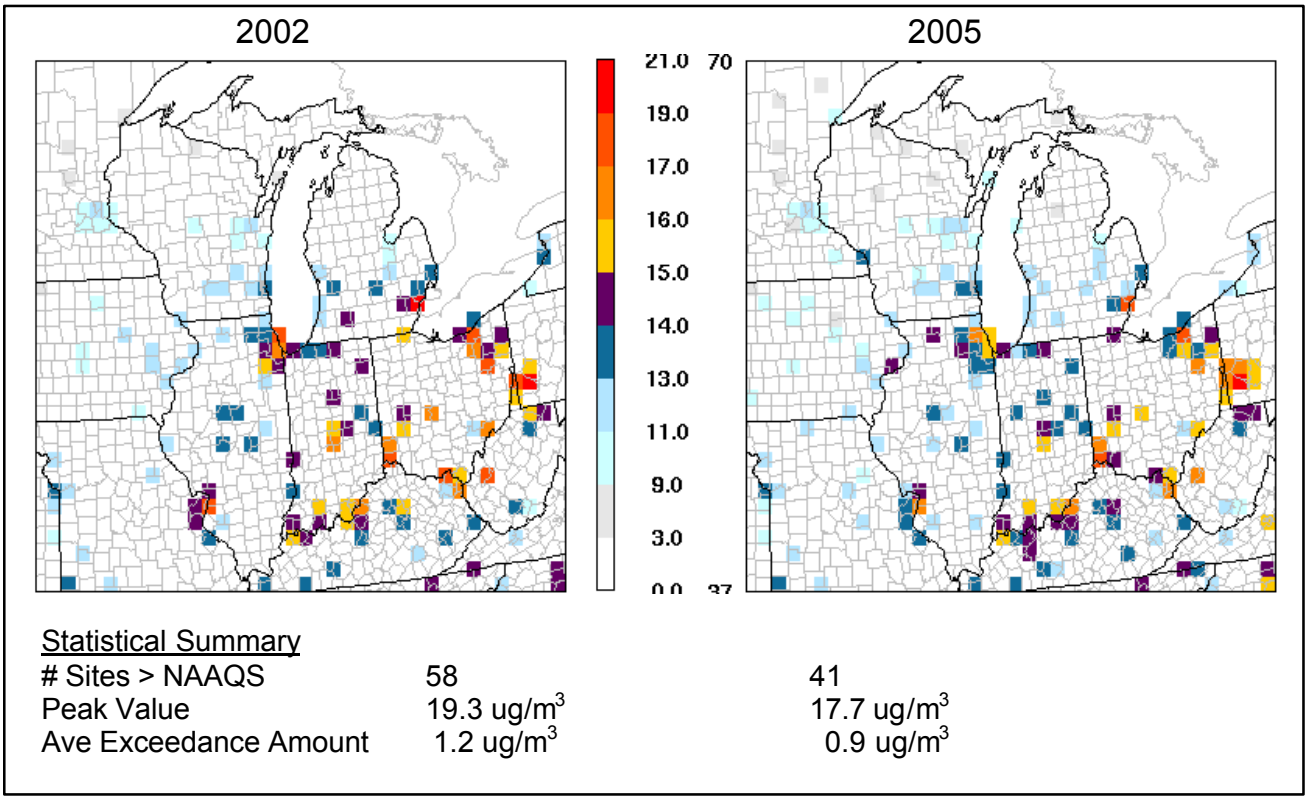
(4) Assess attainment: Future year values are compared to the NAAQS to assess attainment or nonattainment.

A comparison of the 2002 and 2005 base year design values for ozone and $PM_{2.5}$ is provided in Figure 59. In general, the figure shows that the 2005 base year design values are much lower than the 2002 base year design values, especially for ozone.

[11] A handful of source-oriented PM2.5 monitors in Illinois and Indiana were excluded from the annual attainment test, because these monitors are not to be used to judging attainment of the annual standard.



Statistical Summary		
# Sites > NAAQS	93	9
Peak Value	99.0 ppb	90.0 ppb
Ave Exceedance Amount	7 ppb	2 ppb



Statistical Summary		
# Sites > NAAQS	58	41
Peak Value	19.3 ug/m^3	17.7 ug/m^3
Ave Exceedance Amount	1.2 ug/m^3	0.9 ug/m^3

Figure 59. 2002 v. 2005 base year design values for ozone (top) and $PM_{2.5}$ (bottom)

Ozone results are provided for those grid cells with ozone monitors. The RRF calculation considers all nearby grid cells (i.e., 3x3 for 12 km modeling) and a threshold of 85 ppb. (If there were less than 10 days above this value, then the threshold was lowered until either there were 10 days or the threshold reached 70 ppb.) $PM_{2.5}$ results are provided for those grid cells with FRM ($PM_{2.5}$-mass) monitors. Spatial mapping was performed to extrapolate $PM_{2.5}$-speciation data from STN and IMPROVE sites to FRM sites. RRF values for $PM_{2.5}$ were derived as a function of quarter and chemical species.

Additional, hot-spot modeling will be performed by the states for certain $PM_{2.5}$ nonattainment areas (e.g., Detroit, Cleveland, and Granite City) to address primary emissions from local point sources which may not be adequately accounted for by the regional grid modeling. This modeling will consist of Gaussian dispersion modeling (e.g., AERMOD) performed in accordance with EPA's modeling guidance (see Section 5.3 of the April 2007 guidance document). Further analyses will need to be undertaken to determine how to best combine the regional modeling and the hot-spot modeling. This could mean some adjustment to the model results presented in this document to reflect better the regional component.

The ozone and $PM_{2.5}$ modeling results are provided in Appendix I for select monitors (high concentration sites) in the 5-state region for the following future years of interest: 2008 (ozone only), 2009, 2012, and 2018. (Note, RRF values for ozone, and for $PM_{2.5}$ by season and chemical species are also included in Appendix I for key monitoring sites.) A summary of the modeling results is provided in Table 9 (ozone) and Table 10 ($PM_{2.5}$), and spatial maps of the Base M future year concentrations are provided in Figures 60-62.

Table 9. Summary of Ozone Modeling Results									
Key Sites		**2008**		**2009**		**2012**		**2018**
		Round 5	Round 4	Round 5	Round 4	Round 5	Round 4	Round 5
Lake Michigan Area								
Chiwaukee	550590019	82.0	**93.0**	82.3	**92.0**	80.9	**90.3**	76.2
Racine	551010017	77.6	**85.9**	77.5	84.9	76.1	82.9	71.2
Milwaukee-Bayside	550190085	79.6	**85.4**	79.8	84.9	78.0	82.3	72.7
Harrington Beach	550890009	80.0	**86.7**	80.1	**85.4**	78.3	82.9	72.5
Manitowoc	550710007	81.3	80.3	80.8	78.9	78.6	76.3	72.5
Sheboygan	551170006	84.4	**90.0**	84.0	**88.9**	81.8	**86.4**	75.4
Kewaunee	550610002	78.9	82.5	78.1	81.0	75.9	79.1	69.9
Door County	550290004	84.8	83.6	83.9	81.8	81.5	79.3	74.7
Hammond	180892008	75.4	**86.9**	75.4	**86.6**	74.6	**86.3**	71.6
Whiting	180890030	77.0		77.0		76.2		73.1
Michigan City	180910005	74.2	**87.4**	73.9	**86.5**	72.5	**85.4**	68.1
Ogden Dunes	181270020	75.7	82.3	75.6	82.8	74.5	82.0	70.8
Holland	260050003	**85.6**	84.9	**85.3**	83.4	82.8	81.0	76.1
Jenison	261390005	77.9	78.7	77.1	77.6	74.5	75.5	68.7
Muskegon	261210039	80.8	82.7	80.5	81.5	78.0	79.4	71.9
Indianapolis Area								
Noblesville	189571001	78.0	**85.2**	78.1	83.7	75.6	82.0	68.7
Fortville	180590003	73.9	**85.1**	73.9	83.8	71.4	82.1	65.1
Fort B. Harrison	180970050	74.8	84.8	75.1	83.7	73.2	82.4	69.1
Detroit Area								
New Haven	260990009	82.7	**86.3**	81.4	**85.3**	80.2	83.5	76.1
Warren	260991003	82.5	84.3	81.3	83.3	80.7	81.9	77.6
Port Huron	261470005	79.0	80.5	77.5	79.1	75.5	77.0	70.9
Cleveland Area								
Ashtabula	390071001	84.9	84.7	83.4	82.7	81.0	80.2	75.1
Geauga	390550004	75.7	**90.3**	74.7	**88.8**	72.7	**86.2**	67.3
Eastlake	390850003	82.8	84.2	81.9	82.8	80.5	80.6	76.2
Akron	391530020	79.3	83.0	78.1	81.4	75.6	78.5	68.7
Cincinnati Area								
Wilmington	390271002	77.8	84.8	77.5	83.5	74.9	81.1	68.3
Sycamore	390610006	81.7	**85.4**	81.9	84.7	80.3	82.9	74.6
Lebanon	391650007	83.6	80.1	83.0	79.0	80.7	77.0	74.2
Columbus Area								
London	390970007	75.4	79.9	75.0	78.4	72.6	76.5	66.3
New Albany	390490029	82.4	84.1	81.8	82.6	79.6	80.2	73.0
Franklin	290490028	77.0	77.7	75.9	76.5	74.1	74.7	69.0
St. Louis Area								
W. Alton (MO)	291831002	82.4	**86.1**	81.0	**85.2**	78.6	84.0	74.9
Orchard (MO)	291831004	83.3	83.3	82.0	82.2	80.0	80.4	76.2
Sunset Hills (MO)	291890004	79.5	82.8	78.7	81.9	77.1	80.6	73.9
Arnold (MO)	290990012	78.7	78.4	77.2	77.4	75.6	75.8	72.0
Margaretta (MO)	295100086	79.8	84.0	79.3	83.4	77.9	82.5	74.4
Maryland Heights (MO)	291890014	84.5		83.4		81.7		78.1

Table 10. Summary of PM2.5 Modeling Results								
			2009		2012		2018	
County	**Site ID**	**Site**	**Round 5**	**Round4**	**Round 5**	**Round4**	**Round 5**	**Round4**
Cook	170310022	Chicago - Washington HS	14.1	14.8	14.0	14.6	13.9	14.4
Cook	170310052	Chicago - Mayfair	14.4	**15.8**	14.2	**15.5**	13.9	**15.0**
Cook	170310057	Chicago - Springfield	13.9	14.5	13.8	14.3	13.7	14.1
Cook	170310076	Chicago - Lawndale	13.8	14.5	13.7	14.3	13.6	14.1
Cook	170312001	Blue Island	13.7	14.5	13.6	14.3	13.4	14.1
Cook	170313301	Summit	14.2	14.8	14.0	14.6	13.9	14.4
Cook	170316005	Cicero	14.4	**15.3**	14.3	**15.1**	14.2	14.9
Madison	171191007	Granite City	**15.1**	**16.0**	14.9	**15.8**	14.3	**15.5**
St. Clair	171630010	E. St. Louis	14.1	14.9	13.9	14.7	13.4	14.5
Clark	180190005	Jeffersonville	13.8	**15.5**	13.7	**15.0**	13.4	14.4
Dubois	180372001	Jasper	12.4	13.8	12.2	13.5	11.8	13.0
Lake	180890031	Gary	13.0		12.8		12.4	
Marion	180970078	Indy-Washington Park	12.8	14.5	12.6	14.2	12.0	13.7
Marion	180970083	Indy- Michigan Street	13.4	14.8	13.1	14.9	12.6	14.0
Wayne	261630001	Allen Park	13.0	14.5	12.8	14.1	12.4	13.3
Wayne	261630015	Southwest HS	14.2	**15.8**	13.9	**15.3**	13.5	14.4
Wayne	261630016	Linwood	13.1	14.1	12.8	13.7	12.5	13.0
Wayne	261630033	Dearborn	**15.8**	**17.7**	**15.5**	**17.1**	**15.1**	**16.1**
Wayne	261630036	Wyandotte	13.1	**15.1**	12.8	14.7	12.5	13.9
Butler	390170003	Middleton	13.5	14.2	13.2	13.7	12.8	13.1
Butler	390170016	Fairfield	13.1	13.5	12.9	12.9	12.5	12.2
Cuyahoga	390350027	Cleveland-28th Street	13.5	14.4	13.2	13.8	12.7	12.9
Cuyahoga	390350038	Cleveland-St. Tikhon	**15.2**	**16.1**	14.8	**15.4**	14.3	14.4
Cuyahoga	390350045	Cleveland-Broadway	14.4	14.6	14.0	14.0	13.5	13.1
Cuyahoga	390350060	Cleveland-GT Craig	15.0	**15.3**	14.6	14.7	14.1	13.7
Cuyahoga	390350065	Newburg Hts - Harvard Ave	14.0	14.1	13.6	13.5	13.1	12.6
Franklin	390490024	Columbus - Fairgrounds	12.9	14.6	12.6	14.0	12.0	13.0
Franklin	390490025	Columbus - Ann Street	12.7	14.1	12.4	13.5	11.9	12.5
Franklin	390490081	Columbus - Maple Canyon	11.7	14.0	11.4	13.4	10.9	12.5
Hamilton	390610014	Cincinnati - Seymour	14.5	**15.5**	14.3	14.8	13.8	14.0
Hamilton	390610040	Cincinnati - Taft Ave	12.8	13.6	12.6	13.0	12.2	12.3
Hamilton	390610042	Cincinnati - 8th Ave	14.0	14.6	13.8	14.0	13.4	13.2
Hamilton	390610043	Sharonville	12.9	13.6	12.7	13.0	12.3	12.2
Hamilton	390617001	Norwood	13.4	14.2	13.2	13.6	12.8	12.8
Hamilton	390618001	St. Bernard	14.7	**15.2**	14.4	14.6	14.0	13.8
Jefferson	390810016	Steubenville	12.8	**16.3**	12.5	**15.9**	12.7	**16.2**
Jefferson	390811001	Mingo Junction	13.5	**15.5**	13.2	**15.0**	13.4	**15.3**
Lawrence	390870010	Ironton	12.8	14.2	12.5	13.7	12.3	13.2
Montgomery	391130032	Dayton	13.2	13.7	12.9	13.2	12.4	12.3
Scioto	391450013	New Boston	12.1	**15.4**	11.9	14.8	11.6	14.2
Stark	391510017	Canton - Dueber	14.0	**15.0**	13.6	14.3	13.3	13.6
Stark	391510020	Canton - Market	12.6	13.6	12.3	13.0	11.9	12.2
Summit	391530017	Akron - Brittain	13.0	14.4	12.7	13.6	12.3	12.9
Summit	391530023	Akron - W. Exchange	12.3	13.6	12.0	13.0	11.5	12.2

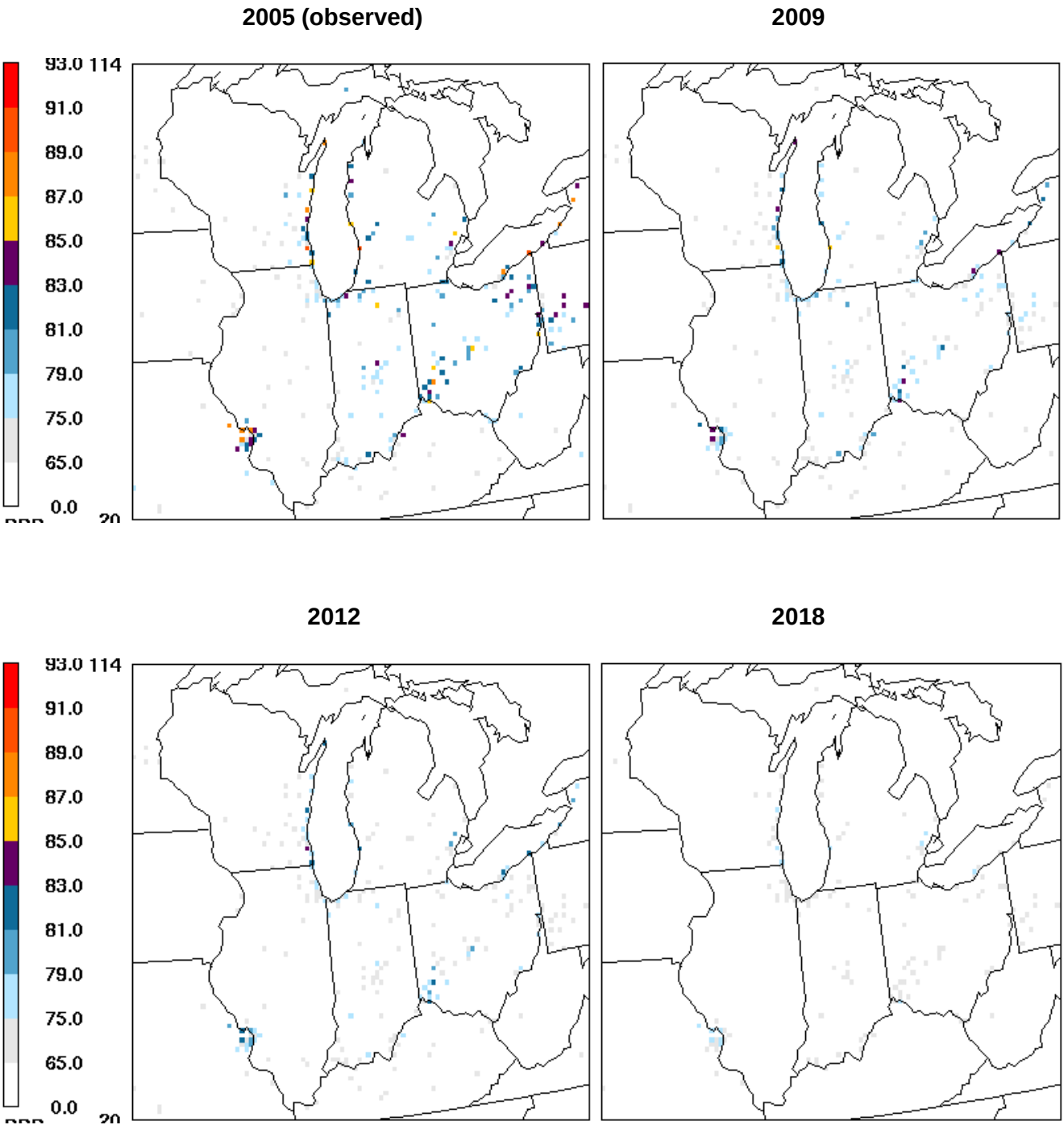


Figure 60. Observed base year and projected future year design values for ozone – Base M

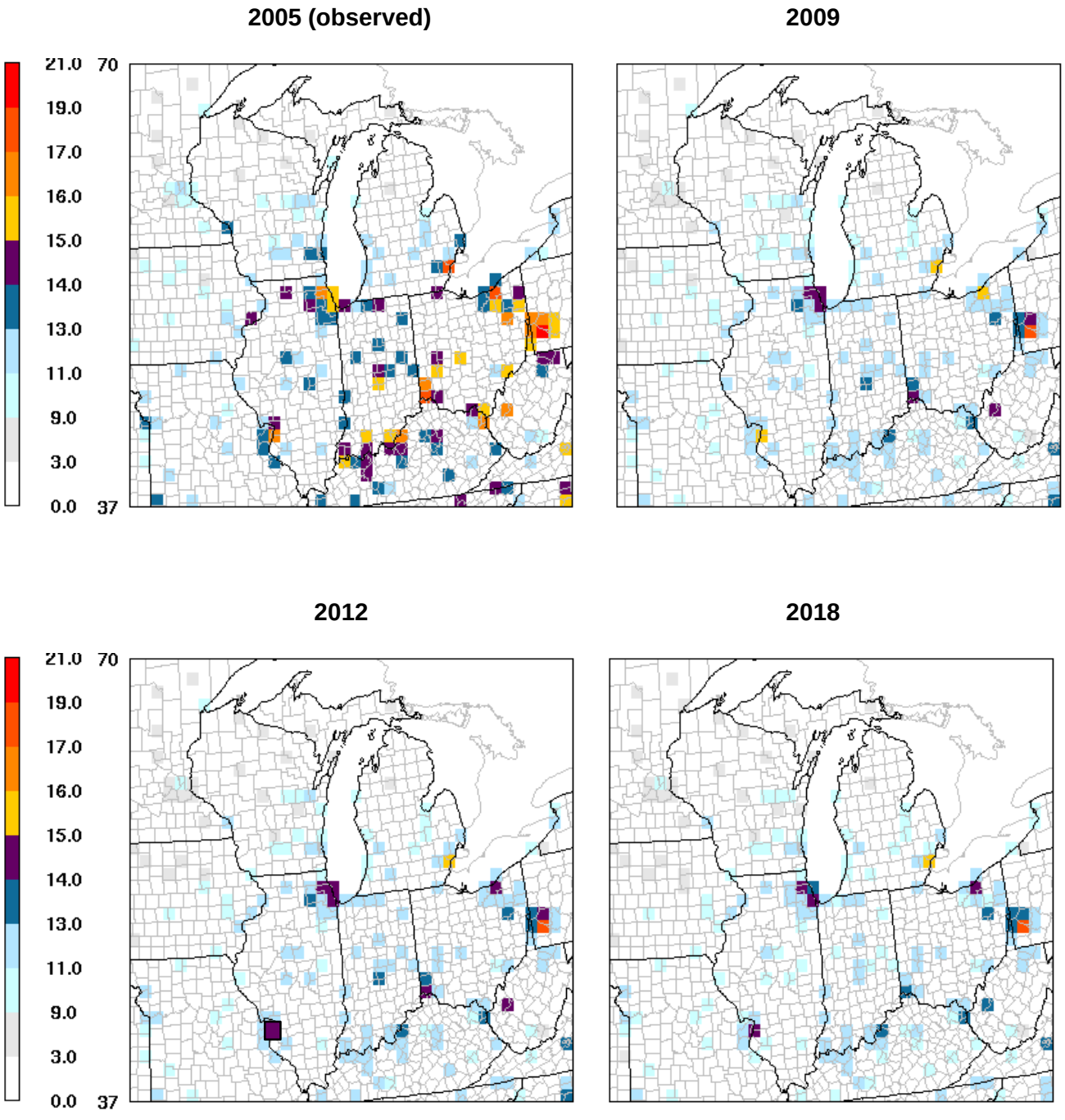


Figure 61. Observed base year and projected future year design values for $PM_{2.5}$ (annual average)–Base M

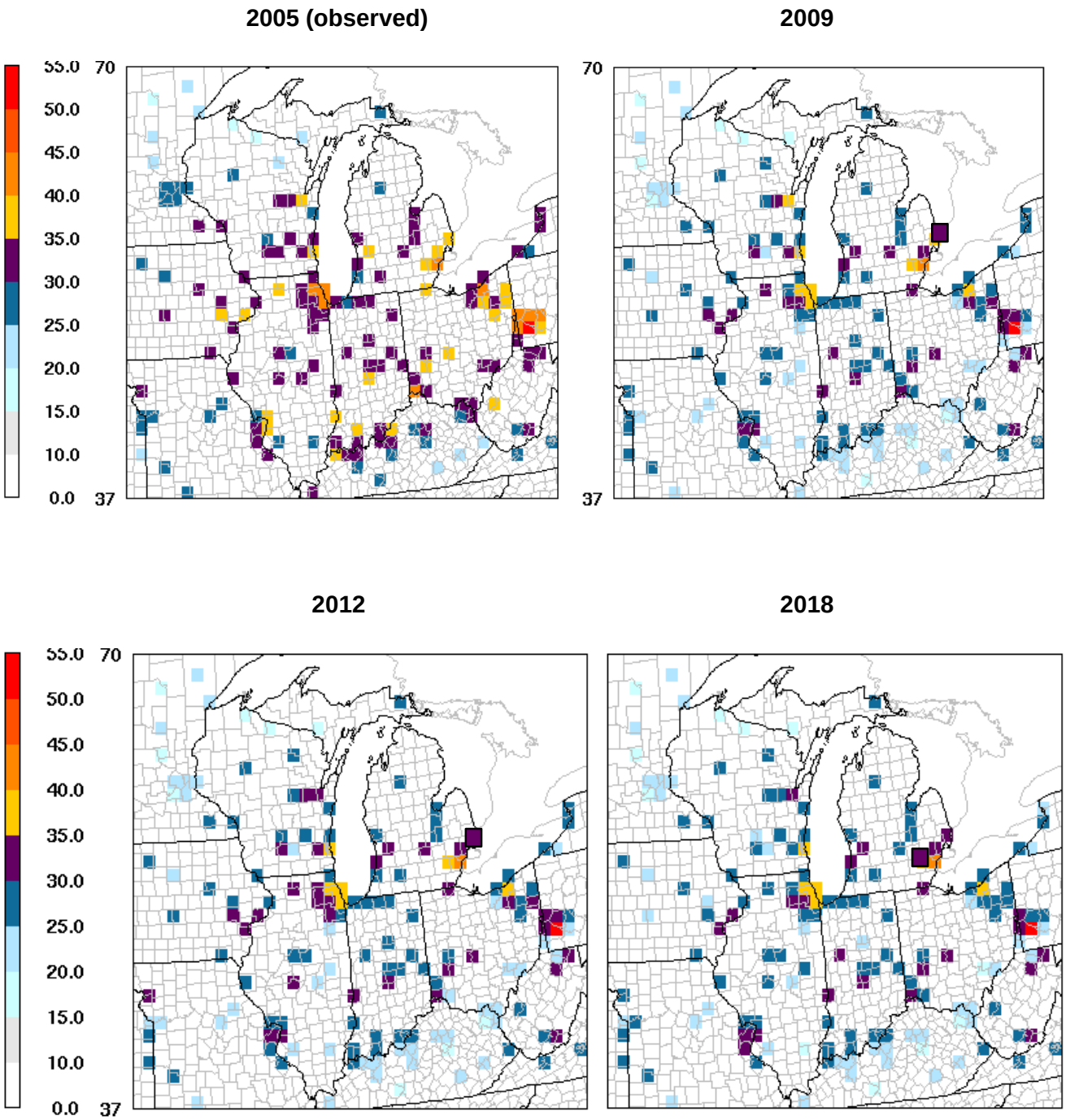


Figure 62. Observed base year and projected future year design values for $PM_{2.5}$ (24-hr average)-Base M

The number of monitors with design values above the standard are as follows:

Table 11. Number of sites above standard

Ozone (8 hour: 85 ppb)										
State	2002	2005		2009			2012			2018	
	BaseK	Base M		BaseK	Base M		BaseK	Base M		BaseK	Base M
IL	3	0		0	0		0	0		0	0
IN	22	0		0	0		0	0		0	0
MI	15	3		1	1		0	0		0	0
OH	40	4		1	0		1	0		0	0
WI	13	2		4	0		3	0		1	0
Total	93	9		6	1		4	0		1	0
PM2.5 (Annual: 15 ug/m^3)										
State	2002	2005		2009			2012			2018	
	BaseK	Base M		BaseK	Base M		BaseK	Base M		BaseK	Base M
IL	11	7		3	1		3	0		2	0
IN	10	6		1	0		1	0		0	0
MI	6	2		3	1		2	1		0	0
OH	31	26		7	1		4	0		1	1
WI	0	0		0	0		0	0		2	0
Total	58	41		14	3		10	1		5	1

The modeling results above reflect the "base" controls identified in Section 3.6, with EGU emissions based on IPM modeling (i.e., Round 4 – IPM2.1.9, and Round 5 – IPM3.0). In addition, two sets of alternative future year EGU emissions were examined in Round 5. First, alternative control assumptions were provided for several facilities by the states (i.e., "will do" and "may do" scenarios). In general, these scenarios produced a small change in future year ozone and $PM_{2.5}$ concentrations (i.e., about 0.1 ug/m^3 for $PM_{2.5}$ and 0.1-0.2 ppb for ozone). Second, EPA suggested adjustments to the 2010 IPM emissions to reflect 2009 conditions. The revised (2009) SO2 emissions represent a 5-6% increase in domainwide SO2 emissions. The increased SO2 emissions result in slightly greater annual average $PM_{2.5}$ concentrations (on the order of 0.1 – 0.2 ug/m^3), but do not produce any new residual nonattainment areas.

The limited 4 km ozone modeling (based on Base K) performed by LADCO included a future year analysis for 2009. The figure below shows the 2009 values with 12 km and 4 km grid spacing for the LADCO modeling and similar modeling conducted by a stakeholder group (Midwest Ozone Group).

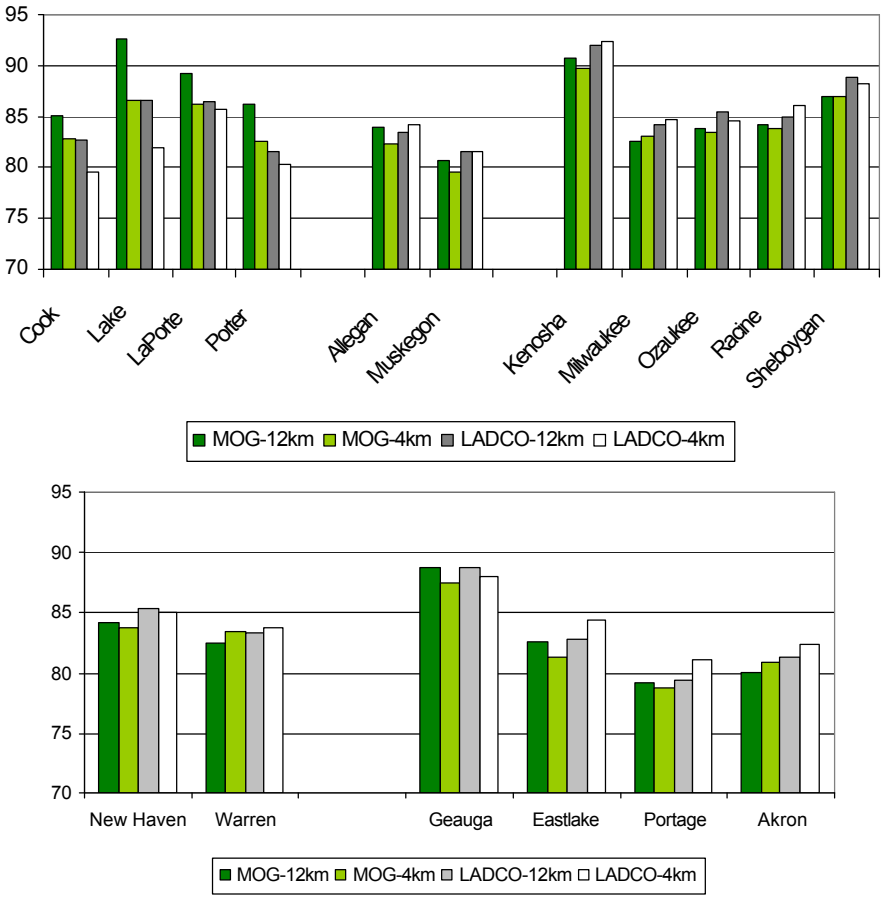


Figure 63. Future year (2009) values for Lake Michigan area (top) and Detroit-Cleveland region (bottom)

These results show that the 12 km and 4 km values are similar, with the most notable changes in northwestern Indiana and northeastern Illinois (e.g., 4 km values are as much as 4 ppb lower than 12 km values). The differences in the southern part of the Lake Michigan area are plausible, given the tight emissions gradient there (i.e., finer grid resolution appears to provide more appropriate representation).

In light of these findings, 12 km grid spacing can continue to be used for ozone modeling, but the Base K/Round 4 results for northwestern Indiana/northeastern Illinois should be viewed with caution (i.e., probably 1 – 4 ppb too high).

In summary, the ozone modeling provides the following information for the nonattainment areas in the region (see Table 12):

Table 12. Ozone Nonattainment Areas in the LADCO Region (as of December 31, 2007)

Area Name	Category	Number of Counties	Attainment Deadline
Detroit-Ann Arbor, MI	Marginal	8	2007
Chicago-Gary-Lake County, IL-IN	Moderate	10	2010
Cleveland-Akron-Lorain, OH	Moderate	8	2010
Milwaukee-Racine, WI	Moderate	6	2010
Sheboygan, WI	Moderate	1	2010
St Louis, MO-IL	Moderate	4	2010
Allegan Co, MI	Subpart 1	1	2009
Cincinnati-Hamilton, OH-KY-IN	Subpart 1	6	2009
Columbus, OH	Subpart 1	6	2009
Door Co, WI	Subpart 1	1	2009
Kewaunee Co, WI	Subpart 1	1	2009
Manitowoc Co, WI	Subpart 1	1	2009
		53	

Marginal Areas (2007 attainment date): No modeling was conducted for the 2006 SIP planning year. Rather, 2005 – 2007 air quality data are available to determine attainment.

Basic (Subpart 1) Areas (2009 attainment date): The modeling results for the 2008 SIP planning year show:

- Base K: all areas in attainment, except Cincinnati and Indianapolis
- Base M: all areas in attainment, except Holland (Allegan County)

Moderate Areas (2010 attainment date): The modeling results for the 2009 SIP planning year show:

- Base K: all areas still in nonattainment
- Base M: all areas in attainment

The $PM_{2.5}$ modeling results show:

- Base K: all areas in attainment, except for Chicago, Cincinnati, Cleveland, Detroit, Granite City (IL), Louisville, Portsmouth (OH), and Steubenville
- Base M: all areas in attainment, except for Cleveland, Detroit, and Granite City (IL)

With respect to the new lower 8-hour ozone standard, the modeling about 30 sites in 2012 and 5 sites in 2018 with design values greater than 75 ppb. With respect to the new lower 24-hour $PM_{2.5}$ standard, the modeling shows 13 sites in 2012 and 10 in 2018 with design values greater than 35 ug/m^3.

4.2 Supplemental Analyses

EPA's modeling guidelines recommend that attainment demonstrations consist of a primary (guideline) modeling analysis and supplemental analyses. Three basic types of supplemental analyses are recommended:

- additional modeling
- analyses of trends in ambient air quality and emissions, and
- observational models and diagnostic analyses

Furthermore, according to EPA's guidelines, if the future year modeled values are "close" to the standard (i.e., 82 – 87 ppb for ozone and 14.5 – 15.5 ug/m^3 for $PM_{2.5}$), then the results of the primary modeling should be reviewed along with the supplemental information in a "weight of evidence" assessment of whether each area is likely to achieve timely attainment.

A WOE determination for ozone and $PM_{2.5}$ is provided in the following sections. Special attention is given to the following areas with future year modeled values that exceed or are "close" to the ambient standard (see Appendix I):

Ozone	**PM2.5**
Lake Michigan area	Chicago, IL
Cleveland, OH	Cleveland, OH
Cincinnati, OH	Cincinnati, OH
	Granite City, IL
	Detroit, MI

4.3 Weight-of-Evidence Determination for Ozone

The WOE determination for ozone consists of the primary modeling and other supplemental analyses (some of which were discussed in Section 2). A summary of this information is provided below.

Primary (Guideline) Modeling: The guideline modeling is presented in Section 4.1. Key findings from this modeling include:

- Base M regional modeling shows attainment by 2008 and 2009 at all sites, except Holland (MI), and attainment at all sites by 2012.

- Base K modeling results reflect generally higher future year values, and show more sites in nonattainment compared to the Base M modeling. The difference in the two modeling analyses is due mostly to lower base year design values in Base M.

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for ozone should reflect a weight-of-evidence approach, with consideration of monitoring based information.

- Base M modeling also shows that the proposed lower 8-hour standard will not be met at many sites, even by 2018, with existing controls.

Additional Modeling: Four additional modeling analyses were considered: (1) re-examination of the primary modeling to estimate attainment probabilities, (2) remodeling with different assumptions, (3) an unmonitored area analysis, and (4) EPA's latest regional ozone modeling. Each of these analyses is described below.

First, the primary modeling results (which were initially processed using EPA's attainment test) were re-examined to estimate the probability of attaining the ozone standard (Lopez, 2007, and LADCO, 2008b). Seven estimates of future year ozone concentrations were calculated based on model-based RRFs and appropriate monitor-based concentrations for each year between 2001 and 2007. RRF values for 2001, 2003, 2004, 2006, and 2007 were derived based on the 2002 and 2005 modeling results. Monitor-based concentrations reflect 4th high values, design values, or average of three design values centered on the year in question. The probability of attainment was determined as the percentage of these seven estimates below the standard. The results indicate that sites in the Lake Michigan area (Chiwaukee, Sheboygan, Holland, Muskegon), Cleveland (Ashtabula), and St. Louis (W Alton) have a fairly low probability of attainment by 2009 (i.e., about 50% or less).

Second, the primary modeling analysis was redone with different types of assumptions for calculating base year design values (i.e., using the 3-year period centered on base year, and using the highest 3-year period that includes the base year), and for calculating RRFs (i.e., using all days with base year modeled value > 70 ppb, and using all days with base year modeled value > 85 ppb, with at least 10 days and "acceptable" model performance). The results for several high concentration sites are presented in Tables 13a and 13b for 2009. The different modeling assumptions produce eight estimates of future year ozone concentrations. The highest estimates are associated with base year design values representing the 3-year average for 2001-2003, and the lowest estimates are associated with base year design values representing the 3-year average 2004-2006. The different RRF approaches produce little change in future year ozone concentrations. This suggests that future year concentration estimates are most sensitive to the choice of the base year and the methodology used to derive the base year design values.

Third, EPA's modeling guidelines recommend that an "unmonitored area analysis" be included as a supplemental analysis, particularly in nonattainment areas where the monitoring network just meets or minimally exceeds the size of the network required to report data to EPA's Air Quality System. The purpose of this analysis is to identify areas where future year values are predicted to be greater than the NAAQS.

Based on examination of the spatial plots in Figures 49a and 49b, the most notable areas of high modeled ozone concentrations are over the Great Lakes. Over-water monitoring, however, is not required by EPA[12]. A cursory analysis of unmonitored areas for ozone was performed by LADCO using an earlier version of the 2002 base year modeling (i.e, Base I) (Baker, 2005). Base year and future year "observed" values were derived for unmonitored grid cells using the absolute modeled concentrations (in all grid cells) and the observed values (in monitored grid cells). A spatial map of the estimated 2009 values is provided in Figure 64. As can be seen, there are very few (over land) grid cells where additional monitors may be desirable. This indicates that the current modeling analysis, which focuses on monitored locations, is addressing areas of high ozone throughout the region.

[12] Air quality measurements over Lake Michigan were collected by LADCO previously to understand ozone transport in the area (see, for example, Figure 5). Due to cut-backs in USEPA funding, however, these measurements were discontinued in 2003.

Table 13a. Primary and Additional Ozone Modeling Results – Lake Michigan and Cleveland Areas (2009)

2009 Modeling Results		Lake Michigan Area								Cleveland Area		
		Chiwaukee	Harr.Beach	Sheboygan	DoorCounty	Holland	Hammond	MichiganCity		Ashtabula	Geauga	Eastlake
		550590019	550890009	551170006	550290004	260050003	180892008	180910005		390071001	390550004	390850003
Attainment Test (based on EPA guidance-2002 baseyear)												
Base Year Design Value (average of three 3-year periods)		*98.3*	*93.0*	*97.0*	*91.0*	*94.0*	*88.3*	*90.3*		*95.7*	*99.0*	*92.7*
RRF (all days > 85 ppb, or at least 10 days)		0.935	0.918	0.916	0.899	0.888	0.980	0.958		0.865	0.897	0.894
Future Year Design Value		**91.9**	**85.4**	**88.9**	**81.8**	83.5	**86.5**	**86.5**		82.8	**88.8**	82.9
Attainment Test (based on EPA guidance-2005 baseyear)												
Base Year Design Value (average of three 3-year periods)		*84.7*	*83.3*	*88.0*	*88.7*	*90.0*	*77.7*	*77.0*		*89.0*	*79.3*	*86.3*
RRF (all days > 85 ppb, or at least 10 days)		0.972	0.961	0.955	0.946	0.948	0.971	0.960		0.937	0.942	0.949
Future Year Design Value		82.3	80.1	84.0	83.9	**85.3**	75.4	73.9		83.4	74.7	81.9
Weight of Evidence (alternative approaches-2002baseyear)												
Alt 1 - Base Year Des. Value (3-year period centered on 2002)		*101.0*	*98.0*	*100.0*	*94.0*	*97.0*	*90.0*	*93.0*		*99.0*	*103.0*	*95.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2002)		*101.0*	*98.0*	*100.0*	*94.0*	*97.0*	*92.0*	*93.0*		*99.0*	*103*	*95.0*
RRF (all days > 85 ppb, or at least 10 days)		0.935	0.918	0.916	0.899	0.888	0.980	0.958		0.865	0.897	0.894
Alt 1 - Future Year Projected Value		**94.4**	**90.0**	**91.6**	84.5	**86.1**	**88.2**	**89.1**		**85.6**	**92.4**	84.9
Alt 2 - Future Year Projected Value		**94.4**	**90.0**	**91.6**	84.5	**86.1**	**90.2**	**89.1**		**85.6**	**92.4**	84.9
Alt 1 - RRF (all days > 70 ppb)		0.933	0.918	0.912	0.907	0.893	0.969	0.947		0.876	0.907	0.900
Alt 1 - Future Year Projected Value		**94.2**	**90.0**	**91.2**	**85.3**	**86.6**	**87.2**	**88.1**		**86.7**	**93.4**	**85.5**
Alt 2 - Future Year Projected Value		**94.2**	**90.0**	**91.2**	**85.3**	**86.6**	**89.1**	**88.1**		**86.7**	**93.4**	**85.5**
Alt 2 - RRF (all days > 85 ppb, or at least 10 days; with acceptable model performance)		0.945	0.904	0.910	0.904	0.887	0.976	0.964		0.866	0.896	0.894
Alt 1 - Future Year Projected Value		**95.4**	**88.6**	**91.0**	**85.0**	**86.0**	**87.8**	**89.7**		**85.7**	**92.3**	84.9
Alt 2 - Future Year Projected Value		**95.4**	**88.6**	**91.0**	**85.0**	**86.0**	**89.8**	**89.7**		**85.7**	**92.3**	84.9
Weight of Evidence (alternative approaches-2005baseyear)												
Alt 1 - Base Year Des. Value (3-year period centered on 2005)		*83.0*	*79.0*	*86.0*	*86.0*	*88.0*	*76.0*	*76.0*		*86.0*	*77.0*	*86.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2005)		*86.0*	*88.0*	*89.0*	*90.0*	*93.0*	*79.0*	*78.0*		*91.0*	*86.0*	*89.0*
Alt 1 - Future Year Projected Value		80.7	75.9	82.1	81.4	83.4	73.8	73.0		80.6	72.5	81.6
Alt 2 - Future Year Projected Value		83.6	84.6	**85.0**	**85.1**	**88.2**	76.7	74.9		**85.3**	81.0	84.5

Table 13b. Primary and Additional Ozone Modeling Results – Cincinnati, Columbus, St. Louis, Indianapolis, and Detroit (2009)

2009 Modeling Results	Cincinnati Area			Columbus	St. Louis Area		Indianapolis Area		Detroit Area
	Wilmington	Lebanon	Sycamore	NewAlbany	W. Alton	OrchardFarm	Noblesville	Fortville	New Haven
	390271002	39165007	390610006	390490029	291831002	291831004	180571001	18059003	260990009
Attainment Test (based on EPA guidance-2002 baseyear)									
Base Year Design Value (average of three 3-year periods)	*94.3*	*90.7*	*90.7*	*94.0*	*90.0*	*90.0*	*93.7*	*91.3*	*92.3*
RRF (all days > 85 ppb, or at least 10 days)	0.885	0.908	0.938	0.888	0.947	0.914	0.894	0.918	0.924
Future Year Design Value	83.5	82.4	**85.1**	83.5	**85.2**	82.3	83.8	83.8	**85.3**
Attainment Test (based on EPA guidance-2005 baseyear)									
Base Year Design Value (average of three 3-year periods)	*82.3*	*87.7*	*84.3*	*86.3*	*86.3*	*87.0*	*83.3*	*78.7*	*86.0*
RRF (all days > 85 ppb, or at least 10 days)	0.941	0.947	0.967	0.947	0.938	0.942	0.945	0.947	0.947
Future Year Design Value	77.4	83.1	81.5	81.7	80.9	82.0	78.7	74.5	81.4
Weight of Evidence (alternative approaches-2002baseyear)									
Alt 1 - Base Year Des. Value (3-year period centered on 2002)	*96.0*	*92.0*	*93.0*	*95.0*	*91.0*	*92.0*	*96.0*	*94.0*	*97.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2002)	*96.0*	*92.0*	*93.0*	*96.0*	*91.0*	*92.0*	*96.0*	*94.0*	*97.0*
RRF (all days > 85 ppb, or at least 10 days)	0.885	0.908	0.938	0.888	0.947	0.914	0.894	0.918	0.924
Alt 1 - Future Year Projected Value	**85.0**	83.5	**87.2**	84.4	**86.2**	84.1	**85.8**	**86.3**	**89.6**
Alt 2 - Future Year Projected Value	**85.0**	83.5	**87.2**	**85.2**	**86.2**	84.1	**85.8**	**86.3**	**89.6**
Alt 1 - RRF (all days > 70 ppb)	0.885	0.914	0.940	0.901	0.945	0.911	0.912	0.907	0.918
Alt 1 - Future Year Projected Value	**85.0**	84.1	**87.4**	**85.6**	**86.0**	83.8	**87.6**	**85.3**	**89.0**
Alt 2 - Future Year Projected Value	**85.0**	84.1	**87.4**	**86.5**	**86.0**	83.8	**87.6**	**85.3**	**89.0**
Alt 2 - RRF (all days > 85 ppb, or at least 10 days; with acceptable model performance)	0.880	0.911	0.940	0.886	0.951	0.913	0.894	0.916	0.935
Alt 1 - Future Year Projected Value	84.5	83.8	**87.4**	84.2	**86.5**	84.0	**85.8**	**86.1**	**90.7**
Alt 2 - Future Year Projected Value	84.5	83.8	**87.4**	**85.1**	**86.5**	84.0	**85.8**	**86.1**	**90.7**
Weight of Evidence (alternative approaches-2005baseyear)									
Alt 1 - Base Year Des. Value (3-year period centered on 2005)	*80.0*	*86.0*	*81.0*	*84.0*	*85.0*	*86.0*	*80.0*	*76.0*	*82.0*
Alt 2 - Base Year Des. Value (Highest 3-year period including 2005)	*85.0*	*89.0*	*86.0*	*88.0*	*89.0*	*89.0*	*87.0*	*81.0*	*90.0*
Alt 1 - Future Year Projected Value	75.3	81.4	78.3	79.5	79.7	81.0	75.6	72.0	77.7
Alt 2 - Future Year Projected Value	80.0	84.3	83.2	83.3	83.5	83.8	82.2	76.7	**85.2**

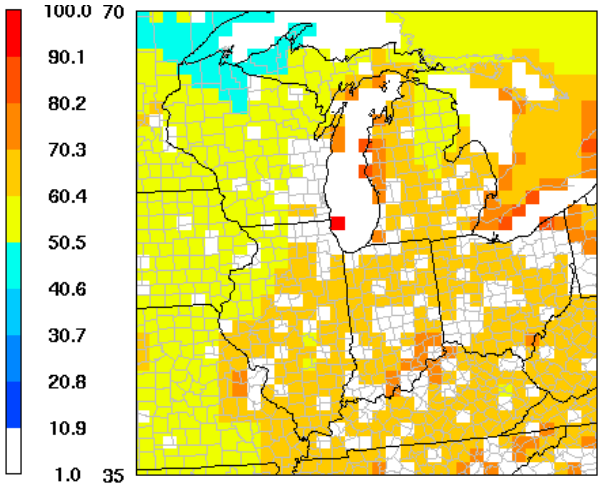


Figure 64. Estimated Future Year Values (unmonitored grid cells)

Finally, EPA's latest regional ozone modeling was considered as corroborative information. This modeling was performed as part of the June 2007 proposal to revise the ozone standard (EPA, 2007b). EPA applied the CMAQ model with 2001 meteorology to first estimate ozone levels in 2020 based on the current standard and national rules in effect or proposed (i.e., the baseline), and then to evaluate strategies for attaining a more stringent (70 ppb) primary standard. Baseline (2020) ozone levels were predicted to be below the current standard in 481 of the 491 counties with ozone monitors. Of the 10 counties predicted to be above the standard, there is one county in the LADCO region (i.e., Kenosha County, WI at 86 ppb). This result is consistent with LADCO's Base K modeling for 2018 (i.e., Kenosha County, WI at 86.7 ppb), which is not surprising given that EPA's modeling and LADCO's Base K modeling have a similar base year (2001 v. 2002).

Analysis of Trends: EPA's modeling guidelines note that while air quality models are generally the most appropriate tools for assessing the expected impacts of a change in emissions, it may also be possible to extrapolate future trends based on measured historical trends of air quality and emissions. To do so, USEPA's guidance suggests that ambient trends should first be normalized to account for year-to-year variations in meteorological conditions (EPA, 2002). Meterologically-adjusted 4th high 8-hour ozone concentrations were derived using the air quality – meteorological regression model developed by EPA (i.e., Cox method – see Section 2.1).

The historical trend in these met-adjusted ozone concentrations were extrapolated to estimate future year ozone concentrations based on historical and projected trends in precursor emissions. Both VOC and NOx emissions affect ozone concentrations. Given that observation-based methods show that urban areas in the region are generally VOC-limited and rural areas in the region are NOx-limited (see Section 2.1), urban VOC emissions and regional NOx emissions are considered important. The trends in urban VOC and regional NOx emissions were calculated to produce appropriate weighting factors.

The resulting 2009 and 2012 ozone values are provided in Figure 65, along with the primary and alternative modeling ozone values for key sites in the Lake Michigan, Cleveland, and Cincinnati areas. The results reflect a fairly wide scatter, but, on balance, the supplemental information is supportive of the primary modeling results (i.e., sites in the Lake Michigan area and Cleveland are expected to be close to the standard).

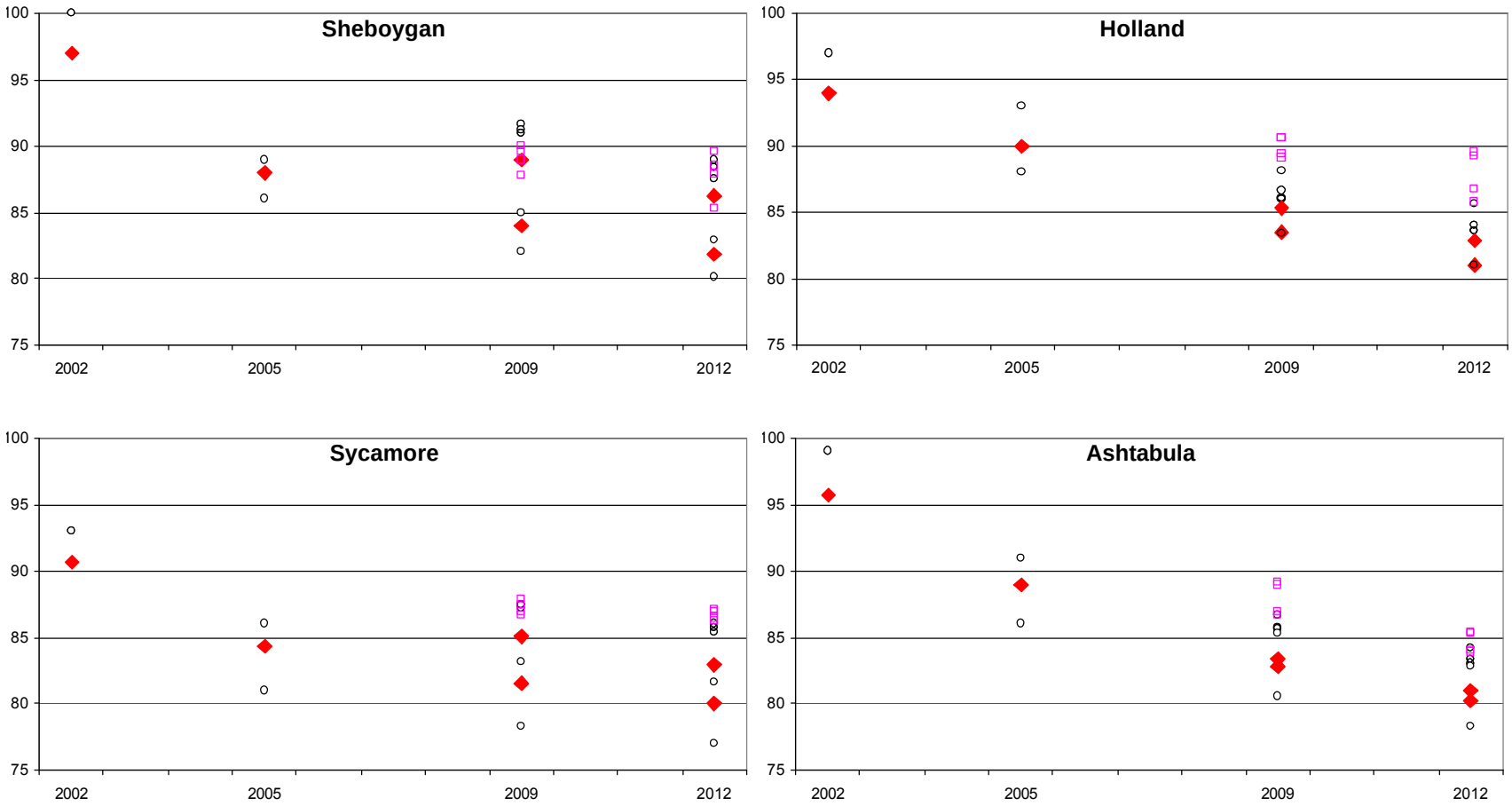


Figure 65. Estimates of Future Year Ozone Concentrations – Lake Michigan Area (Sheboygan and Holland), Cincinnati (Sycamore), and Cleveland (Ashtabula)

Note: Primary (guideline) modeling values (Base K and Base M results) are represented by large red diamonds, additional modeling values by small black circles, and trends-based values by small pink squares

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., MAPPER) is presented in Section 3. The key findings from this modeling are that most urban areas are VOC-limited and rural areas are NOx-limited.

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007a). Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 66) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and biogenic sources) at ozone monitoring sites in the region.

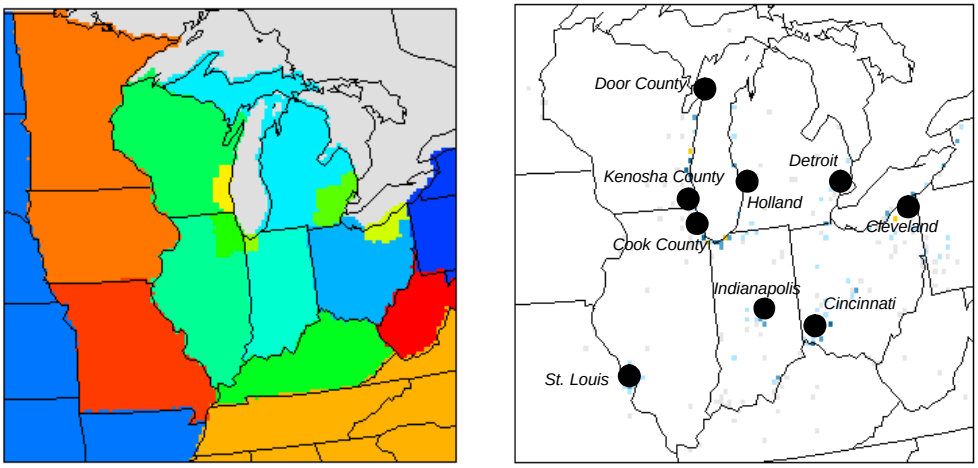


Figure 66. Source regions (left) and key monitoring sites (right) for ozone modeling analysis

Modeling results for 2009 (Base M) and 2012 (Base K) are provided in Appendix II for several key monitoring sites. For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of percentages. (Note, in the sector-level graph, the contributions from NOx emissions are shown in blue, and from VOC emissions in green.)

The sector-level results (see, for example, Figure 67) show that on-road and nonroad NOx emissions generally have the largest contributions at the key monitor locations (> 15% each). EGU and non-EGU NOx emissions are also important contributors (> 10% each). The source group contributions vary by receptor location due to emissions inventory differences.

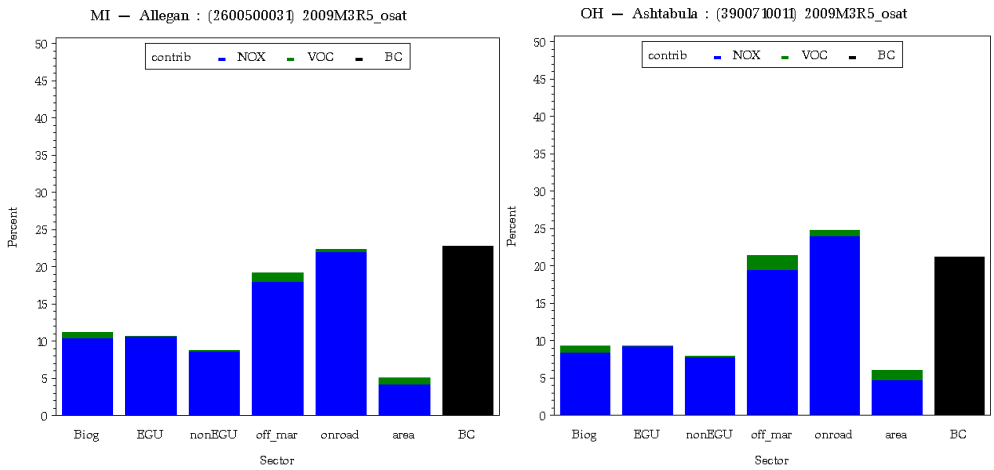


Figure 67. Source-sector results for Holland (left) and Ashtabula (right) monitors – 2009 (Base M)

The source region results (see, for example, Figure 68) show that while nearby areas generally have the highest impacts (e.g., the northeastern IL/northwestern IN/southeastern WI nonattainment area contributes 25-35% to high sites in the Lake Michigan area, and Cleveland nonattainment counties contribute 20-25% to high sites in northeastern Ohio), there is an even larger regional impact (i.e., contribution from other states).

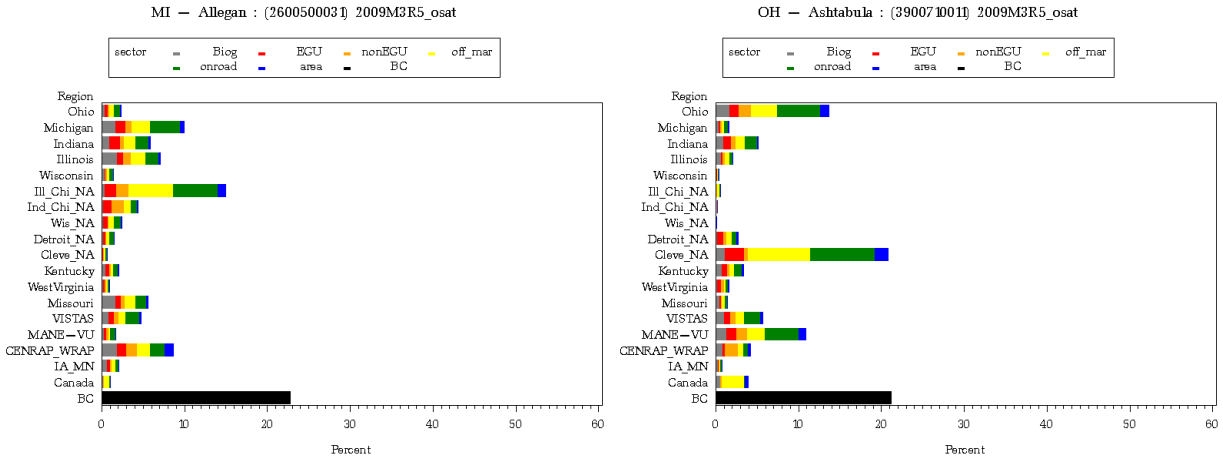


Figure 68. Source-region results for Holland (left) and Ashtabula (right) monitors – 2009 (Base M)

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year ozone concentrations. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to produce significant improvement in ozone air quality.
- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. As noted above, 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).
- Most sites are expected to meet the current 8-hour standard by the applicable attainment date, except, for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.
- Current monitoring data show significant nonattainment in these areas (e.g., peak design values on the order of 90 – 93 ppb). It is not clear whether sufficient emission reductions will occur in the next couple of years to provide for attainment.
- Attainment by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). On the other hand, if either of these conditions is not met, then attainment may be less likely.

4.3 Weight-of-Evidence Determination for $PM_{2.5}$

The WOE determination for $PM_{2.5}$ consists of the primary modeling and other supplemental analyses. A summary of this information is provided below.

Primary (Guideline) Modeling: The results of the guideline modeling are presented in Section 4.1. Key findings from this modeling include:

- Base M regional modeling shows attainment by 2009 at all sites, except Detroit, Cleveland, and Granite City, and attainment at all sites by 2012, except for Detroit and Granite City.

  The regional modeling for $PM_{2.5}$ does not reflect any air quality benefit expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$

- Base K modeling results reflect generally higher future year values, and show more sites in nonattainment in 2009 and 2012 compared to the Base M modeling. The difference in the two modeling analyses is due mostly to lower base year design values in Base M.

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for $PM_{2.5}$ should reflect a weight-of-evidence approach, with consideration of monitoring based information.

- Base M modeling also shows that the new $PM_{2.5}$ 24-hour standard will not be met at many sites, even by 2018, with existing controls.

Additional Modeling: EPA's latest regional $PM_{2.5}$ modeling was considered as corroborative information. This modeling was performed as part of the September 2006 revision to the $PM_{2.5}$ standard (USEPA, 2006). EPA applied the CMAQ model with 2001 meteorology to estimate $PM_{2.5}$ levels in 2015 and 2020 first with national rules in effect or proposed, and then with additional controls to attain the current standard (15 ug/m^3 annual/65 ug/m^3 daily). Additional analyses were performed to evaluate strategies for attaining more stringent standards in 2020 (15/35, and 14/35). Baseline (2015) $PM_{2.5}$ levels were predicted to be above the current standard in four counties in the LADCO region: Madison County, IL at 15.2 ug/m^3, Wayne County, MI at 17.4, Cuyahoga County, OH at 15.4, and Scioto County, OH at 15.6. These results are consistent with LADCO's Base K modeling for 2012/2018, which is not surprising given that EPA's modeling and LADCO's Base K modeling have a similar base year (2001 v. 2002).

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., application of thermodynamic equilibrium models) is presented in Section 3. The key findings from this modeling are that $PM_{2.5}$ mass is sensitive to reductions in sulfate, nitric acid, and ammonia concentrations. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases. Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007b). Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 69) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and biogenic sources) at $PM_{2.5}$ monitoring sites in the region.

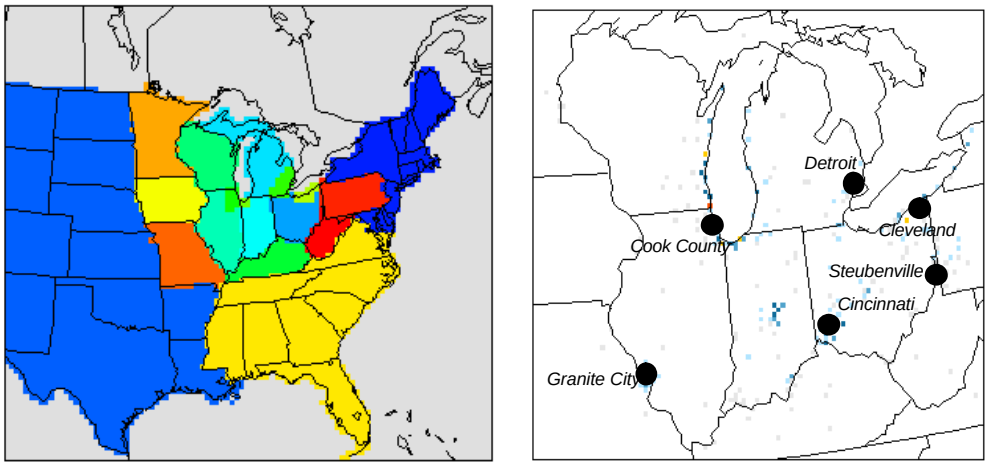


Figure 69. Source regions (left) and key monitoring sites (right) for $PM_{2.5}$ modeling analysis

Modeling results for 2012 (Base K) and 2018 (Base M) are provided in Appendix III for several key monitoring sites. For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of absolute modeled values.

The sector-level results (see, for example, Figure 70) show that EGU sulfate, non-EGU-sulfate, and area organic carbon emissions generally have the largest contributions at the key monitor locations (> 15% each). Ammonia emissions are also important contributors (> 10%). The source group contributions vary by receptor location due to emissions inventory differences.

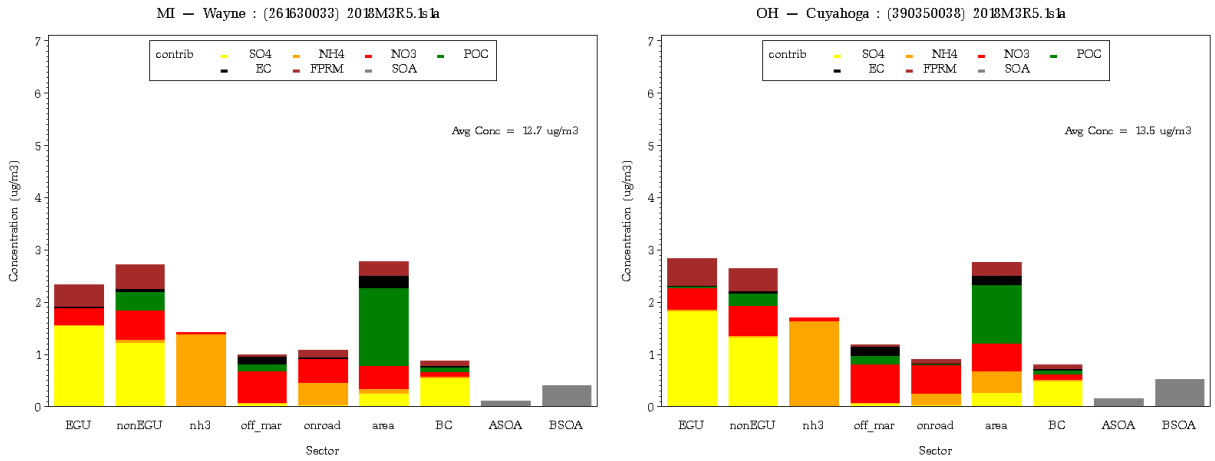


Figure 70. Source-sector results for Detroit (left) and Cleveland (right) monitors – 2018 (Base M)

The source region results (see, for example, Figure 71) show that while nearby areas generally have the highest impacts (e.g., Detroit nonattainment counties contribute 40% to high sites in southeastern Michigan, and Cleveland nonattainment counties contribute 35% to high sites in northeastern Ohio), there is an even larger regional impact (i.e., contribution from other states).

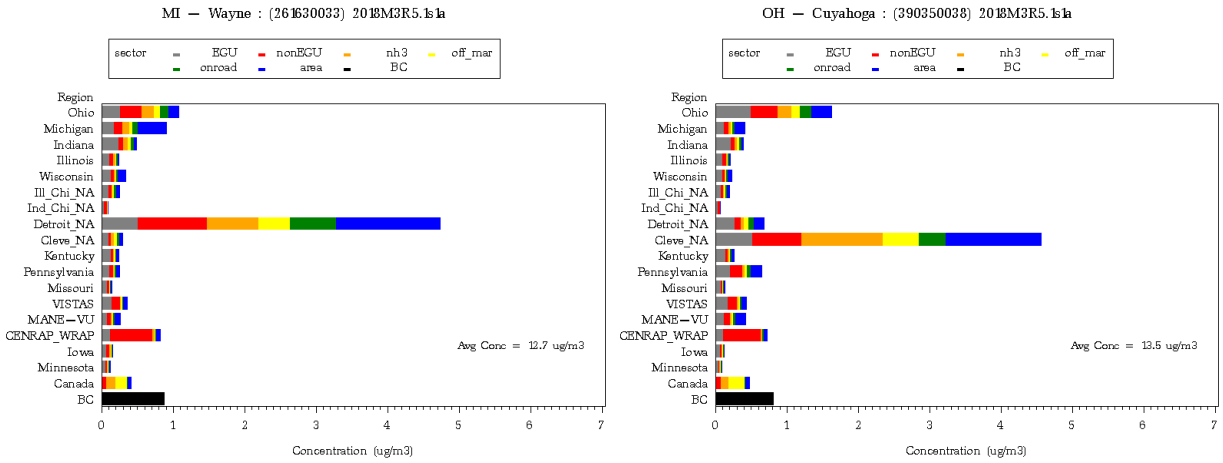


Figure 71. Source-region results for Detroit (left) and Cleveland (right) monitors – 2018 (Base M)

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year $PM_{2.5}$ concentrations. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to produce significant improvement in $PM_{2.5}$ air quality.
- The choice of the base year affects the future year model projections. It is not clear how much of this is attributable to differences in meteorology, because, as noted in Section 3, $PM_{2.5}$ concentrations are not as strongly influenced by meteorology as ozone.
- Most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.
- Current monitoring data show significant nonattainment in these areas (e.g., peak design values on the order of 16 – 17 ug/m^3). It is not clear whether sufficient emission reductions will occur in the next couple of years to provide for attainment. States are conducting local-scale analyses for Detroit, Cleveland, and Granite City, in particular, to identify appropriate additional local controls.
- Attainment by the applicable attainment date is dependent (possibly) on actual future year meteorology and (more likely) on actual future year emissions (e.g., if the emission reductions associated with the "on the books" controls are achieved, then attainment is likely). On the other hand, if either of these conditions is not met (especially, with respect to emissions), then attainment may be less likely.

Section 5. Reasonable Progress Assessment for Regional Haze

Air quality modeling and other information were used to assess the improvement in visibility that would be provided by existing ("on the books") controls and possible additional control programs. In determining reasonable progress for regional haze, Section 169A of the Clean Air Act and EPA's visibility rule requires states to consider five factors:

- costs of compliance
- time necessary for compliance
- energy and non-air quality environmental impacts of compliance
- remaining useful life of any existing source subject to such requirements
- uniform rate of visibility improvement needed to attain natural visibility conditions by 2064

The uniform rate of visibility improvement requirement can be depicted graphically in the form of a "glide path" (see Figure 72).

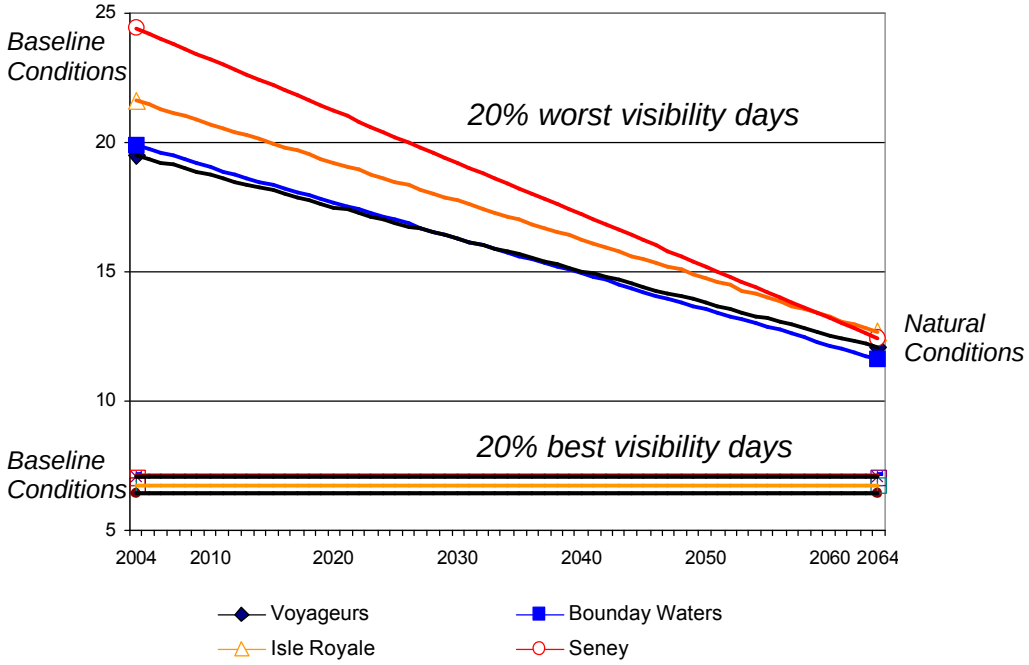


Figure 72. Visibility "glide paths" for northern Class I areas (units: deciviews)

5.1 Class I Areas Impacted

EPA's visibility rule requires a state to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." (40 CFR Part 51.308(d)) To meet this requirement, technical analyses conducted by the RPOs were consulted to obtain information on areas of influence and culpability for Class I areas in the eastern U.S. (MRPO, 2007). A summary of this information is provided in Table 1 (MRPO, 2007). The table shows that every LADCO State impacts multiple Class I areas in the eastern U.S.

Table 14. Draft List of Class I Areas Impacted by LADCO States

AREA NAME	IL	IN	MI	OH	WI
81.401 Alabama.					
Sipsey Wilderness Area	(1)	(1)			
81.404 Arkansas.					
Caney Creek Wilderness Area	(2), (4)	(2), (4)		(2), (4)	
Upper Buffalo Wilderness Area	(1),(2),(4),(5)	(2), (4)		(2), (4)	(2)
81.408 Georgia.					
Cohotta Wilderness Area					
Okefenokee Wilderness Area					
Wolf Island Wilderness Area					
81.411 Kentucky.					
Mammoth Cave NP	(1), (2), (5)	(1), (2), (5)	(1), (2)	(1), (2), (5)	
81.412 Louisiana.					
Breton Wilderness Area					
81.413 Maine.					
Acadia National Park	(3)	(3)	(3)	(3)	
Moosehorn Wilderness Area.	(3)	(3)	(3)	(3)	
81.414 Michigan.					
Isle Royale NP.	(1), (2)	(1), (2)	(1), (2)		(1), (2)
Seney Wilderness Area	(1), (2)	(1), (2)	(1), (2)	(1), (2)	(1), (2)
81.415 Minnesota.					
Boundary Waters Canoe Area Wilderness	(2)	(2)	(2)		(1), (2)
Voyageurs NP	(2)	(2)			(1), (2)
81.416 Missouri.					
Hercules-Glades Wilderness Area	(2), (4), (5)	(2), (4), (5)		(2), (4)	(2)
Mingo Wilderness Area	(2), (4), (5)	(2), (4), (5)	(2)	(2), (4)	(2)
81.419 New Hampshire.					
Great Gulf Wilderness Area	(3)	(3)	(3)	(1), (3)	
Pres. Range-Dry River Wilderness Area.					
81.42 New Jersey.					
Brigantine Wilderness Area	(3)	(3)	(1), (3)	(1), (3)	

81.422 North Carolina.					
Great Smoky Mountains NP{1}	(1)	(1)		(1)	
Joyce Kilmer-Slickrock Wilderness Area{2}					
Linville Gorge Wilderness Area.					
Shining Rock Wilderness Area.					
Swanquarter Wilderness Area					
81.426 South Carolina.					
Cape Romain Wilderness					
81.428 Tennessee.					
Great Smoky Mountains NP{1}.	(1)	(1)		(1)	
Joyce Kilmer-Slickrock Wilderness{2}					
81.431 Vermont.					
Lye Brook Wilderness	(2), (3)	(2), (3)	(2), (3)	(1), (2), (3)	
81.433 Virginia.					
James River Face Wilderness.	(2)	(2)	(2)	(2), (5)	
Shenandoah NP	(2), (3)	(1), (2), (3)	(2), (3)	(1),(2),(3),(5)	
81.435 West Virginia.					
Dolly Sods/Otter Creek Wilderness.	(2), (3)	(1), (2), (3)	(1), (2), (3)	(1),(2),(3),(5)	

Key
(1) MRPO Back Trajectory Analyses
(2) MRPO PSAT Modeling
(3) MANE-VU Contribution Assessment
(4) Missouri-Arkansas Contribution Assessment
(5) VISTAS Areas of Influence

5.2 Future Year Modeling Results

For regional haze, the calculation of future year conditions assumed:

- baseline concentrations based on 2000-2004 IMPROVE data, with updated (subsitituted) data for Mingo, Boundary Waters, Voyageurs, Isle Royale, and Seney (see Section 2.3);
- use of the new IMPROVE light extinction equation; and
- use of EPA default values for natural conditions, based on the new IMPROVE light extinction equation.

The uniform rate of visibility improvement values for the 2018 planning year were derived (for the 20% worst visibility days) based on a straight line between baseline concentration value (plotted in the year 2004 -- end year of the 5-year baseline period) and natural condition value (plotted in the year 2064 -- date for achieving natural conditions). Plots of these "glide paths" with the Base M modeling results are presented in Figure 73 for Class I areas in the eastern U.S. A tabular summary of measured baseline and modeled future year deciview values for these Class I areas are provided in Table 15 (2002 base year) and Table 16 (2005 base year)[13].

The haze results show that several Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values (in 2018), including those in northern Michigan and several in the northeastern U.S. Many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values (in 2018). As noted above, states should consider these results, along with information on the other four factors, in setting reasonable progress goals.

An assessment of the five factors was performed for LADCO and the State of Minnesota by a contractor (EC/R, 2007). Specifically, ECR examined reductions in SO2 and NOx emissions from EGUs and industrial, commercial and institutional (ICI) boilers; NOx emissions from mobile sources and reciprocating engines and turbines; and ammonia emissions from agricultural operations. The impacts of "on the books" controls were also examined to provide a frame of reference for assessing the impacts of the additional control measures.

The results of ECR's analysis of the five factors are summarized below:

> Factor 1 (Cost of Compliance): The average cost effectiveness values (in terms of $M per ton) are provided in Table 16. For comparison, cost-effectiveness estimates previously provided for "on the books" controls include:
>
> CAIR SO2: $700 - $1,200, NOx: $1,400 – $2.600 ($/T)
>
> BART SO2: $300 - $963, NOx: $248 - $1,770
>
> MACT SO2: $1,500, NOx: $7,600
>
> Most of the cost-effectiveness values for the additional controls are within the range of cost-effectiveness values for "on the books" controls.

[13] Model results reflect the grid cell where the IMPROVE monitor is located.

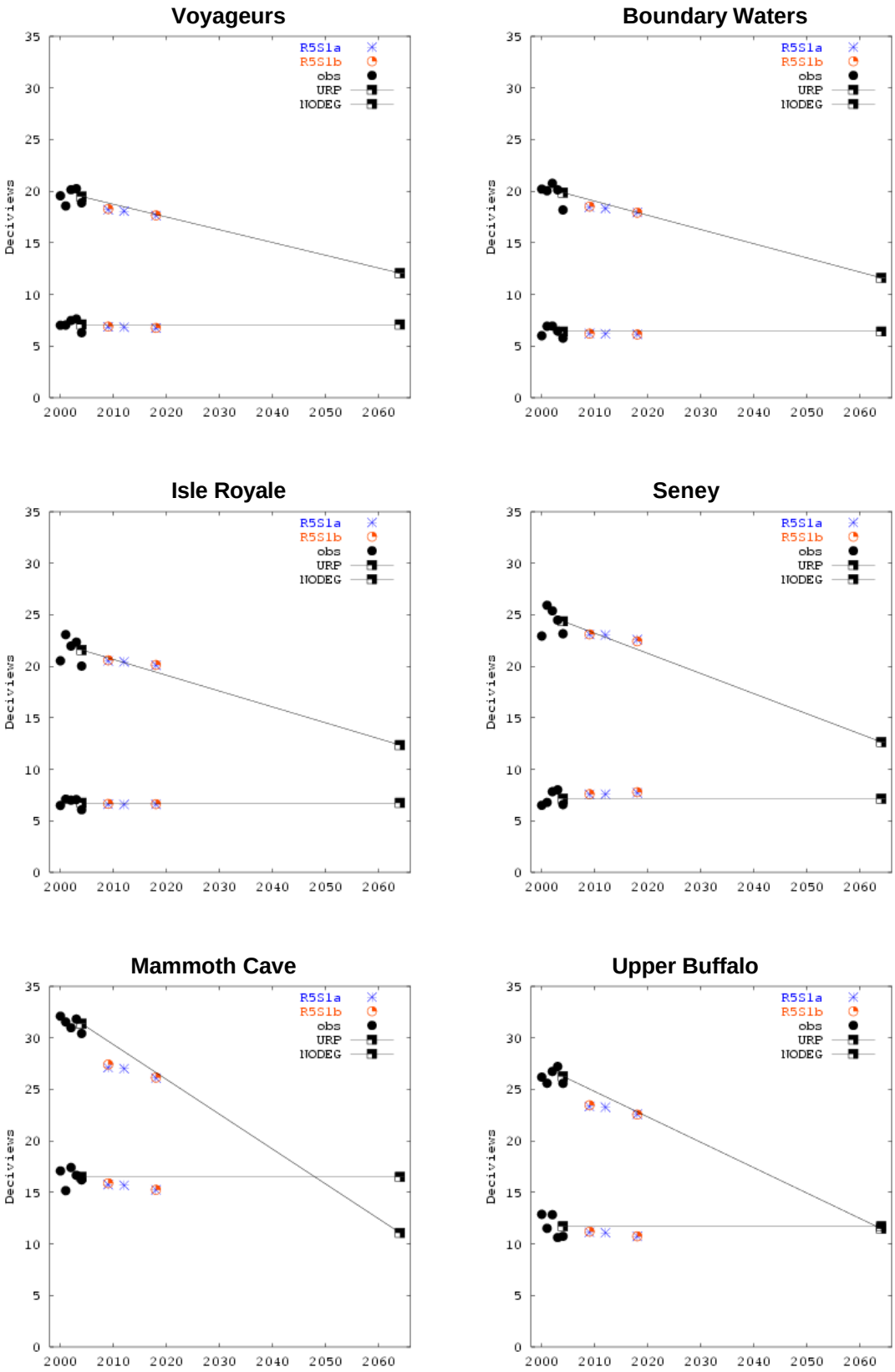


Figure 73. Visibility modeling results for Class I areas in eastern U.S.

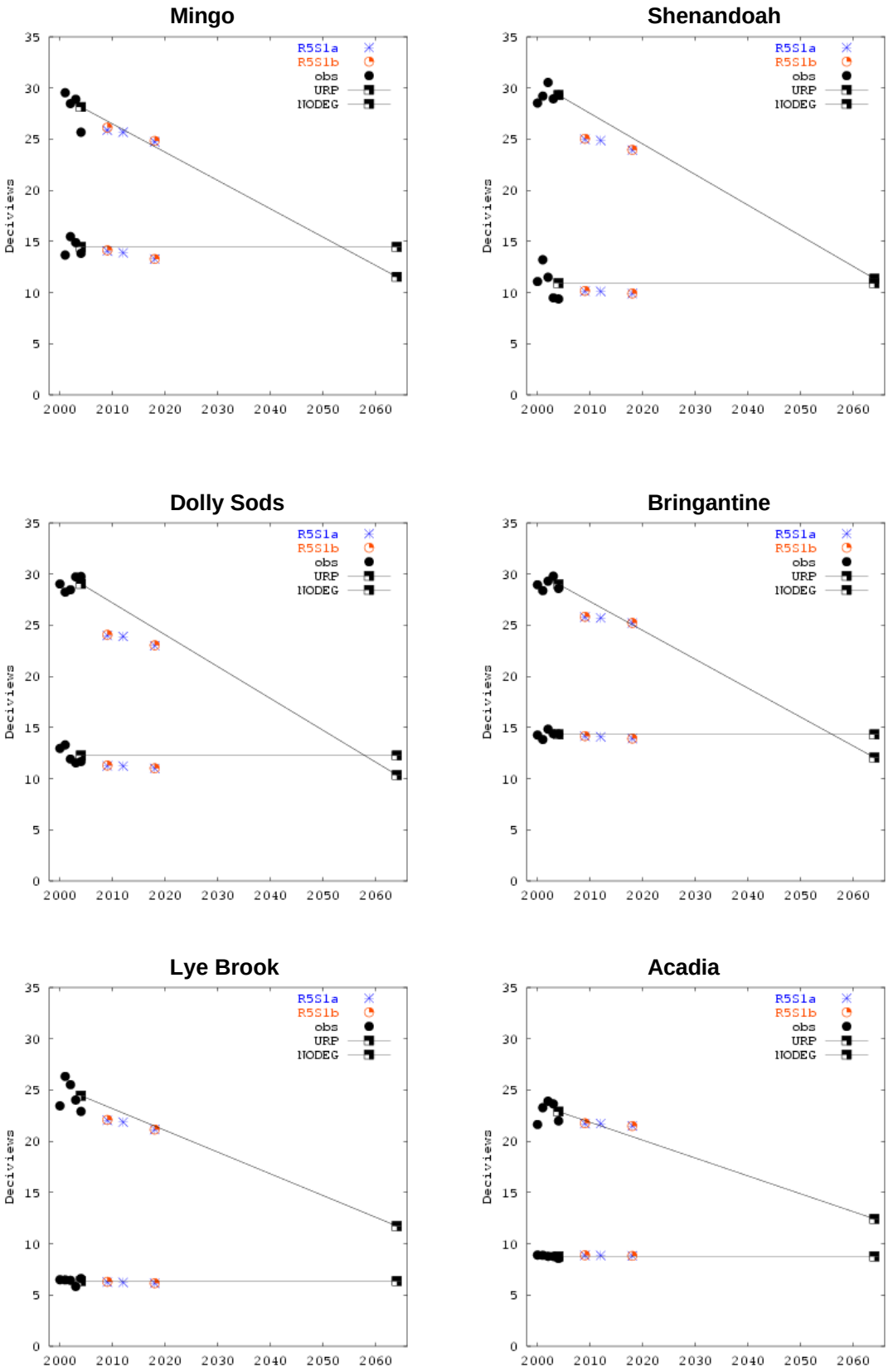


Figure 73 (cont.) Visibility modeling results for Class I areas in eastern U.S.

Table 15. Haze Results - Round 4 (Based on 2000-2004)							
Worst 20%		**2018**	**2009**	**2012**	**2018**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**EGU2 (5-state region)**	**EGU2 (12-state region)**
BOWA1	19.86	17.70	19.05	19.01	**18.94**	**18.40**	17.72
VOYA2	19.48	17.56	19.14	19.19	**19.18**	**18.94**	**18.38**
SENE1	24.38	21.35	22.98	22.71	**22.38**	21.26	20.63
ISLE1	21.59	19.21	20.46	20.28	**20.04**	19.09	18.64
HEGL1	26.75	22.76	24.73	24.34	**23.85**	**23.01**	22.04
MING1	28.15	24.08	25.18	24.67	24.01	22.53	21.45
CACR1	26.36	22.55	24.01	23.55	**22.99**	22.43	21.57
UPBU1	26.27	22.47	24.02	23.58	**23.06**	22.31	21.38
MACA1	31.37	26.14	28.06	27.03	25.52	24.27	22.57
DOSO1	29.04	24.23	24.86	23.59	22.42	21.60	20.15
SHEN1	29.31	24.67	24.06	22.79	21.57	20.43	19.42
JARI1	29.12	24.48	24.81	23.79	22.42	21.59	20.88
BRIG1	29.01	24.68	25.87	25.25	24.39	23.91	23.45
LYBR1	24.45	21.16	21.80	21.32	20.69	20.18	19.79
Best 20%		**2018**	**2009**	**2012**	**2018**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**EGU2 (5-state region)**	**EGU2 (12-state region)**
BOWA1	6.42	6.42	6.71	6.73	6.87	6.83	6.81
VOYA2	7.09	7.09	7.21	7.25	7.34	7.31	7.26
SENE1	7.14	7.14	7.19	7.19	7.23	7.06	6.91
ISLE1	6.75	6.75	6.57	6.51	6.47	6.20	6.06
HEGL1	12.84	12.84	12.61	12.62	12.61	12.43	12.02
MING1	14.46	14.46	13.96	13.93	13.94	13.74	13.33
CACR1	11.24	11.24	10.91	10.92	10.90	10.75	10.42
UPBU1	11.71	11.71	11.47	11.46	11.42	11.28	11.01
MACA1	16.51	16.51	16.06	15.91	15.54	15.18	14.75
DOSO1	12.28	12.28	11.72	11.45	11.19	10.93	10.67
SHEN1	10.93	10.93	9.73	9.53	9.17	9.05	8.90
JARI1	14.21	14.21	13.56	13.33	12.97	12.65	12.46
BRIG1	14.33	14.33	13.74	13.69	13.47	13.32	13.21
LYBR1	6.36	6.36	6.12	6.05	5.96	5.88	5.82

Table 16. Haze Results - Round 5.1 (Based on 2000-2004)						
Worst 20%		**2018**	**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	19.86	17.94	18.45	18.33	17.94	17.92
VOYA2	19.48	17.75	18.20	18.07	17.63	17.66
SENE1	24.38	21.64	23.10	23.04	**22.59**	**22.42**
ISLE1	21.59	19.43	20.52	20.43	**20.09**	**20.13**
ISLE9	21.59	19.43	20.33	20.22	**19.84**	**19.82**
HEGL1	26.75	23.13	24.72	24.69	**24.22**	**24.17**
MING1	28.15	24.27	25.88	25.68	**24.74**	**24.83**
CACR1	26.36	22.91	23.39	23.29	22.44	22.40
UPBU1	26.27	22.82	23.34	23.27	22.59	22.55
MACA1	31.37	26.64	27.11	27.01	26.10	26.15
DOSO1	29.05	24.69	24.00	23.90	23.00	23.04
SHEN1	29.31	25.12	24.99	24.87	23.92	23.95
JARI1	29.12	24.91	25.17	25.01	24.06	24.12
BRIG1	29.01	25.05	25.79	25.72	**25.21**	**25.22**
LYBR1	24.45	21.48	22.04	21.86	21.14	21.14
ACAD1	22.89	20.45	21.72	21.72	**21.49**	**21.49**
Best 20%		**2018**	**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**Max**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	6.42	6.42	6.21	6.19	6.14	6.12
VOYA2	7.09	7.09	6.86	6.83	6.75	6.76
SENE1	7.14	7.14	7.57	7.58	7.71	7.78
ISLE1	6.75	6.75	6.62	6.59	6.60	6.62
ISLE9	6.75	6.75	6.56	6.55	6.52	6.50
HEGL1	12.84	12.84	12.51	12.32	11.66	11.64
MING1	14.46	14.46	14.07	13.89	13.28	13.29
CACR1	11.24	11.24	10.88	10.85	10.52	10.52
UPBU1	11.71	11.71	11.13	11.08	10.73	10.74
MACA1	16.51	16.51	15.76	15.69	15.25	15.25
DOSO1	12.28	12.28	11.25	11.23	11.00	11.01
SHEN1	10.93	10.93	10.13	10.11	9.91	9.91
JARI1	14.21	14.21	13.38	13.38	13.14	13.14
BRIG1	14.33	14.33	14.15	14.08	13.92	13.92
LYBR1	6.37	6.37	6.25	6.23	6.14	6.15
ACAD1	8.78	8.78	8.86	8.86	8.82	8.82

Table 17. Estimated Cost Effectiveness for Potential Control Measures

			Average Cost effectiveness ($/ton)		
Emission category	Control strategy	Region	SO2	NOX	NH3
EGU	EGU1	3-State	1,540	2,037	
		9-State	1,743	1,782	
	EGU2	3-State	1,775	3,016	
		9-State	1,952	2,984	
ICI boilers	ICI1	3-State	2,992	2,537	
		9-State	2,275	1,899	
	ICI Workgroup	3-State	2,731	3,814	
		9-State	2,743	2,311	
Reciprocating engines and turbines	Reciprocating engines emitting 100 tons/year or more	3-State		538	
		9-State		506	
	Turbines emitting 100 tons/year or more	3-State		754	
		9-State		754	
	Reciprocating engines emitting 10 tons/year or more	3-State		1,286	
		9-State		1,023	
	Turbines emitting 10 tons/year or more	3-State		800	
		9-State		819	
Agricultural sources	10% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
	15% reduction	3-State			31 - 2,700
		9-State			31 - 2,700
Mobile sources	Low-NOX Reflash	3-State		241	
		9-State		241	
	MCDI	3-State		10,697	
		9-State		2,408	
	Anti-Idling	3-State		(430) - 1,700	
		9-State		(430) - 1,700	
	Cetane Additive Program	3-State		4,119	
		9-State		4,119	
Cement Plants	Process Modification	Michigan		-	
	Conversion to dry kiln	Michigan		9,848	
	LoTox™	Michigan		1,399	
Glass Manufacturing	LNB	Wisconsin		1,041	
	Oxy-firing	Wisconsin		2,833	
	Electric boost	Wisconsin		3,426	
	SCR	Wisconsin		1,054	
	SNCR	Wisconsin		1,094	
Lime Manufacturing	Mid-kiln firing	Wisconsin		688	
	LNB	Wisconsin		837	
	SNCR	Wisconsin		1,210	
	SCR	Wisconsin		5,037	
	FGD	Wisconsin		128 - 4,828	
Oil Refinery	LNB	Wisconsin		3,288	
	SNCR	Wisconsin		4,260	
	SCR	Wisconsin		17,997	
	LNB+FGR	Wisconsin		4,768	
	ULNB	Wisconsin		2,242	
	FGD	Wisconsin		1,078	

Factor 2 (Time Necessary for Compliance): All of the control measures can be implemented by 2018. Thus, this factor can be easily addressed.

Factor 3 (Energy and Non-Air Quality Environmental Impacts): The energy and other environmental impacts are believed to be manageable. For example, the increased energy demand from add-on control equipment is less than 1% of the total electricity and steam production in the region, and solid waste disposal and wastewater treatment costs are less than 5% of the total operating costs of the pollution control equipment. It should also be noted that the SO2 and NOx controls would have beneficial environmental impacts (e.g., reduced acid deposition and nitrogen deposition).

Factor 4 (Remaining Useful Life): The additional control measures are intended to be market-based strategies applied over a broad geographic region. It is not expected that the control requirements will be applied to units that will be retired prior to the amortization period for the control equipment. Thus, this factor can be easily addressed.

Factor 5 (Visibility Impacts): The estimated incremental improvement in 2018 visibility levels for the additional measures is shown in Figure 74, along with the cost-effectiveness expressed in $M per deciview improvement). These results show that although EGU and ICI boiler controls have higher cost-per-deciview values (compared to some of the other measures), their visibility impacts are larger.

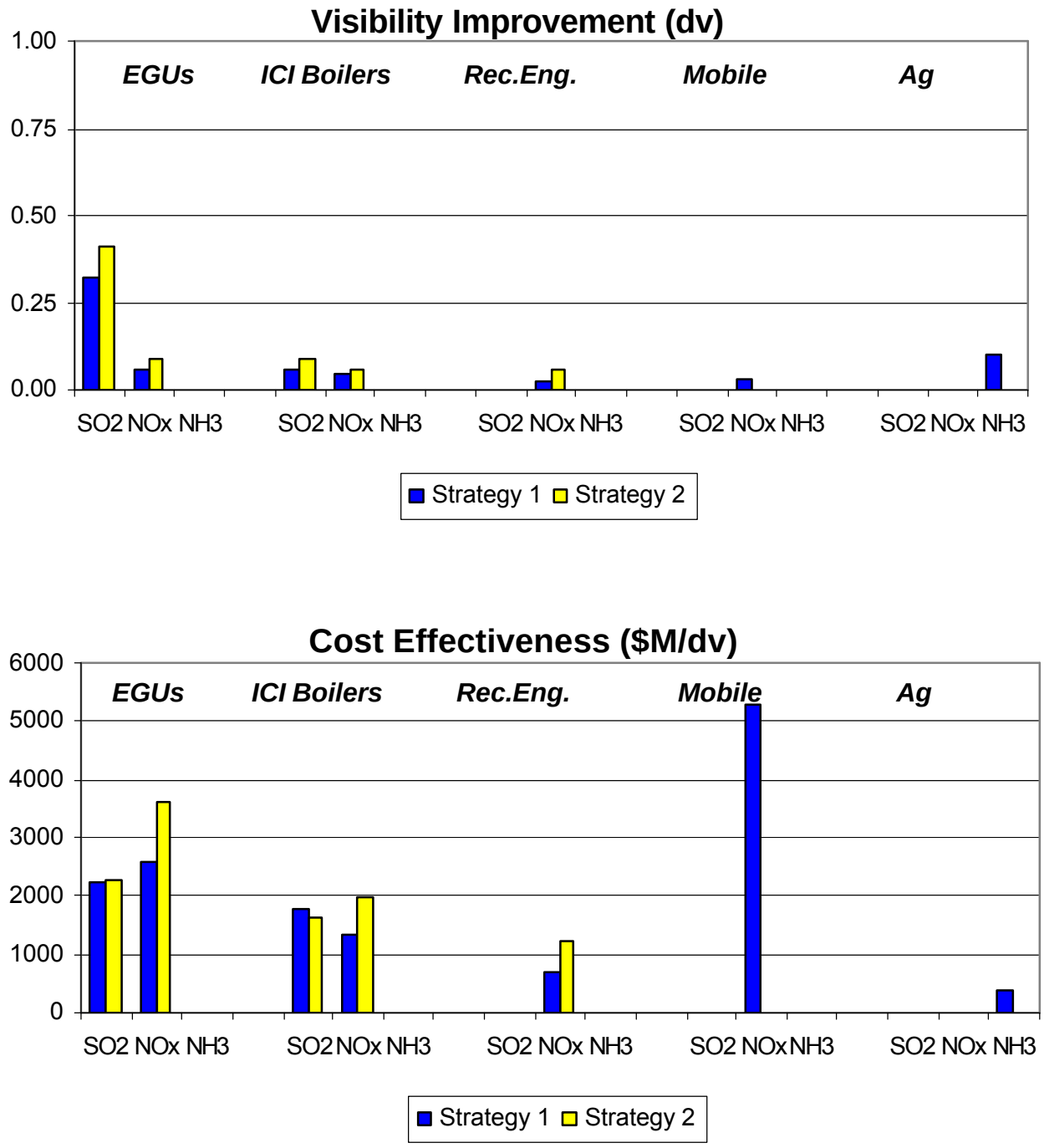


Figure 74. Results of ECR analysis of reasonable progress factors – visibility improvement (Factor 5) is on top, and cost effectiveness (Factor 1) is on bottom

5.3 Weight-of-Evidence Determination for Haze

The WOE determination for haze consists of the primary modeling and other supplemental analyses. A summary of this information is provided below.

Primary (Guideline) Modeling: The results of the guideline modeling are presented in Section 4.1. Key findings from this modeling include:

- Base M modeling results show that the northern Minnesota Class I areas are close to the glide path, whereas the northern Michigan Class I areas are above the glide path in 2018. Other sites in the eastern U.S. are close to (or below) the glide path, except for Mingo (MO), Brigantine (NJ), and Acadia (ME).

- Base K modeling results show that the northern Minnesota and northern Michigan Class I areas are above the glide path in 2018. Other sites in the eastern U.S. are close to (or below) the glide path.

- The difference in the two modeling analyses is due mostly to differences in future year emission projections, especially for EGUs (e.g., use of IPM2.1.9 v. IPM3.0).

- Base K and Base M modeling analyses are considered "SIP quality", so the attainment demonstration for haze should reflect a weight-of-evidence approach, with consideration of monitoring based information.

Additional Modeling: Two additional modeling analyses were considered: (1) the primary modeling redone with different baseline values, and (2) modeling by the State of Minnesota which looked at different receptor locations in the northern Class I areas (MPCA, 2008). Each of these analyses is described below.

First, the primary modeling analysis (Base M) was revised using an alternative baseline value. Specifically, the data for the period 2000-2005 were used to calculate the baseline, given that the Base M modeling reflects a 2005 base year. The results of this alternative analysis (see Table 18) are generally consistent with the primary modeling (see Table 16).

Second, Minnesota's modeling reflects a 2002 base year and much of the data developed by LADCO for its modeling. (Note, Minnesota conducted modeling for LADCO's domain at 36 km, and for a statewide domain at 12 km.) The purpose of the 12 km modeling was to address local scale impacts on the northern Class I areas at several locations, not just the location of the IMPROVE monitor. Results for the Boundary Waters on the 20% worst days range from 18.3 – 19.0 dv, with an average value of 18.7 dv, which is consistent with Minnesota's 36 km modeling results at the IMPROVE monitor. This variability in visibility levels should be kept in mind when reviewing the values presented in Tables 15, 16, and 18, which reflect results at the IMPROVE monitor locations.

Table 18. Haze Results - Round 5.1 (Based on 2000-2005)						
Worst 20%			**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	20.10	18.12	18.63	18.51	18.12	18.09
VOYA2	19.62	17.86	18.27	18.15	17.70	17.72
SENE1	24.77	21.94	23.44	23.39	**22.94**	**22.77**
ISLE1	21.95	19.71	20.84	20.76	**20.41**	**20.44**
ISLE9	21.95	19.71	20.65	20.55	**20.15**	**20.13**
HEGL1	27.45	23.67	25.30	25.27	**24.79**	**24.73**
MING1	28.92	24.86	25.88	25.68	24.74	24.83
CACR1	27.05	23.44	23.88	23.78	22.92	22.86
UPBU1	26.97	23.36	23.92	23.85	23.14	23.09
MACA1	31.76	26.93	27.42	27.32	26.39	26.44
DOSO1	29.36	24.92	24.20	24.11	23.19	23.23
SHEN1	29.45	25.23	25.06	24.94	23.98	24.01
JARI1	29.40	25.13	25.32	25.17	24.22	24.28
BRIG1	29.12	25.14	25.84	25.77	**25.26**	**25.26**
LYBR1	24.71	21.69	22.22	22.06	21.36	21.36
ACAD1	22.91	20.47	21.72	21.72	**21.49**	**21.49**
Best 20%			**2009**	**2012**	**2018**	**2018**
Site	**Baseline**	**URP**	**OTB**	**OTB**	**OTB**	**OTB+Will DO**
BOWA1	6.40	6.40	6.20	6.17	6.13	6.10
VOYA2	7.05	7.05	6.82	6.78	6.71	6.71
SENE1	7.20	7.20	7.60	7.61	7.73	7.80
ISLE1	6.80	6.80	6.67	6.64	6.65	6.66
ISLE9	6.80	6.80	6.62	6.61	6.57	6.55
HEGL1	13.04	13.04	12.71	12.51	11.85	11.82
MING1	14.68	14.68	14.07	13.89	13.28	13.29
CACR1	11.62	11.62	11.24	11.20	10.86	10.86
UPBU1	11.99	11.99	11.41	11.36	11.01	11.02
MACA1	16.64	16.64	15.88	15.82	15.37	15.38
DOSO1	12.24	12.24	11.21	11.19	10.96	10.97
SHEN1	10.85	10.85	10.04	10.02	9.82	9.83
JARI1	14.35	14.35	13.51	13.51	13.27	13.27
BRIG1	14.36	14.36	14.17	14.10	13.94	13.94
LYBR1	6.21	6.21	6.11	6.09	6.01	6.01
ACAD1	8.57	8.57	8.67	8.66	8.62	8.62

Observational Models and Diagnostic Analyses: The observation-based modeling (i.e., application of thermodynamic equilibrium models) is presented in Section 3. The key findings from this modeling are that $PM_{2.5}$ mass is sensitive to reductions in sulfate, nitric acid, and ammonia concentrations. Even though sulfate reductions cause more ammonia to be available to form ammonium nitrate (PM-nitrate increases slightly when sulfate is reduced), this increase is generally offset by the sulfate reductions, such that $PM_{2.5}$ mass decreases and visibility improves. Under conditions with lower sulfate levels (i.e., proxy of future year conditions), $PM_{2.5}$ is more sensitive to reductions in nitric acid compared to reductions in ammonia.

As discussed in Section 2, thermodynamic equilibrium modeling based on data collected at Seney indicates that $PM_{2.5}$ there is most sensitive to reductions in sulfate, but also responsive to reductions in nitric acid (Blanchard, 2004). An analysis using data from the Midwest ammonia monitoring network for a site in Minnesota (i.e., Great River Bluffs, which is the closest ammonia monitoring site to the northern Class I areas) suggested that reductions in sulfate, nitric acid, and ammonia concentrations will lower $PM_{2.5}$ concentrations and improve visibility levels in the northern Class I areas.

Trajectory analyses for the 20% worst visibility days for the four northern Class I areas are provided in Figure 75. (Note, this figure is similar to Figure 34, but the trajectory results for each Class I area are displayed separately here.) The orange areas are where the air is most likely to come from, and the green areas are where the air is least likely to come from. Darker shading represents higher frequency. As can be seen, bad air days are generally associated with transport from regions located to the south, and good air days with transport from Canada.

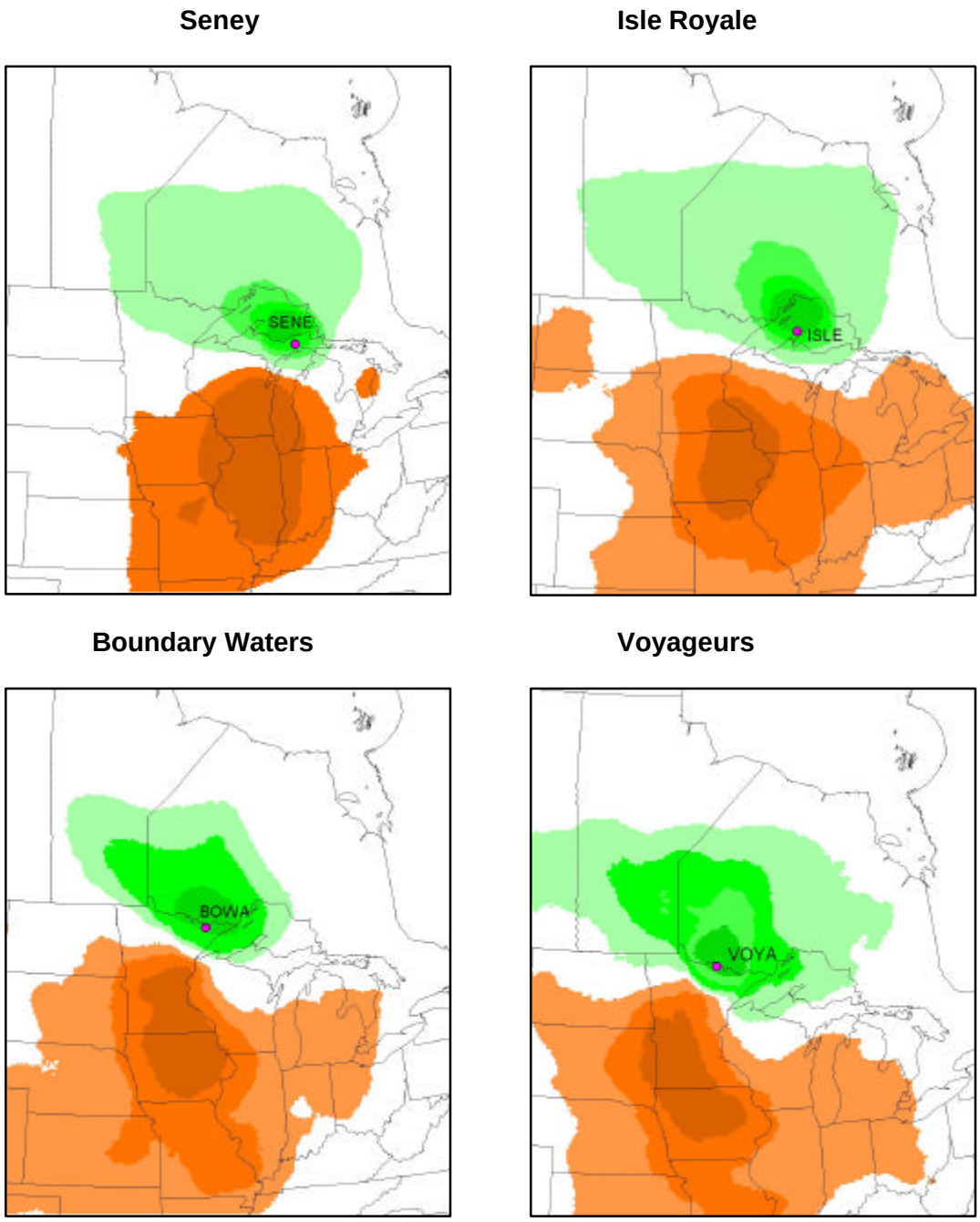


Figure 75. Trajectory analysis results for northern Class I areas on 20% worst visibility days

The primary diagnostic analysis is source apportionment modeling with CAMx to provide more quantitative information on source region (and source sector) impacts (Baker, 2007b). Specifically, the CAMx model was applied to provide source contribution information. Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 76) and 6 source se ctors (EGU point, non-EGU point, on-road, off-road, area, and ammonia sources) at visibility/haze monitoring sites in the eastern U.S.

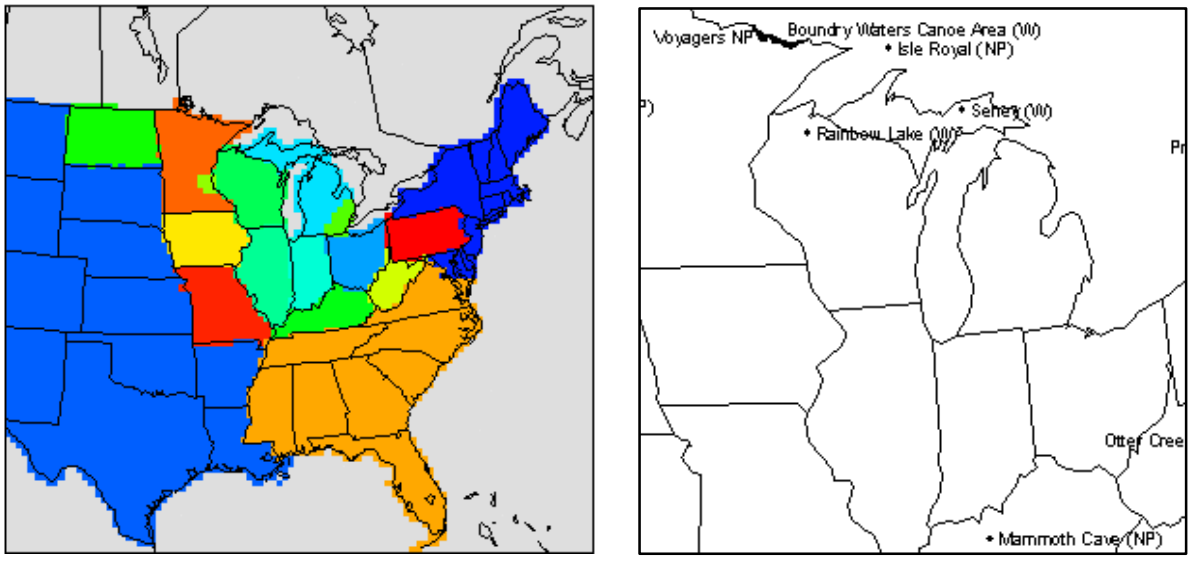


Figure 76. Source regions (left) and key monitoring sites (right) for haze modeling analysis

Modeling results for 2018 (Base K and Base M) are provided in Appendix IV for several key monitoring sites (Class I areas). For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of absolute modeled values.

The sector-level results (see, for example, Figure 77) show that EGU sulfate, non-EGU-sulfate, and ammonia emissions generally have the largest contributions at the key monitor locations. The source group contributions vary by receptor location due to emissions inventory differences.

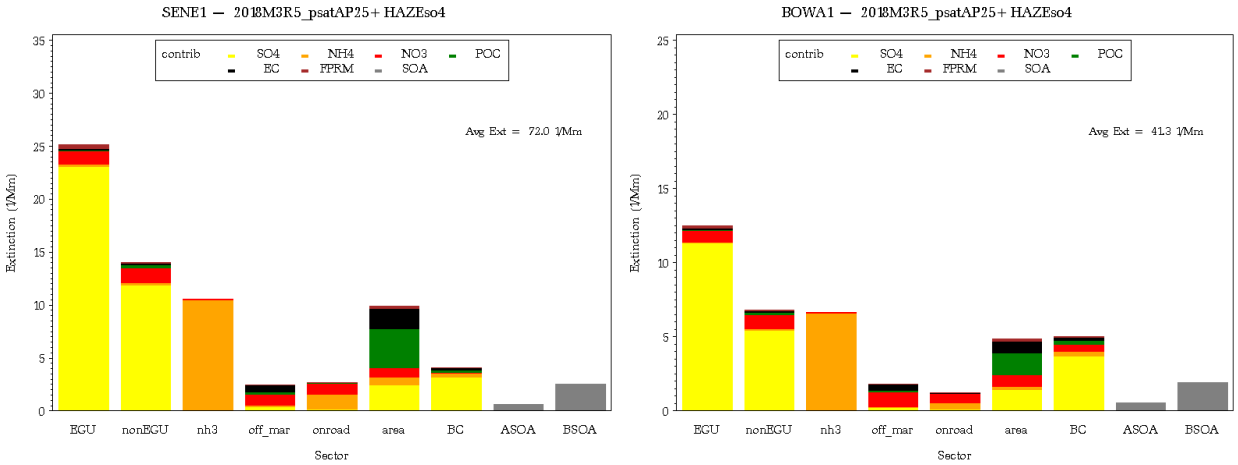


Figure 77. Source-sector results for Seney (left) and Boundary Waters (right) – 2018 (Base M)

The source region results (see, for example, Figure 78) show that emissions from a number of nearby states contribute to regional haze levels.

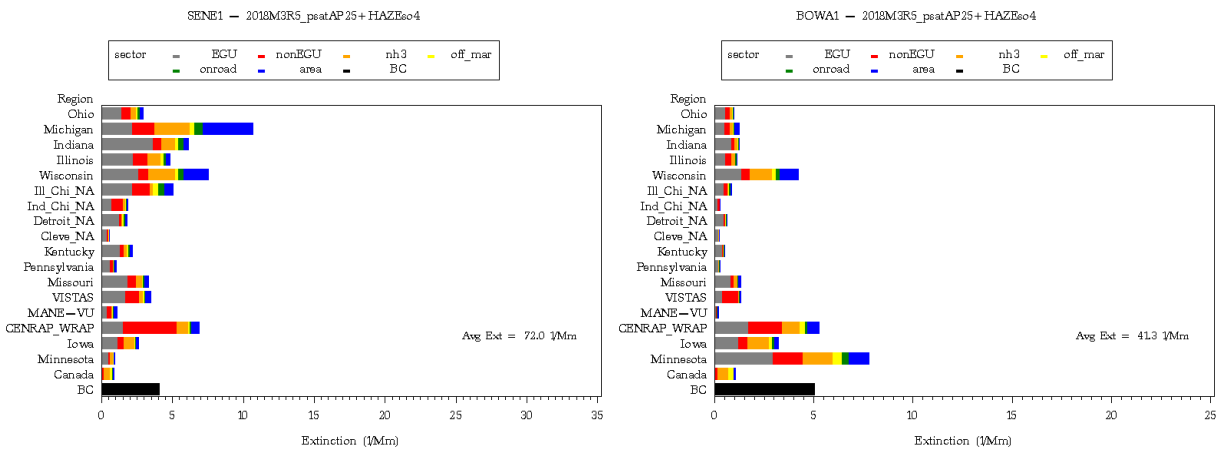


Figure 78. Source-region results for Seney (left) and Boundary Waters (right) – 2018 (Base M)

Table 19 provides a summary of the estimated state-level culpabilities based on the LADCO back trajectory analyses and the PSAT analyses for 2018.

Summary: Air quality modeling and other supplemental analyses were performed to estimate future year visibility levels. Based on this information, the following general conclusions can be made:

- Existing ("on the books") controls are expected to improve visibility levels in the northern Class I areas.
- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018, including those in northern Michigan and some in the northeastern U.S.
- Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018.

Table 19. State Culpabilities Based on PSAT Modeling and Trajectory Analyses

	Boundary Waters						Seney			
	LADCO - Round 4 PSAT	**LADCO - Round 5 PSAT**	**MPCA-PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**		**LADCO - Round 4 PSAT**	**LADCO - Round 5 PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**
Michigan	3.4%	4.8%	3.0%	1.9%	0.7%		13.8%	18.1%		14.7%
Minnesota	30.5%	23.5%	28.0%	30.6%	37.6%		4.8%	1.6%		3.8%
Wisconsin	10.4%	10.9%	10.0%	6.4%	10.6%		12.6%	10.9%		8.4%
Illinois	5.2%	5.1%	6.0%	3.5%	2.7%		13.0%	14.3%		7.4%
Indiana	2.9%	3.9%	3.0%	1.8%	1.2%		9.6%	11.6%		2.2%
Iowa	7.6%	8.3%	8.0%	2.5%	7.4%		6.2%	3.8%		5.7%
Missouri	5.2%	3.4%	6.0%	2.1%	3.3%		6.5%	4.8%		3.2%
N. Dakota	5.7%	1.1%	6.0%	4.6%	5.9%		1.5%	0.1%		0.6%
Canada	1.9%	2.7%	3.0%	12.5%	15.1%		2.1%	1.2%		11.1%
CENRAP-WRAP	10.9%	13.5%		4.2%	10.1%		13.1%	10.0%		7.0%
	83.6%	**77.2%**	**73.0%**	**70.2%**	**94.6%**		**83.3%**	**76.4%**		**64.1%**
	Voyageurs						**Isle Royale**			
	LADCO - Round 4 PSAT	**LADCO - Round 5 PSAT**	**MPCA-PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**		**LADCO - Round 4 PSAT**	**LADCO - Round 5 PSAT**	**CENRAP - PSAT**	**LADCO - Traj. Analysis**
Michigan	2.0%	4.9%	2.0%	1.0%	1.6%		12.7%	13.4%		
Minnesota	35.0%	20.2%	31.0%	31.5%	36.9%		14.1%	9.5%		
Wisconsin	6.3%	7.9%	6.0%	3.7%	9.7%		16.3%	14.7%		
Illinois	3.0%	7.1%	3.0%	1.8%	1.2%		7.0%	8.7%		
Indiana	1.6%	4.6%	2.0%	0.8%			5.6%	5.2%		
Iowa	7.4%	7.1%	7.0%	2.4%	10.2%		6.9%	8.3%		
Missouri	4.3%	4.0%	4.0%	1.6%	0.3%		3.9%	4.6%		
N. Dakota	10.3%	1.7%	13.0%	6.1%	7.1%		3.6%	0.3%		
Canada	2.7%	3.3%	5.0%	17.2%	13.3%		2.2%	1.7%		
CENRAP-WRAP	10.2%	13.7%		6.1%	16.5%		12.5%	12.6%		
	82.7%	**74.5%**	**73.0%**	**72.2%**	**96.8%**		**84.9%**	**79.0%**		

Section 6. Summary

To support the development of SIPs for ozone, $PM_{2.5}$, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin, technical analyses were conducted by LADCO, its member states, and various contractors. The analyses include preparation of regional emissions inventories and meteorological modeling data for two base years, evaluation and application of regional chemical transport models, and review of ambient monitoring data.

Analyses of monitoring data were conducted to produce a conceptual model, which is a qualitative summary of the physical, chemical, and meteorological processes that control the formation and distribution of pollutants in a given region. Key findings of the analyses include:

Ozone

- Current monitoring data show about 20 sites in violation of the 8-hour ozone standard of 85 ppb. Historical ozone data show a steady downward trend over the past 15 years, especially since 2001-2003, due likely to federal and state emission control programs.

- Ozone concentrations are strongly influenced by meteorological conditions, with more high ozone days and higher ozone levels during summers with above normal temperatures.

- Inter- and intra-regional transport of ozone and ozone precursors affects many portions of the five states, and is the principal cause of nonattainment in some areas far from population or industrial centers

$PM_{2.5}$

- Current monitoring data show 30 sites in violation of the annual $PM_{2.5}$ standard of 15 ug/m^3. Nonattainment sites are characterized by an elevated regional background (about 12 – 14 ug/m^3) and a significant local (urban) increment (about 2 – 3 ug/m^3). Historical $PM_{2.5}$ data show a slight downward trend since deployment of the $PM_{2.5}$ monitoring network in 1999.

- $PM_{2.5}$ concentrations are also influenced by meteorology, but the relationship is more complex and less well understood compared to ozone.

- On an annual average basis, $PM_{2.5}$ chemical composition consists of mostly sulfate, nitrate, and organic carbon in similar proportions.

Haze

- Current monitoring data show visibility levels in the Class I areas in northern Michigan are on the order of 22 – 24 deciviews. The goal of EPA's visibility program is to achieve natural conditions, which is on the order of 12 deciviews for these Class I areas, by the year 2064.

- Visibility impairment is dominated by sulfate and nitrate.

Air quality models were applied to support the regional planning efforts. Two base years were used in the modeling analyses: 2002 and 2005. EPA's modeling guidance recommends using

2002 as the baseline inventory year, but also allows for use of an alternative baseline inventory year, especially a more recent year. Initially, LADCO conducted modeling with a 2002 base year (i.e., Base K modeling, which was completed in 2006). A decision was subsequently made to conduct modeling with a 2005 base year (i.e., Base M, which was completed in 2007). Statistical analyses showed that 2002 and 2005 both had above normal ozone-conducive conditions, although 2002 was more severe compared to 2005. Examination of multiple base years provides for a more complete technical assessment. Both sets of model runs are discussed in this document.

Basecase modeling was conducted to evaluate model performance (i.e., assess the model's ability to reproduce the observed concentrations). This exercise was intended to assess whether, and to degree, confidence in the model is warranted (and to assess whether model improvements are necessary). Model performance for ozone and $PM_{2.5}$ was generally acceptable and can be characterized as follows:

Ozone

- Good agreement between modeled and monitored concentration for higher concentration levels (> 60 ppb) – i.e., bias within 30%

- Regional modeled concentrations appear to be underestimated in the 2002 base year, but show better agreement (with monitored data) in the 2005 base year due to model and inventory improvements.

- Day-to-day and hour-to-hour variation in and spatial patterns of modeled concentrations are consistent with monitored data

- Model accurately simulates the change in monitored ozone concentrations due to reductions in precursor emissions.

$PM_{2.5}$

- Good agreement in the magnitude of fine particle mass, but some species are overestimated and some are underestimated
    - Sulfates: good agreement in the 2002 base year, but underestimated in the summer in the 2005 base year due probably to meteorological factors
    - Nitrates: slightly overestimated in the winter in the 2002 base year, but good agreement in the 2005 base year as a result of model and inventory improvements
    - Organic Carbon: grossly underestimated in the 2002 and 2005 base years due likely to missing primary organic carbon emissions

- Temporal variation and spatial patterns of modeled concentrations are consistent with monitored data

Future year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment. Traditionally, attainment demonstrations involved a "bright line" test in which a single modeled value (based on EPA guidance) was compared to the ambient standard. To provide a more robust assessment of expected future year air quality, other information was considered. Furthermore, according to EPA's modeling guidance, if the future year modeled values are "close" to the

standard (i.e., 82 – 87 ppb for ozone and 14.5 – 15.5 ug/m^3 for $PM_{2.5}$), then the results of the primary modeling should be reviewed along with the supplemental information in a "weight of evidence" (WOE) assessment of whether each area is likely to achieve timely attainment. Key findings of the WOE determination include:

- Existing controls are expected to produce significant improvement in ozone and $PM_{2.5}$ concentrations and visibility levels.

- The choice of the base year affects the future year model projections. A key difference between the base years of 2002 and 2005 is meteorology. 2002 was more ozone conducive than 2005. The choice of which base year to use as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).

- Most sites are expected to meet the current 8-hour standard by the applicable attainment date, except for sites in western Michigan and, possibly, in eastern Wisconsin and northeastern Ohio.

- Most sites are expected to meet the current $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City.

  The regional modeling for $PM_{2.5}$ does not reflect air quality benefits expected from local controls. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$.

- These findings of residual nonattainment for ozone and $PM_{2.5}$ are supported by current (2005 – 2007) monitoring data which show significant nonattainment in the region (e.g., peak ozone design values on the order of 90 – 93 ppb, and peak $PM_{2.5}$ design values on the order of 16 - 17 ug/m^3). It is unlikely that sufficient emission reductions will occur in the next few of years to provide for attainment at all sites.

- Attainment at most sites by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are consistent with [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). If either of these conditions is not met, then attainment may be less likely.

- The new $PM_{2.5}$ 24-hour standard and the new lower ozone standard will not be met at several sites, even by 2018, with existing controls.

- Visibility levels in a few Class I areas in the eastern U.S. are expected to be greater than (less improved than) the uniform rate of visibility improvement values in 2018 based on existing controls, including those in northern Michigan and some in the northeastern U.S. Visibility levels in many other Class I areas in the eastern U.S. are expected to be less than (more improved than) the uniform rate of visibility improvement values in 2018.

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http://vista.cira.colostate.edu/views/

APPENDIX I

Ozone and $PM_{2.5}$ Modeling Results

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2008 - OTB		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	
Lake Michigan Area														***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.968	**82.0**	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.966	77.6	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.963	79.6	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.960	80.0	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.957	81.3	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.959	**84.4**	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.954	78.9	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.956	**84.8**	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.971	75.4	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.971	77.0	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.964	74.2	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.967	75.7	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.951	**85.6**	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.950	77.9	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.951	80.8	Muskegon
Indianapolis Area														***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.944	78.0	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.948	73.9	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.951	74.8	Fort B. Harrison
Detroit Area														***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.962	**82.7**	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.982	**82.5**	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.956	79.0	Port Huron
Cleveland Area														***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.954	**84.9**	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.954	75.7	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.959	**82.8**	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.948	79.3	
Cincinnati Area														***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.945	77.8	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.965	81.7	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.954	**83.6**	Lebanon
Columbus Area														***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.946	75.4	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.954	**82.4**	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.958	77.0	Franklin
St. Louis Area														***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.954	**82.4**	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.958	**83.3**	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.966	79.5	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.956	78.7	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.962	79.8	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.967	**84.5**	Maryland Heights (MO)

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2009 - OTB			2009 - Will Do		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	Round 4	RRF	Round 5	
Lake Michigan Area																	***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.972	**82.3**	**92.0**	0.971	**82.2**	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.965	77.5	**84.9**	0.964	77.4	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.965	79.8	**84.9**	0.964	79.7	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.961	80.1	**85.4**	0.960	80.0	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.951	80.8	78.9	0.949	80.7	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.955	**84.0**	**88.9**	0.953	**83.9**	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.945	78.1	81.0	0.943	78.0	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.946	**83.9**	81.8	0.945	**83.8**	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.971	75.4	**86.6**	0.970	75.3	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.971	77.0		0.970	77.0	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.960	73.9	**86.5**	0.959	73.8	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.965	75.6	82.8	0.964	75.5	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.948	**85.3**	**83.4**	0.947	**85.2**	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.940	77.1	77.6	0.939	77.0	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.947	80.5	81.5	0.945	80.3	Muskegon
Indianapolis Area																	***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.945	78.1	**83.7**	0.946	78.2	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.947	73.9	**83.8**	0.948	73.9	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.955	75.1	**83.7**	0.956	75.2	Fort B. Harrison
Detroit Area																	***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.947	81.4	**85.3**	0.947	81.4	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.968	81.3	**83.3**	0.969	81.4	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.937	77.5	79.1	0.938	77.5	Port Huron
Cleveland Area																	***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.937	**83.4**	**82.7**	0.941	**83.7**	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.942	74.7	**88.8**	0.945	75.0	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.949	81.9	**82.8**	0.954	**82.4**	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.934	78.1	81.4	0.935	78.2	
Cincinnati Area																	***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.941	77.5	**83.5**	0.942	77.6	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.967	81.9	**84.7**	0.968	82.0	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.947	**83.0**	79.0	0.948	**83.1**	Lebanon
Columbus Area																	***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.941	75.0	78.4	0.942	75.0	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.947	81.8	**82.6**	0.948	81.8	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.945	75.9	76.5	0.948	76.2	Franklin
St. Louis Area																	***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.938	81.0	**85.2**	0.932	80.5	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.942	**82.0**	**82.2**	0.939	81.7	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.956	78.7	81.9	0.954	78.5	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.938	77.2	77.4	0.937	77.1	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.955	79.3	**83.4**	0.955	79.3	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.955	**83.4**		0.954	**83.3**	Maryland Heights (MO)

Key Sites		4th High 8-hour Value					Des. Values (truncated)			2005 BY	2002 BY	2012 - OTB			2018 - OTB		
		'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average	Average	RRF	Round 5	Round 4	RRF	Round 5	
Lake Michigan Area																	***Lake Michigan Area***
Chiwaukee	550590019	88	78	93	79	85	**86**	83	**85**	84.7	**98.3**	0.956	80.9	**90.3**	0.900	76.2	Chiwaukee
Racine	551010017	82	69	95	71	77	82	78	81	80.3	**91.7**	0.947	76.1	**82.9**	0.886	71.2	Racine
Milwaukee-Bayside	550190085	92	73	93	73	83	**86**	79	83	82.7	**91.0**	0.944	78.0	**82.3**	0.880	72.7	Milwaukee-Bayside
Harrington Beach	550890009	99	72	94	72	84	**88**	79	83	83.3	**93.0**	0.939	78.3	**82.9**	0.870	72.5	Harrington Beach
Manitowoc	550710007	92	74	95	78	85	**87**	82	**86**	85.0	**87.0**	0.925	78.6	76.3	0.853	72.5	Manitowoc
Sheboygan	551170006	93	78	97	83	88	**89**	**86**	**89**	**88.0**	**97.0**	0.930	81.8	**86.4**	0.857	75.4	Sheboygan
Kewaunee	550610002	97	73	88	76	85	**86**	79	83	82.7	**89.3**	0.918	75.9	79.1	0.845	69.9	Kewaunee
Door County	550290004	93	78	101	79	92	**90**	**86**	**90**	**88.7**	**91.0**	0.919	81.5	79.3	0.843	74.7	Door County
Hammond	180892008	81	67	87	75	77	78	76	79	77.7	**88.3**	0.960	74.6	**86.3**	0.922	71.6	Hammond
Whiting	180890030		64	88	81	88	76	77	**85**	79.3		0.960	76.2		0.922	73.1	Whiting
Michigan City	180910005	82	70	84	75	73	78	76	77	77.0	**90.3**	0.942	72.5	**85.4**	0.884	68.1	Michigan City
Ogden Dunes	181270020	77	69	90	70	84	78	76	81	78.3	**86.3**	0.951	74.5	**82.0**	0.904	70.8	Ogden Dunes
Holland	260050003	96	79	94	91	94	**89**	**88**	**93**	**90.0**	**94.0**	0.920	**82.8**	81.0	0.846	76.1	Holland
Jenison	261390005	91	69	86	83	88	82	79	**85**	82.0	**86.0**	0.909	74.5	75.5	0.838	68.7	Jenison
Muskegon	261210039	94	70	90	90	86	84	83	**88**	**85.0**	**90.0**	0.918	78.0	79.4	0.846	71.9	Muskegon
Indianapolis Area																	***Indianapolis Area***
Noblesville	189571001	101	75	87	77	84	**87**	79	82	82.7	**93.7**	0.914	75.6	**82.0**	0.831	68.7	Noblesville
Fortville	180590003	92	72	80	75	81	81	75	78	78.0	**91.3**	0.916	71.4	**82.1**	0.835	65.1	Fortville
Fort B. Harrison	180970050	91	73	80	76	83	81	76	79	78.7	**90.0**	0.931	73.2	**82.4**	0.879	69.1	Fort B. Harrison
Detroit Area																	***Detroit Area***
New Haven	260990009	102	81	88	78	93	**90**	82	**86**	**86.0**	**92.3**	0.932	80.2	**83.5**	0.885	76.1	New Haven
Warren	260991003	101	71	89	78	91	**87**	79	**86**	84.0	**90.0**	0.961	80.7	81.9	0.924	77.6	Warren
Port Huron	261470005	87	74	88	78	89	83	80	**85**	82.7	**88.0**	0.913	75.5	77.0	0.858	70.9	Port Huron
Cleveland Area																	***Cleveland Area***
Ashtabula	390071001	99	81	93	86	92	**91**	**86**	**90**	**89.0**	**95.7**	0.910	81.0	80.2	0.844	75.1	Ashtabula
Geauga	390550004	97	75	88	70	68	**86**	77	75	79.3	**99.0**	0.916	72.7	**86.2**	0.848	67.3	Geauga
Eastlake	390850003	92	79	97	83	74	**89**	**86**	84	**86.3**	**92.7**	0.932	80.5	80.6	0.883	76.2	Eastlake
Akron	391530020	89	77	89	77	91	**85**	81	**85**	83.7	**93.3**	0.903	75.6	78.5	0.821	68.7	Akron
Cincinnati Area																	***Cincinnati Area***
Wilmington	390271002	96	78	83	81	82	**85**	80	82	82.3	**94.3**	0.910	74.9	81.1	0.830	68.3	Wilmington
Sycamore	390610006	93	76	89	81	90	**86**	82	**86**	84.7	**90.3**	0.948	80.3	**82.9**	0.881	74.6	Sycamore
Lebanon	391650007	95	81	92	86	88	**89**	**86**	**88**	**87.7**	**87.0**	0.921	80.7	77.0	0.846	74.2	Lebanon
Columbus Area																	***Columbus Area***
London	390970007	90	75	81	76	83	82	77	80	79.7	**88.7**	0.911	72.6	76.5	0.832	66.3	London
New Albany	390490029	94	78	92	82	87	**88**	84	**87**	**86.3**	**93.0**	0.922	79.6	80.2	0.845	73.0	New Albany
Franklin	290490028	84	73	86	79	79	81	79	81	80.3	**86.0**	0.923	74.1	74.7	0.859	69.0	Franklin
St. Louis Area																	***St. Louis Area***
W. Alton (MO)	291831002	91	77	89	91	89	**85**	**85**	**89**	**86.3**	**90.0**	0.911	78.6	**84.0**	0.868	74.9	W. Alton (MO)
Orchard (MO)	291831004	90	76	92	92	83	**86**	**86**	**89**	**87.0**	**90.0**	0.919	80.0	80.4	0.876	76.2	Orchard (MO)
Sunset Hills (MO)	291890004	88	70	89	80	89	82	79	**86**	82.3	**88.3**	0.937	77.1	80.6	0.897	73.9	Sunset Hills (MO)
Arnold (MO)	290990012	82	70	92	79	87	81	80	**86**	82.3	84.7	0.918	75.6	75.8	0.874	72.0	Arnold (MO)
Margaretta (MO)	295100086	90	72	91	76	91	84	79	**86**	83.0	**87.7**	0.939	77.9	**82.5**	0.896	74.4	Margaretta (MO)
Maryland Heights (MO)	291890014			88	84	94	**88**	**86**	**88**	**87.3**		0.936	81.7		0.894	78.1	Maryland Heights (MO)

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2009 Modeling Results		
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	**14.1**	**14.8**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	**14.4**	**15.8**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.9	**14.5**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.8	**14.5**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.7	**14.5**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	**14.2**	**14.8**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.4**	**15.3**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**15.1**	**16.0**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	**14.1**	**14.9**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.8	**15.5**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	12.4	13.8	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		13.0		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.8	**14.5**	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		13.4		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	13.4	**14.8**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	13.0	**14.5**	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	**14.2**	**15.8**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	13.1	**14.1**	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.8**	**17.7**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	13.1	**15.1**	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	13.5	**14.2**	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	13.1	13.5	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	13.5	**14.4**	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**15.2**	**16.1**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	**14.4**	**14.6**	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**15.0**	**15.3**	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	**14.0**	**14.1**	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.9	**14.6**	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	12.7	**14.1**	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	11.7	**14.0**	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	**14.5**	**15.5**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.8	13.6	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	**14.0**	**14.6**	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.9	13.6	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	13.4	**14.2**	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.7**	**15.2**	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.8	**16.3**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.5	**15.5**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.8	**14.2**	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	13.2	13.7	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	12.1	**15.4**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	**14.0**	**15.0**	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	12.6	13.6	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	13.0	**14.4**	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	12.3	13.6	Akron - W. Exchange

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2012 Modeling Results		
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	**14.0**	**14.6**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	**14.2**	**15.5**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.8	**14.3**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.7	**14.3**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.6	**14.3**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	**14.0**	**14.6**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.3**	**15.1**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**14.9**	**15.8**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	13.9	**14.7**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.7	**15.0**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	12.2	13.5	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		12.8		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.6	**14.2**	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		13.2		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	13.1	**14.9**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	12.8	**14.1**	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	13.9	**15.3**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	12.8	13.7	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.5**	**17.1**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	12.8	**14.7**	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	13.2	13.7	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	12.9	12.9	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	13.2	13.8	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**14.8**	**15.4**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	**14.0**	**14.0**	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**14.6**	**14.7**	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	13.6	13.5	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.6	**14.0**	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	12.4	13.5	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	11.4	13.4	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	**14.3**	**14.8**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.6	13.0	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	13.8	**14.0**	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.7	13.0	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	13.2	13.6	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.4**	**14.6**	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.5	**15.9**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.2	**15.0**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.5	13.7	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	12.9	13.2	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	11.9	**14.8**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	13.6	**14.3**	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	12.3	13.0	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	12.7	13.6	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	12.0	13.0	Akron - W. Exchange

			Annual Average Conc.					Design Values			2005 BY	2002 BY	2018 Modeling Results			
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03 - '05	'04 - '06	'05 - '07	Average w/ 2007	Average	Round 5 OTB	Round 5 Will Do	Round4	Key Site
Chicago - Washington HS	Cook	170310022	15.6	14.2	16.9	13.2	15.7	15.6	14.8	15.3	**15.2**	**15.9**	13.9	13.8	**14.4**	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	15.9	15.3	17.0	14.5	15.5	16.1	15.6	15.7	**15.8**	**17.1**	13.9	13.8	**15.0**	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	15.6	13.8	16.7	13.5	15.1	15.4	14.7	15.1	15.0	**15.6**	13.7	13.5	**14.1**	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	14.8	14.2	16.6	13.5	14.3	15.2	14.8	14.8	14.9	**15.6**	13.6	13.4	**14.1**	Chicago - Lawndale
Blue Island	Cook	170312001	14.9	14.1	16.4	13.2	14.3	15.1	14.6	14.6	14.8	**15.6**	13.4	13.3	**14.1**	Blue Island
Summit	Cook	170313301	15.6	14.2	16.9	13.8	14.8	15.6	15.0	15.2	**15.2**	**16.0**	13.9	13.8	**14.4**	Summit
Cicero	Cook	170316005	16.8	15.2	16.3	14.3	14.8	16.1	15.3	15.1	**15.5**	**16.4**	**14.2**	**14.0**	**14.9**	Cicero
Granite City	Madison	171191007	17.5	15.4	18.2	16.3	15.1	17.0	16.6	16.5	**16.7**	**17.3**	**14.3**	**14.2**	**15.5**	Granite City
E. St. Louis	St. Clair	171630010	14.9	14.7	17.1	14.5	15.6	15.6	15.4	15.7	**15.6**	**16.2**	13.4	13.3	**14.5**	E. St. Louis
Jeffersonville	Clark	180190005	15.8	15.1	18.5	15.0	16.5	16.5	16.2	16.7	**16.4**	**17.2**	13.4	13.4	**14.4**	Jeffersonville
Jasper	Dubois	180372001	15.7	14.4	16.9	13.5	14.4	15.7	14.9	14.9	**15.2**	**15.5**	11.8	11.9	13.0	Jasper
Gary	Lake	180890031			16.8	13.3	14.5	16.8	15.1	14.9	**15.6**		12.4	12.4		Gary
Indy-Washington Park	Marion	180970078	15.5	14.3	16.4	14.1	15.8	15.4	14.9	15.4	**15.3**	**16.2**	12.0	12.1	13.7	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	16.2	15.0	17.9	14.2	16.1	16.4	15.7	16.1	**16.0**		12.6	12.7		Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	16.3	15.0	17.5	14.1	15.9	16.3	15.5	15.8	**15.9**	**16.6**	12.6	12.6	**14.0**	Indy- Michigan Street
Allen Park	Wayne	261630001	15.2	14.2	15.9	13.2	12.8	15.1	14.4	14.0	14.5	**15.8**	12.4	12.4	13.3	Allen Park
Southwest HS	Wayne	261630015	16.6	15.4	17.2	14.7	14.5	16.4	15.8	15.5	**15.9**	**17.3**	13.5	13.5	**14.4**	Southwest HS
Linwood	Wayne	261630016	15.8	13.7	16.0	13.0	13.9	15.2	14.2	14.3	14.6	**15.5**	12.5	12.5	13.0	Linwood
Dearborn	Wayne	261630033	19.2	16.8	18.6	16.1	16.9	18.2	17.2	17.2	**17.5**	**19.3**	**15.1**	**15.1**	**16.1**	Dearborn
Wyandotte	Wayne	261630036	16.3	13.7	16.4	12.9	13.4	15.5	14.3	14.2	14.7	**16.6**	12.5	12.5	13.9	Wyandotte
Middleton	Butler	390170003	17.2	14.1	19.0	14.1	15.4	16.8	15.7	16.2	**16.2**	**16.5**	12.8	12.8	13.1	Middleton
Fairfield	Butler	390170016	15.8	14.7	17.9	14.0	14.9	16.1	15.5	15.6	**15.8**	**15.9**	12.5	12.6	12.2	Fairfield
Cleveland-28th Street	Cuyahoga	390350027	15.4	15.6	17.3	13.0	14.5	16.1	15.3	14.9	**15.4**	**16.5**	12.7	12.9	12.9	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	17.6	17.5	19.2	14.9	16.2	18.1	17.2	16.8	**17.4**	**18.4**	**14.3**	**14.5**	**14.4**	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	16.4	15.3	19.3	14.1	15.3	17.0	16.2	16.2	**16.5**	**16.7**	13.5	13.7	13.1	Cleveland-Broadway
Cleveland-E14 & Orange	Cuyahoga	390350060	17.2	16.4	19.4	15.0	15.9	17.7	16.9	16.8	**17.1**	**17.6**	**14.1**	**14.2**	13.7	Cleveland-E14 & Orange
Newburg Hts - Harvard Ave	Cuyahoga	390350065	15.6	15.2	18.6	13.1	15.8	16.5	15.6	15.8	**16.0**	**16.2**	13.1	13.3	12.6	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	16.4	15.0	16.4	13.6	14.6	15.9	15.0	14.9	**15.3**	**16.5**	12.0	12.1	13.0	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	15.3	14.6	16.5	13.8	14.7	15.5	15.0	15.0	**15.1**	**16.0**	11.9	11.9	12.5	Columbus - Ann Street
Columbus - Maple Canyon	Franklin	390490081	14.9	13.6	14.6	12.9	13.1	14.4	13.7	13.5	13.9	**16.0**	10.9	11.0	12.5	Columbus - Maple Canyon
Cincinnati - Seymour	Hamilton	390610014	17.0	15.9	19.8	15.5	16.5	17.6	17.1	17.3	**17.3**	**17.7**	13.8	13.9	**14.0**	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	15.5	14.6	17.5	13.6	15.1	15.9	15.2	15.4	**15.5**	**15.7**	12.2	12.3	12.3	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	16.7	16.0	19.1	14.9	15.9	17.3	16.7	16.6	**16.9**	**17.3**	13.4	13.4	13.2	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	15.7	14.9	16.9	14.5	14.8	15.8	15.4	15.4	**15.6**	**16.0**	12.3	12.4	12.2	Sharonville
Norwood	Hamilton	390617001	16.0	15.3	18.4	14.4	15.1	16.6	16.0	16.0	**16.2**	**16.3**	12.8	12.8	12.8	Norwood
St. Bernard	Hamilton	390618001	17.3	16.4	20.0	15.9	16.1	17.9	17.4	17.3	**17.6**	**17.3**	**14.0**	**14.1**	13.8	St. Bernard
Steubenville	Jefferson	390810016	17.7	15.9	16.4	13.8	16.2	16.7	15.4	15.5	**15.8**	**17.7**	12.7	12.7	**16.2**	Steubenville
Mingo Junction	Jefferson	390811001	17.3	16.2	18.1	14.6	15.6	17.2	16.3	16.1	**16.5**	**17.5**	13.4	13.4	**15.3**	Mingo Junction
Ironton	Lawrence	390870010	14.3	13.7	17.0	14.4	15.0	15.0	15.0	15.5	**15.2**	**15.7**	12.3	12.3	13.2	Ironton
Dayton	Montgomery	391130032	15.9	14.5	17.4	13.6	15.6	15.9	15.2	15.5	**15.5**	**15.9**	12.4	12.5	12.3	Dayton
New Boston	Scioto	391450013	14.7	13.0	16.2	14.3	14.0	14.6	14.5	14.8	14.7	**17.1**	11.6	11.6	**14.2**	New Boston
Canton - Dueber	Stark	391510017	16.8	15.6	17.8	14.6	15.9	16.7	16.0	16.1	**16.3**	**17.3**	13.3	13.3	13.6	Canton - Dueber
Canton - Market	Stark	391510020	15.0	14.1	16.6	11.9	14.4	15.2	14.2	14.3	14.6	**15.7**	11.9	12.0	12.2	Canton - Market
Akron - Brittain	Summit	391530017	15.4	15.0	16.4	13.5	14.4	15.6	15.0	14.8	**15.1**	**16.4**	12.3	12.3	12.9	Akron - Brittain
Akron - W. Exchange	Summit	391530023	14.2	13.9	15.7	12.8	13.7	14.6	14.1	14.1	14.3	**15.6**	11.5	11.6	12.2	Akron - W. Exchange

24-Hour $PM_{2.5}$			98th Percentile (24-hour)					Design Values			Base Year	Round 5 Modeling Results			
Key Site	County	Site ID	'03	'04	'05	'06	'07	'03-'05	'04-'06	'05-'07	Average w/ 2007	2009	2012	2018	Key Site
Chicago - Washington HS	Cook	170310022	37.7	32.5	45.7	27.0	35.7	38.6	35.1	36.1	36.6	36	36	35	Chicago - Washington HS
Chicago - Mayfair	Cook	170310052	37.3	38.8	48.3	31.6	39.4	41.5	39.6	39.8	40.3	36	36	36	Chicago - Mayfair
Chicago - Springfield	Cook	170310057	36.4	33.1	46.5	27.7	38.9	38.7	35.8	37.7	37.4	32	32	31	Chicago - Springfield
Chicago - Lawndale	Cook	170310076	32.6	39.7	45.1	29.0	37.2	39.1	37.9	37.1	38.1	35	35	34	Chicago - Lawndale
McCook	Cook	170311016									43.0	39	39	38	McCook
Blue Island	Cook	170312001	39.6	38.5	43.8	28.1	35.1	40.6	36.8	35.7	37.7	34	34	33	Blue Island
Schiller Park	Cook	170313103		40.7	50.3	30.0	36.6	45.5	40.3	39.0	41.6	39	39	39	Schiller Park
Summit	Cook	170313301	38.4	42.4	49.1	27.4	36.7	43.3	39.6	37.7	40.2	38	38	37	Summit
Maywood	Cook	170316005	38.5	42.5	44.6	29.2	36.9	41.9	38.8	36.9	39.2	38	38	37	Maywood
Granite City	Madison	171191007	40.8	35.4	44.1	36.3	36.0	40.1	38.6	38.8	39.2	33	33	32	Granite City
E. St. Louis	St. Clair	171630010	32.6	30.2	39.6	29.2	33.1	34.1	33.0	34.0	33.7	28	28	28	E. St. Louis
Jeffersonville	Clark	180190005		28.4	45.5	35.9	43.3	37.0	36.6	41.6	38.4	29	31	31	Jeffersonville
Jasper	Dubois	180372001	39.5	30.0	41.2	31.6	39.5	36.9	34.3	37.4	36.2	28	29	28	Jasper
Gary - IITRI	Lake	180890022									39.0	34	34	35	Gary - IITRI
Gary - Burr School	Lake	180890026									39.0	33	34	32	Gary - Burr School
Gary	Lake	180890031			38.7	27.1	36.2	38.7	32.9	34.0	35.2	24	24	27	Gary
Indy-West Street	Marion	180970043									38.0	33	33	33	Indy-West Street
Indy-English Avenue	Marion	180970066									38.0	32	32	32	Indy-English Avenue
Indy-Washington Park	Marion	180970078	39.3	31.0	42.5	31.7	37.6	37.6	35.1	37.3	36.6	31	31	32	Indy-Washington Park
Indy-W 18th Street	Marion	180970081	36.2	31.9	45.7	34.8	38.4	37.9	37.5	39.6	38.3	31	31	31	Indy-W 18th Street
Indy- Michigan Street	Marion	180970083	36.7	31.3	40.3	33.5	37.2	36.1	35.0	37.0	36.0	28	28	29	Indy- Michigan Street
Luna Pier	Monroe	261150005	34.7	35.0	49.3	32.6	32.2	39.7	39.0	38.0	38.9	32	32	31	Luna Pier
Oak Park	Oakland	261250001	36.6	32.5	52.2	33.0	35.3	40.4	39.2	40.2	39.9	36	36	35	Oak Park
Port Huron	St. Clair	261470005	37.2	32.2	47.6	37.9	36.3	39.0	39.2	40.6	39.6	34	34	33	Port Huron
Ypsilanti	Washtenaw	261610008	38.8	31.5	52.1	31.3	34.5	40.8	38.3	39.3	39.5	35	35	34	Ypsilanti
Allen Park	Wayne	261630001	40.5	36.9	43.0	34.1	35.9	40.1	38.0	37.7	38.6	35	34	33	Allen Park
Southwest HS	Wayne	261630015	33.6	36.0	49.7	36.2	34.0	39.8	40.6	40.0	40.1	35	35	33	Southwest HS
Linwood	Wayne	261630016	46.2	38.3	51.8	36.9	34.8	45.4	42.3	41.2	43.0	39	39	38	Linwood
E 7 Mile	Wayne	261630019	37.1	35.0	52.3	36.2	33.0	41.5	41.2	40.5	41.0	38	38	37	E 7 Mile
Dearborn	Wayne	261630033	42.8	39.4	50.2	43.1	36.6	44.1	44.2	43.3	43.9	40	40	39	Dearborn
Wyandotte	Wayne	261630036	34.8	32.3	46.7	33.2	28.6	37.9	37.4	36.2	37.2	35	35	34	Wyandotte
Newberry	Wayne	261630038		36.8	57.5	28.6	33.4		39.1	39.8	42.7	38	37	36	Newberry
FIA	Wayne	261630039			43.9	32.4	34.8			37.0	39.7	33	33	31	FIA
Middleton	Butler	390170003	38.6	37.2	47.6	30.2	37.1	41.1	38.3	38.3	39.3	28	28	27	Middleton
Fairfield	Butler	390170016	34.8	32.2	43.4	35.2	34.5	36.8	36.9	37.7	37.1	27	28	27	Fairfield
	Butler	390170017	34.6	34.3	44.9			37.9	39.6		40.8	29	29	28	
Cleveland-28th Street	Cuyahoga	390350027	41.3	40.9	35.7	31.5	39.0	39.3	36.0	35.4	36.9	32	32	31	Cleveland-28th Street
Cleveland-St. Tikhon	Cuyahoga	390350038	47.3	42.5	51.2	36.1	39.7	44.9	47.0	42.3	44.2	36	35	34	Cleveland-St. Tikhon
Cleveland-Broadway	Cuyahoga	390350045	42.2	36.1	46.2	29.5	37.0	41.5	37.3	37.6	38.8	31	30	29	Cleveland-Broadway
Cleveland-GT Craig	Cuyahoga	390350060	45.5	42.2	49.5	31.0	38.7	45.7	40.9	39.7	42.1	37	37	35	Cleveland-GT Craig
Newburg Hts - Harvard Ave	Cuyahoga	390350065	39.1	36.1	47.9	27.8	39.1	41.0	37.3	38.3	38.9	31	30	30	Newburg Hts - Harvard Ave
Columbus - Fairgrounds	Franklin	390490024	39.2	35.1	45.0	34.0	34.2	39.8	38.0	37.7	38.5	33	32	31	Columbus - Fairgrounds
Columbus - Ann Street	Franklin	390490025	37.0	35.5	44.9	34.0	35.5	39.1	38.1	38.1	38.5	31	31	30	Columbus - Ann Street
Cincinnait	Hamilton	390610006			45.0	33.3	34.7			37.7	40.6	27	28	27	Cincinnait
Cincinnati - Seymour	Hamilton	390610014	37.8	42.0	38.5	35.2	38.1	39.4	38.6	37.3	38.4	26	25	24	Cincinnati - Seymour
Cincinnati - Taft Ave	Hamilton	390610040	31.9	30.5	45.8	32.8	34.7	36.1	36.4	37.8	36.7	24	24	23	Cincinnati - Taft Ave
Cincinnati - 8th Ave	Hamilton	390610042	33.8	31.9	44.4	34.5	35.9	36.7	36.9	38.3	37.3	28	28	27	Cincinnati - 8th Ave
Sharonville	Hamilton	390610043	37.3	31.4	39.9	34.9	34.0	36.2	35.4	36.3	36.0	28	28	27	Sharonville
Norwood	Hamilton	390617001	37.1	34.6	47.1	34.0	33.7	39.6	38.6	38.3	38.8	30	30	29	Norwood
St. Bernard	Hamilton	390618001	35.8	33.9	51.4	36.1	35.4	40.4	40.5	41.0	40.6	30	30	29	St. Bernard
Steubenville	Jefferson	390810016	39.6	43.8	43.8	32.1	43.5	42.4	39.9	39.8	40.7	29	28	28	Steubenville
Mingo Junction	Jefferson	390811001	40.9	51.5	44.2	32.9	35.4	45.5	42.9	37.5	42.0	30	30	30	Mingo Junction
Dayton	Montgomery	391130032	42.7	32.5	45.0	30.3	36.9	40.1	35.9	37.4	37.8	30	30	30	Dayton
Canton - Dueber	Stark	391510017	34.2	36.3	47.6	32.2	33.4	39.4	38.7	37.7	38.6	28	28	27	Canton - Dueber
Akron - Brittain	Summit	391530017	36.9	36.9	45.2	31.5	33.3	39.7	37.9	36.7	38.1	30	30	29	Akron - Brittain
Green Bay - Est High	Brown	550090005	33.5	32.3	41.5	36.9	37.1	35.8	36.9	38.5	37.1	35	34	32	Green Bay - Est High
Madison	Dane	550250047	32.0	31.9	40.1	33.4	44.3	34.7	35.1	39.3	36.4	32	31	29	Madison
Milwaukee-Health Center	Milwaukee	550790010	33.2	38.4	38.7	40.7	40.6	36.8	39.3	40.0	38.7	35	34	33	Milwaukee-Health Center
Milwaukee-SER Hdqs	Milwaukee	550790026	29.6	28.7	41.5	42.6	39.8	33.3	37.6	41.3	37.4	34	34	33	Milwaukee-SER Hdqs
Milwaukee-Virginia FS	Milwaukee	550790043	39.2	41.4	37.1	44.0	38	39.2	40.8	39.7	39.9	36	36	36	Milwaukee-Virginia FS
Milwaukee- Fire Dept Hdqs	Milwaukee	550790099	33.7	38.9	37.1	38.3	40.7	36.6	38.1	38.7	37.8	33	32	32	Milwaukee- Fire Dept Hdqs
Waukesha	Waukesha	551330027	29.1	38.4	41.1	28.2	33.8	36.2	35.9	34.4	35.5	31	31	29	Waukesha

PM2.5 RRFs by Species and Season (2009)						
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
1703100521	IL	Cook	winter	so4	0.1772	0.9342
1703100521	IL	Cook	winter	no3	0.3099	1.0128
1703100521	IL	Cook	winter	ocm	0.2147	0.9942
1703100521	IL	Cook	winter	ec	0.0372	0.888
1703100521	IL	Cook	winter	soil	0.0242	1.1674
1703100521	IL	Cook	winter	nh4	0.1421	0.97
1703100521	IL	Cook	winter	pbw	0.0947	0.9678
1703100521	IL	Cook	spring	so4	0.32	0.8018
1703100521	IL	Cook	spring	no3	0.0609	0.9385
1703100521	IL	Cook	spring	ocm	0.2742	1.0629
1703100521	IL	Cook	spring	ec	0.0501	0.8712
1703100521	IL	Cook	spring	soil	0.0505	1.1796
1703100521	IL	Cook	spring	nh4	0.1203	0.8619
1703100521	IL	Cook	spring	pbw	0.0984	0.8492
1703100521	IL	Cook	summer	so4	0.3089	0.725
1703100521	IL	Cook	summer	no3	0	1.0124
1703100521	IL	Cook	summer	ocm	0.1599	1.069
1703100521	IL	Cook	summer	ec	0.0351	0.8683
1703100521	IL	Cook	summer	soil	0.0318	1.204
1703100521	IL	Cook	summer	nh4	0.0932	0.7354
1703100521	IL	Cook	summer	pbw	0.094	0.7217
1703100521	IL	Cook	fall	so4	0.1872	0.9151
1703100521	IL	Cook	fall	no3	0.1628	0.9408
1703100521	IL	Cook	fall	ocm	0.2389	1.0091
1703100521	IL	Cook	fall	ec	0.0403	0.8623
1703100521	IL	Cook	fall	soil	0.0284	1.1443
1703100521	IL	Cook	fall	nh4	0.1062	0.9247
1703100521	IL	Cook	fall	pbw	0.0614	0.9233
1711910071	IL	Madison	winter	so4	0.213	0.9195
1711910071	IL	Madison	winter	no3	0.2705	1.0306
1711910071	IL	Madison	winter	ocm	0.2093	0.9289
1711910071	IL	Madison	winter	ec	0.0434	0.9083
1711910071	IL	Madison	winter	soil	0.0306	1.1782
1711910071	IL	Madison	winter	nh4	0.1528	0.9513
1711910071	IL	Madison	winter	pbw	0.0804	0.9243
1711910071	IL	Madison	spring	so4	0.3194	0.7717
1711910071	IL	Madison	spring	no3	0.0189	0.8611
1711910071	IL	Madison	spring	ocm	0.2455	1.1103
1711910071	IL	Madison	spring	ec	0.0564	1.0046
1711910071	IL	Madison	spring	soil	0.0459	1.2252
1711910071	IL	Madison	spring	nh4	0.1121	0.7894
1711910071	IL	Madison	spring	pbw	0.1085	0.7783
1711910071	IL	Madison	summer	so4	0.313	0.705
1711910071	IL	Madison	summer	no3	0	0.884
1711910071	IL	Madison	summer	ocm	0.153	1.1546
1711910071	IL	Madison	summer	ec	0.0345	1.0513
1711910071	IL	Madison	summer	soil	0.0302	1.2532
1711910071	IL	Madison	summer	nh4	0.102	0.7409
1711910071	IL	Madison	summer	pbw	0.1096	0.7133
1711910071	IL	Madison	fall	so4	0.2058	0.9037
1711910071	IL	Madison	fall	no3	0.1308	0.9426
1711910071	IL	Madison	fall	ocm	0.259	1.0233
1711910071	IL	Madison	fall	ec	0.0563	0.9248
1711910071	IL	Madison	fall	soil	0.0549	1.1412
1711910071	IL	Madison	fall	nh4	0.1073	0.9185
1711910071	IL	Madison	fall	pbw	0.0655	0.918

Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
1803720011	IN	Dubois	winter	so4	0.2669	0.8833
1803720011	IN	Dubois	winter	no3	0.2548	0.9526
1803720011	IN	Dubois	winter	ocm	0.1747	0.9374
1803720011	IN	Dubois	winter	ec	0.0313	0.9319
1803720011	IN	Dubois	winter	soil	0.0192	1.1349
1803720011	IN	Dubois	winter	nh4	0.1646	0.9069
1803720011	IN	Dubois	winter	pbw	0.0885	0.9006
1803720011	IN	Dubois	spring	so4	0.4141	0.6808
1803720011	IN	Dubois	spring	no3	0.0022	0.8106
1803720011	IN	Dubois	spring	ocm	0.178	0.9997
1803720011	IN	Dubois	spring	ec	0.0324	0.9083
1803720011	IN	Dubois	spring	soil	0.0218	1.1284
1803720011	IN	Dubois	spring	nh4	0.1432	0.7075
1803720011	IN	Dubois	spring	pbw	0.1556	0.6916
1803720011	IN	Dubois	summer	so4	0.3687	0.644
1803720011	IN	Dubois	summer	no3	0	0.8029
1803720011	IN	Dubois	summer	ocm	0.1174	1.0136
1803720011	IN	Dubois	summer	ec	0.0207	0.913
1803720011	IN	Dubois	summer	soil	0.0213	1.1988
1803720011	IN	Dubois	summer	nh4	0.1168	0.6789
1803720011	IN	Dubois	summer	pbw	0.1246	0.6613
1803720011	IN	Dubois	fall	so4	0.2964	0.8232
1803720011	IN	Dubois	fall	no3	0.138	0.8797
1803720011	IN	Dubois	fall	ocm	0.2116	0.9861
1803720011	IN	Dubois	fall	ec	0.0437	0.9019
1803720011	IN	Dubois	fall	soil	0.03	1.1387
1803720011	IN	Dubois	fall	nh4	0.1449	0.8444
1803720011	IN	Dubois	fall	pbw	0.0941	0.8558
1809700811	IN	Marion	winter	so4	0.2358	0.9192
1809700811	IN	Marion	winter	no3	0.2729	0.9769
1809700811	IN	Marion	winter	ocm	0.1851	0.9546
1809700811	IN	Marion	winter	ec	0.0385	0.8647
1809700811	IN	Marion	winter	soil	0.0239	1.0835
1809700811	IN	Marion	winter	nh4	0.1561	0.9446
1809700811	IN	Marion	winter	pbw	0.0877	0.944
1809700811	IN	Marion	spring	so4	0.3745	0.6868
1809700811	IN	Marion	spring	no3	0.0167	0.8082
1809700811	IN	Marion	spring	ocm	0.2034	0.9881
1809700811	IN	Marion	spring	ec	0.0447	0.8547
1809700811	IN	Marion	spring	soil	0.0376	1.0625
1809700811	IN	Marion	spring	nh4	0.1313	0.7182
1809700811	IN	Marion	spring	pbw	0.1309	0.7056
1809700811	IN	Marion	summer	so4	0.3582	0.6529
1809700811	IN	Marion	summer	no3	0	0.8099
1809700811	IN	Marion	summer	ocm	0.1231	1.0043
1809700811	IN	Marion	summer	ec	0.03	0.8444
1809700811	IN	Marion	summer	soil	0.0253	1.0918
1809700811	IN	Marion	summer	nh4	0.1114	0.6854
1809700811	IN	Marion	summer	pbw	0.1163	0.6674
1809700811	IN	Marion	fall	so4	0.2751	0.8538
1809700811	IN	Marion	fall	no3	0.149	0.9452
1809700811	IN	Marion	fall	ocm	0.223	0.9648
1809700811	IN	Marion	fall	ec	0.0525	0.8412
1809700811	IN	Marion	fall	soil	0.0358	1.089
1809700811	IN	Marion	fall	nh4	0.1378	0.8905
1809700811	IN	Marion	fall	pbw	0.0865	0.8888

Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
2616300331	MI	Wayne	winter	so4	0.1587	0.9206
2616300331	MI	Wayne	winter	no3	0.2394	0.9813
2616300331	MI	Wayne	winter	ocm	0.3193	1.0781
2616300331	MI	Wayne	winter	ec	0.0383	0.9279
2616300331	MI	Wayne	winter	soil	0.0541	1.0206
2616300331	MI	Wayne	winter	nh4	0.1188	0.9518
2616300331	MI	Wayne	winter	pbw	0.0714	0.9566
2616300331	MI	Wayne	spring	so4	0.3383	0.7398
2616300331	MI	Wayne	spring	no3	0.0259	0.8787
2616300331	MI	Wayne	spring	ocm	0.3543	1.0234
2616300331	MI	Wayne	spring	ec	0.0504	0.8671
2616300331	MI	Wayne	spring	soil	0.0915	1.0153
2616300331	MI	Wayne	spring	nh4	0.1191	0.7818
2616300331	MI	Wayne	spring	pbw	0.1126	0.7619
2616300331	MI	Wayne	summer	so4	0.3311	0.6681
2616300331	MI	Wayne	summer	no3	0	0.8431
2616300331	MI	Wayne	summer	ocm	0.2297	1.0029
2616300331	MI	Wayne	summer	ec	0.0362	0.8332
2616300331	MI	Wayne	summer	soil	0.061	1.0177
2616300331	MI	Wayne	summer	nh4	0.1027	0.6974
2616300331	MI	Wayne	summer	pbw	0.1073	0.6754
2616300331	MI	Wayne	fall	so4	0.1898	0.854
2616300331	MI	Wayne	fall	no3	0.1075	0.9367
2616300331	MI	Wayne	fall	ocm	0.3689	1.0607
2616300331	MI	Wayne	fall	ec	0.0546	0.8862
2616300331	MI	Wayne	fall	soil	0.1676	1.0317
2616300331	MI	Wayne	fall	nh4	0.0866	0.8919
2616300331	MI	Wayne	fall	pbw	0.0553	0.8821
3903500381	OH	Cuyahoga	winter	so4	0.2117	0.8993
3903500381	OH	Cuyahoga	winter	no3	0.2665	0.9856
3903500381	OH	Cuyahoga	winter	ocm	0.2048	0.9716
3903500381	OH	Cuyahoga	winter	ec	0.0413	0.8903
3903500381	OH	Cuyahoga	winter	soil	0.0465	1.0959
3903500381	OH	Cuyahoga	winter	nh4	0.1459	0.9416
3903500381	OH	Cuyahoga	winter	pbw	0.0832	0.9541
3903500381	OH	Cuyahoga	spring	so4	0.3334	0.7145
3903500381	OH	Cuyahoga	spring	no3	0.0374	0.8393
3903500381	OH	Cuyahoga	spring	ocm	0.2068	1.0899
3903500381	OH	Cuyahoga	spring	ec	0.052	0.9362
3903500381	OH	Cuyahoga	spring	soil	0.0697	1.0601
3903500381	OH	Cuyahoga	spring	nh4	0.1256	0.7666
3903500381	OH	Cuyahoga	spring	pbw	0.115	0.7761
3903500381	OH	Cuyahoga	summer	so4	0.3241	0.6303
3903500381	OH	Cuyahoga	summer	no3	0	0.89
3903500381	OH	Cuyahoga	summer	ocm	0.1306	1.0998
3903500381	OH	Cuyahoga	summer	ec	0.0419	0.9354
3903500381	OH	Cuyahoga	summer	soil	0.0583	1.0906
3903500381	OH	Cuyahoga	summer	nh4	0.1074	0.7038
3903500381	OH	Cuyahoga	summer	pbw	0.1183	0.6674
3903500381	OH	Cuyahoga	fall	so4	0.2055	0.8193
3903500381	OH	Cuyahoga	fall	no3	0.1275	0.9189
3903500381	OH	Cuyahoga	fall	ocm	0.2234	1.0245
3903500381	OH	Cuyahoga	fall	ec	0.0499	0.8913
3903500381	OH	Cuyahoga	fall	soil	0.0675	1.0927
3903500381	OH	Cuyahoga	fall	nh4	0.1034	0.8615
3903500381	OH	Cuyahoga	fall	pbw	0.0637	0.8564

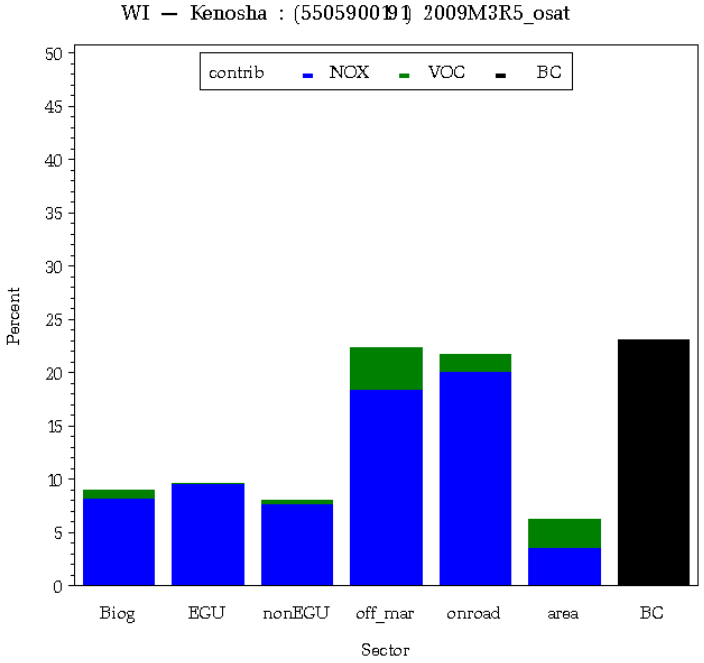
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3904900241	OH	Franklin	winter	so4	0.2555	0.8622
3904900241	OH	Franklin	winter	no3	0.2373	1.0002
3904900241	OH	Franklin	winter	ocm	0.2082	0.974
3904900241	OH	Franklin	winter	ec	0.0375	0.8537
3904900241	OH	Franklin	winter	soil	0.0259	1.0844
3904900241	OH	Franklin	winter	nh4	0.1495	0.9261
3904900241	OH	Franklin	winter	pbw	0.0861	0.9274
3904900241	OH	Franklin	spring	so4	0.3754	0.6615
3904900241	OH	Franklin	spring	no3	0.0176	0.8436
3904900241	OH	Franklin	spring	ocm	0.2069	1.062
3904900241	OH	Franklin	spring	ec	0.0405	0.8678
3904900241	OH	Franklin	spring	soil	0.0371	1.0551
3904900241	OH	Franklin	spring	nh4	0.1296	0.7212
3904900241	OH	Franklin	spring	pbw	0.128	0.6992
3904900241	OH	Franklin	summer	so4	0.3703	0.622
3904900241	OH	Franklin	summer	no3	0	0.9056
3904900241	OH	Franklin	summer	ocm	0.1343	1.0654
3904900241	OH	Franklin	summer	ec	0.0311	0.8565
3904900241	OH	Franklin	summer	soil	0.0267	1.0667
3904900241	OH	Franklin	summer	nh4	0.1142	0.7021
3904900241	OH	Franklin	summer	pbw	0.1186	0.6614
3904900241	OH	Franklin	fall	so4	0.2692	0.8119
3904900241	OH	Franklin	fall	no3	0.1186	0.9099
3904900241	OH	Franklin	fall	ocm	0.2489	1.019
3904900241	OH	Franklin	fall	ec	0.0533	0.8371
3904900241	OH	Franklin	fall	soil	0.0423	1.0924
3904900241	OH	Franklin	fall	nh4	0.1217	0.8539
3904900241	OH	Franklin	fall	pbw	0.0821	0.8519
3906100141	OH	Hamilton	winter	so4	0.2685	0.8104
3906100141	OH	Hamilton	winter	no3	0.2378	1.0886
3906100141	OH	Hamilton	winter	ocm	0.19	0.961
3906100141	OH	Hamilton	winter	ec	0.035	0.8969
3906100141	OH	Hamilton	winter	soil	0.0229	1.4146
3906100141	OH	Hamilton	winter	nh4	0.1583	0.9077
3906100141	OH	Hamilton	winter	pbw	0.0874	0.8687
3906100141	OH	Hamilton	spring	so4	0.3583	0.6331
3906100141	OH	Hamilton	spring	no3	0.0025	1.0155
3906100141	OH	Hamilton	spring	ocm	0.1986	1.0798
3906100141	OH	Hamilton	spring	ec	0.0466	0.9228
3906100141	OH	Hamilton	spring	soil	0.0289	1.3785
3906100141	OH	Hamilton	spring	nh4	0.1215	0.6968
3906100141	OH	Hamilton	spring	pbw	0.128	0.6307
3906100141	OH	Hamilton	summer	so4	0.3722	0.577
3906100141	OH	Hamilton	summer	no3	0	1.0923
3906100141	OH	Hamilton	summer	ocm	0.121	1.082
3906100141	OH	Hamilton	summer	ec	0.0309	0.9099
3906100141	OH	Hamilton	summer	soil	0.0199	1.537
3906100141	OH	Hamilton	summer	nh4	0.1178	0.6441
3906100141	OH	Hamilton	summer	pbw	0.1261	0.5734
3906100141	OH	Hamilton	fall	so4	0.2608	0.7754
3906100141	OH	Hamilton	fall	no3	0.1184	0.9857
3906100141	OH	Hamilton	fall	ocm	0.213	1.0235
3906100141	OH	Hamilton	fall	ec	0.0512	0.8876
3906100141	OH	Hamilton	fall	soil	0.0328	1.4007
3906100141	OH	Hamilton	fall	nh4	0.1254	0.846
3906100141	OH	Hamilton	fall	pbw	0.0828	0.8172

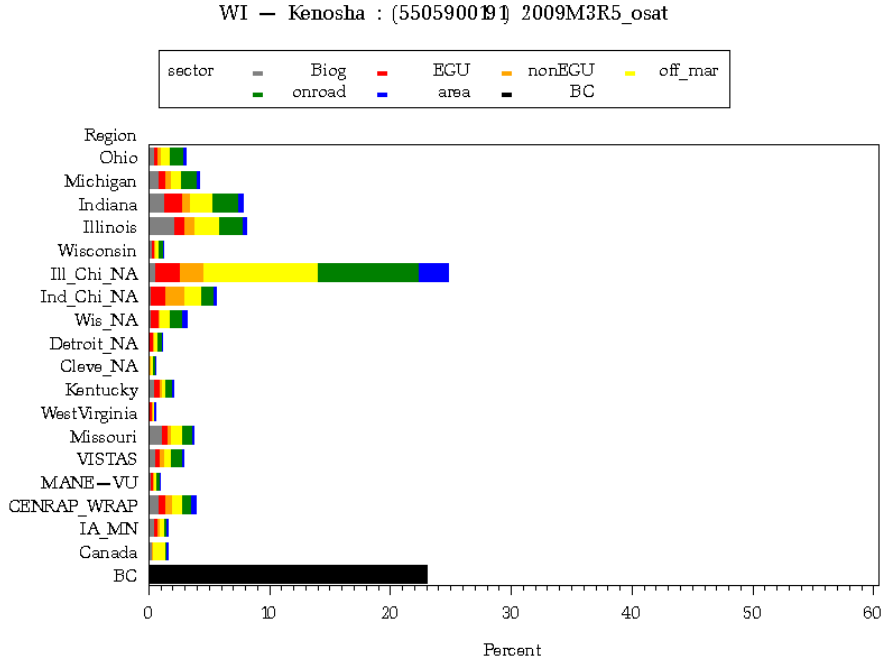
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3908110011	OH	Jefferson	winter	so4	0.2367	0.8217
3908110011	OH	Jefferson	winter	no3	0.1709	1.0522
3908110011	OH	Jefferson	winter	ocm	0.3288	0.8819
3908110011	OH	Jefferson	winter	ec	0.0435	0.9091
3908110011	OH	Jefferson	winter	soil	0.0272	0.4368
3908110011	OH	Jefferson	winter	nh4	0.1199	0.8904
3908110011	OH	Jefferson	winter	pbw	0.073	0.8583
3908110011	OH	Jefferson	spring	so4	0.3508	0.6666
3908110011	OH	Jefferson	spring	no3	0.0154	0.9156
3908110011	OH	Jefferson	spring	ocm	0.3078	0.9995
3908110011	OH	Jefferson	spring	ec	0.0395	0.9853
3908110011	OH	Jefferson	spring	soil	0.0407	0.4844
3908110011	OH	Jefferson	spring	nh4	0.114	0.7054
3908110011	OH	Jefferson	spring	pbw	0.1095	0.6713
3908110011	OH	Jefferson	summer	so4	0.3779	0.6156
3908110011	OH	Jefferson	summer	no3	0	1.0837
3908110011	OH	Jefferson	summer	ocm	0.2098	1.0145
3908110011	OH	Jefferson	summer	ec	0.0308	0.9689
3908110011	OH	Jefferson	summer	soil	0.0323	0.3632
3908110011	OH	Jefferson	summer	nh4	0.1065	0.6428
3908110011	OH	Jefferson	summer	pbw	0.1007	0.625
3908110011	OH	Jefferson	fall	so4	0.2315	0.7694
3908110011	OH	Jefferson	fall	no3	0.0702	1.0302
3908110011	OH	Jefferson	fall	ocm	0.372	0.9312
3908110011	OH	Jefferson	fall	ec	0.051	0.9086
3908110011	OH	Jefferson	fall	soil	0.0344	0.4555
3908110011	OH	Jefferson	fall	nh4	0.0859	0.8284
3908110011	OH	Jefferson	fall	pbw	0.0629	0.7951
3911300321	OH	Montgomer	winter	so4	0.2613	0.8598
3911300321	OH	Montgomer	winter	no3	0.2407	1.029
3911300321	OH	Montgomer	winter	ocm	0.1954	0.9442
3911300321	OH	Montgomer	winter	ec	0.036	0.8746
3911300321	OH	Montgomer	winter	soil	0.0259	1.1295
3911300321	OH	Montgomer	winter	nh4	0.1531	0.9304
3911300321	OH	Montgomer	winter	pbw	0.0876	0.9205
3911300321	OH	Montgomer	spring	so4	0.3659	0.6606
3911300321	OH	Montgomer	spring	no3	0.0163	0.8639
3911300321	OH	Montgomer	spring	ocm	0.1895	1.0976
3911300321	OH	Montgomer	spring	ec	0.0442	0.9417
3911300321	OH	Montgomer	spring	soil	0.0253	1.0873
3911300321	OH	Montgomer	spring	nh4	0.1313	0.7149
3911300321	OH	Montgomer	spring	pbw	0.1326	0.6839
3911300321	OH	Montgomer	summer	so4	0.375	0.6234
3911300321	OH	Montgomer	summer	no3	0	0.9474
3911300321	OH	Montgomer	summer	ocm	0.128	1.1047
3911300321	OH	Montgomer	summer	ec	0.029	0.9496
3911300321	OH	Montgomer	summer	soil	0.0205	1.1299
3911300321	OH	Montgomer	summer	nh4	0.1114	0.6931
3911300321	OH	Montgomer	summer	pbw	0.1114	0.6482
3911300321	OH	Montgomer	fall	so4	0.3062	0.8033
3911300321	OH	Montgomer	fall	no3	0.1012	0.9634
3911300321	OH	Montgomer	fall	ocm	0.2221	1.0158
3911300321	OH	Montgomer	fall	ec	0.0514	0.877
3911300321	OH	Montgomer	fall	soil	0.028	1.1391
3911300321	OH	Montgomer	fall	nh4	0.1352	0.8625
3911300321	OH	Montgomer	fall	pbw	0.0982	0.8475

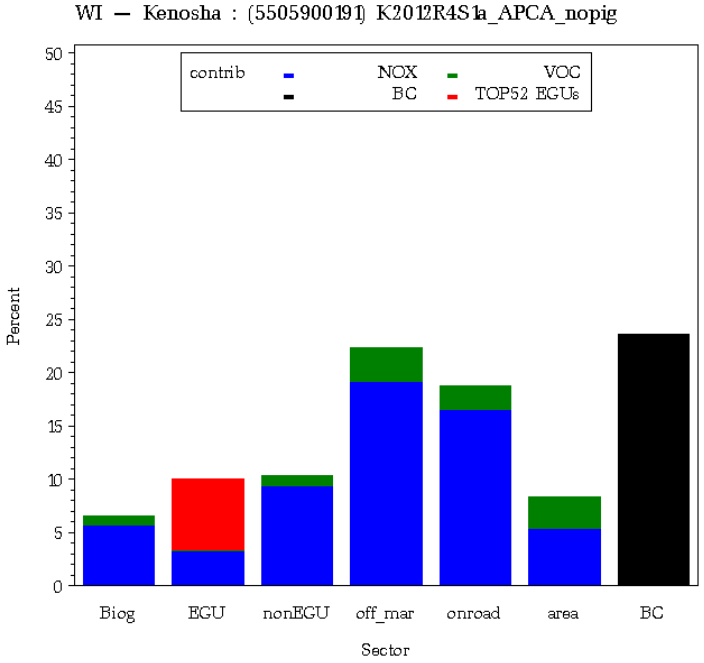
Site ID	State	County	Season	Species	Species Comp. of Ave. FRM (fraction)	Species RRF
3915100171	OH	Stark	winter	so4	0.2362	0.8558
3915100171	OH	Stark	winter	no3	0.2234	1.0222
3915100171	OH	Stark	winter	ocm	0.2478	0.9255
3915100171	OH	Stark	winter	ec	0.0414	0.8866
3915100171	OH	Stark	winter	soil	0.0334	1.099
3915100171	OH	Stark	winter	nh4	0.1376	0.925
3915100171	OH	Stark	winter	pbw	0.0802	0.9155
3915100171	OH	Stark	spring	so4	0.3581	0.6834
3915100171	OH	Stark	spring	no3	0.0236	0.855
3915100171	OH	Stark	spring	ocm	0.221	1.0892
3915100171	OH	Stark	spring	ec	0.0501	1.0017
3915100171	OH	Stark	spring	soil	0.058	1.0528
3915100171	OH	Stark	spring	nh4	0.1288	0.7264
3915100171	OH	Stark	spring	pbw	0.1256	0.7009
3915100171	OH	Stark	summer	so4	0.3621	0.6277
3915100171	OH	Stark	summer	no3	0	0.8203
3915100171	OH	Stark	summer	ocm	0.1483	1.0984
3915100171	OH	Stark	summer	ec	0.0403	1.016
3915100171	OH	Stark	summer	soil	0.037	1.0781
3915100171	OH	Stark	summer	nh4	0.1157	0.6739
3915100171	OH	Stark	summer	pbw	0.124	0.651
3915100171	OH	Stark	fall	so4	0.2293	0.8041
3915100171	OH	Stark	fall	no3	0.1262	0.9363
3915100171	OH	Stark	fall	ocm	0.2722	1.0226
3915100171	OH	Stark	fall	ec	0.0545	0.9202
3915100171	OH	Stark	fall	soil	0.0461	1.0959
3915100171	OH	Stark	fall	nh4	0.1105	0.8549
3915100171	OH	Stark	fall	pbw	0.0706	0.8428
3915300171	OH	Summit	winter	so4	0.2511	0.8771
3915300171	OH	Summit	winter	no3	0.2376	1.0052
3915300171	OH	Summit	winter	ocm	0.2185	0.9429
3915300171	OH	Summit	winter	ec	0.0334	0.8677
3915300171	OH	Summit	winter	soil	0.0255	1.0835
3915300171	OH	Summit	winter	nh4	0.1489	0.9374
3915300171	OH	Summit	winter	pbw	0.0851	0.945
3915300171	OH	Summit	spring	so4	0.387	0.7046
3915300171	OH	Summit	spring	no3	0.0072	0.8466
3915300171	OH	Summit	spring	ocm	0.1901	1.0967
3915300171	OH	Summit	spring	ec	0.035	0.9482
3915300171	OH	Summit	spring	soil	0.0304	1.0524
3915300171	OH	Summit	spring	nh4	0.1294	0.7521
3915300171	OH	Summit	spring	pbw	0.1342	0.7384
3915300171	OH	Summit	summer	so4	0.3694	0.6378
3915300171	OH	Summit	summer	no3	0	0.8587
3915300171	OH	Summit	summer	ocm	0.1417	1.1077
3915300171	OH	Summit	summer	ec	0.0332	0.9506
3915300171	OH	Summit	summer	soil	0.0198	1.0744
3915300171	OH	Summit	summer	nh4	0.1121	0.6961
3915300171	OH	Summit	summer	pbw	0.1146	0.6691
3915300171	OH	Summit	fall	so4	0.2443	0.8074
3915300171	OH	Summit	fall	no3	0.1175	0.9392
3915300171	OH	Summit	fall	ocm	0.2636	1.0252
3915300171	OH	Summit	fall	ec	0.0623	0.8883
3915300171	OH	Summit	fall	soil	0.0494	1.086
3915300171	OH	Summit	fall	nh4	0.109	0.8622
3915300171	OH	Summit	fall	pbw	0.0723	0.8506

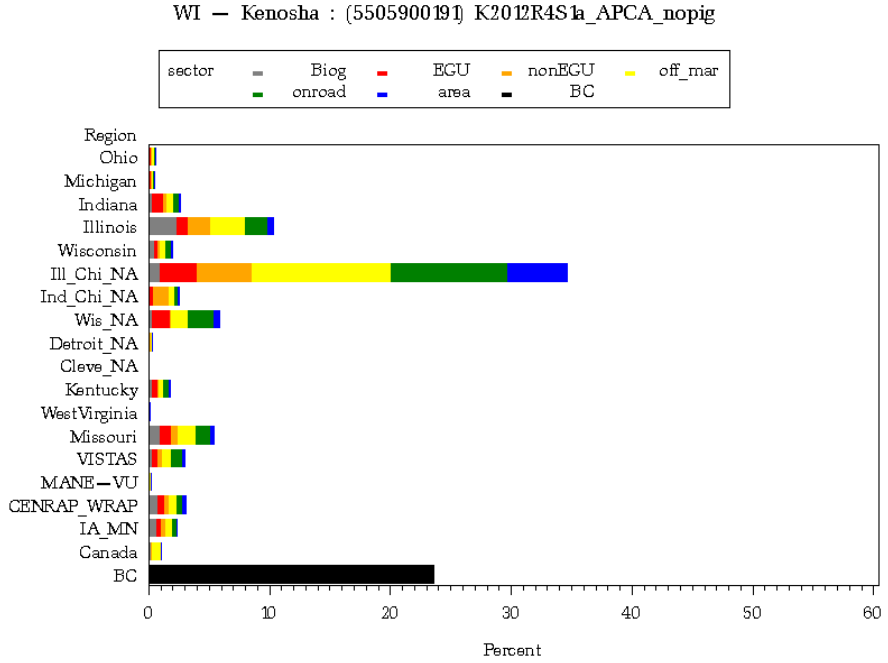
APPENDIX II

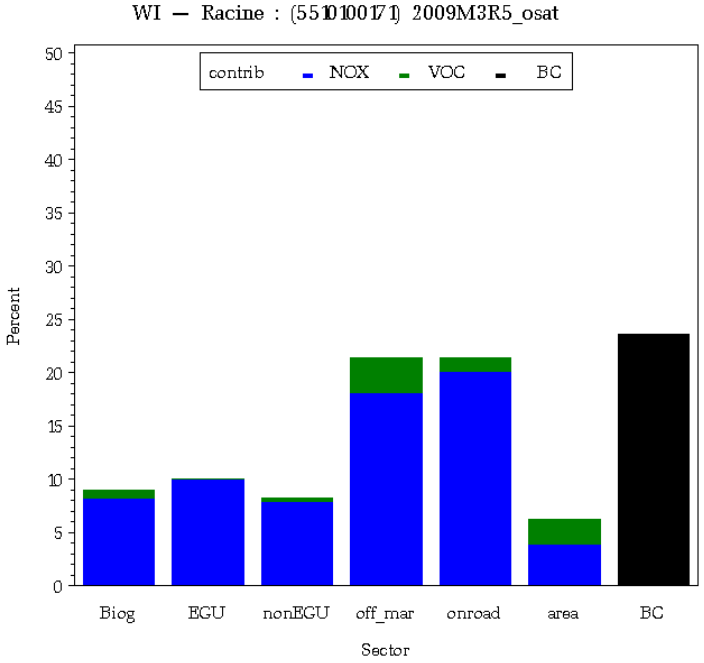
Ozone Source Apportionment Modeling Results

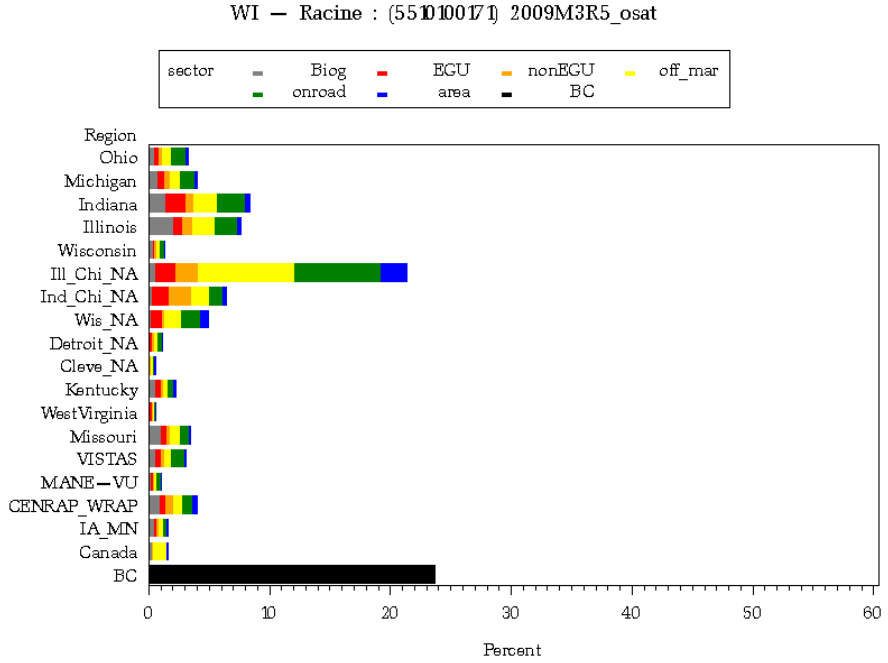

WI — Kenosha : (550590019) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector

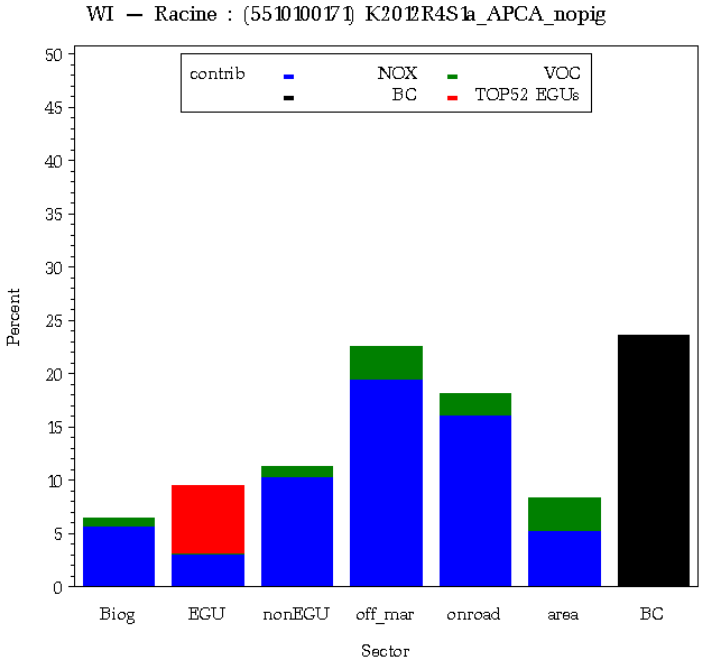

WI — Kenosha : (550590019) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

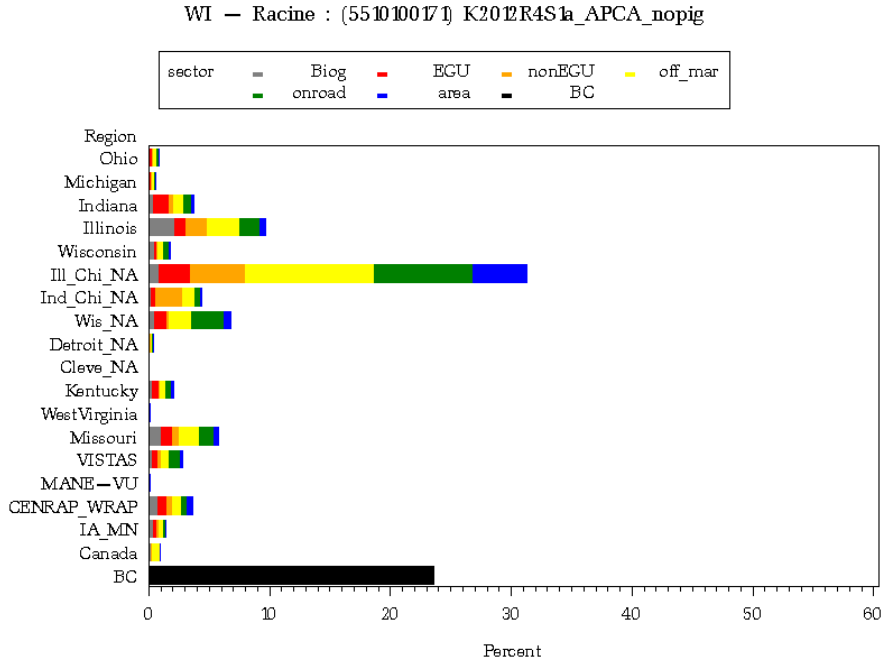

WI — Kenosha : (550590019) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector

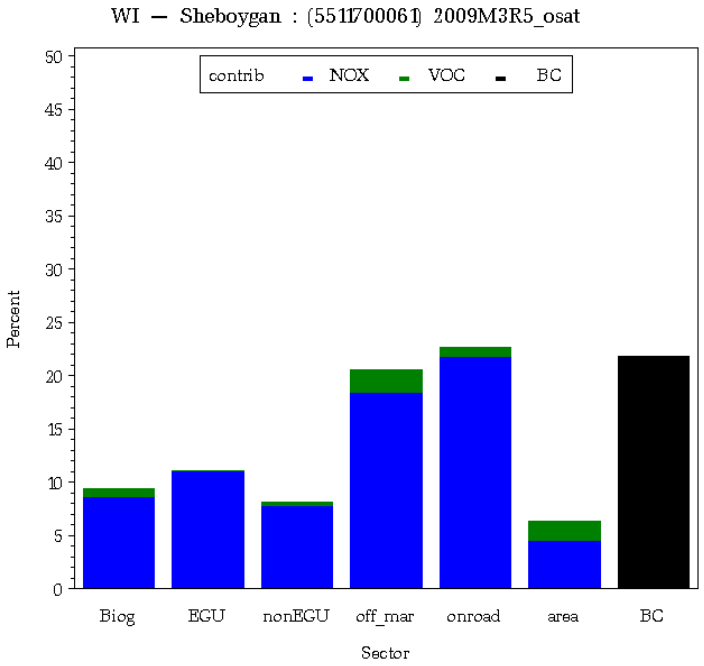

WI — Kenosha : (550590019) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

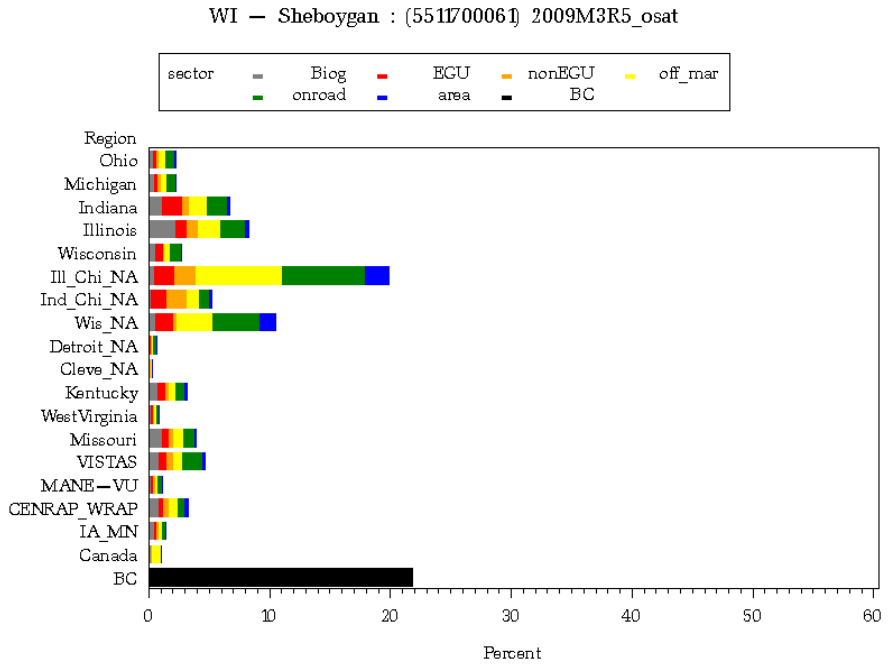

WI — Racine : (551010017) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

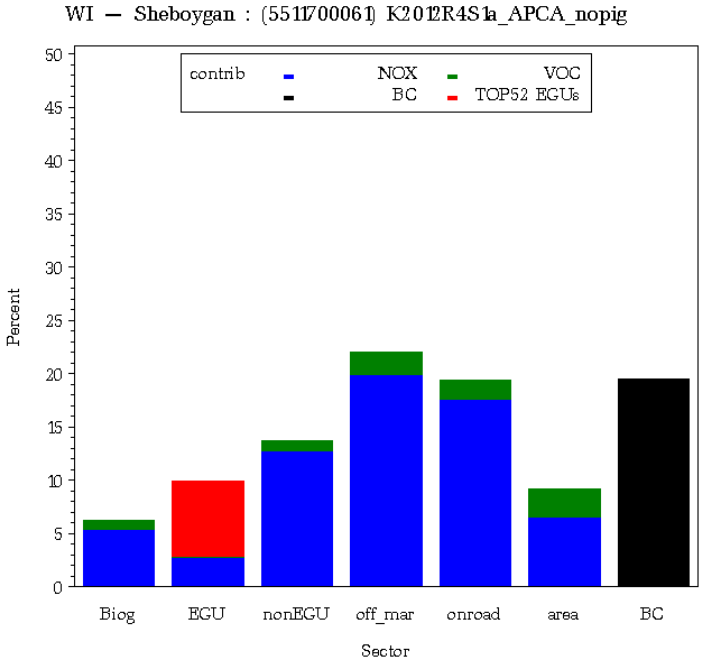

WI — Racine : (551010017) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

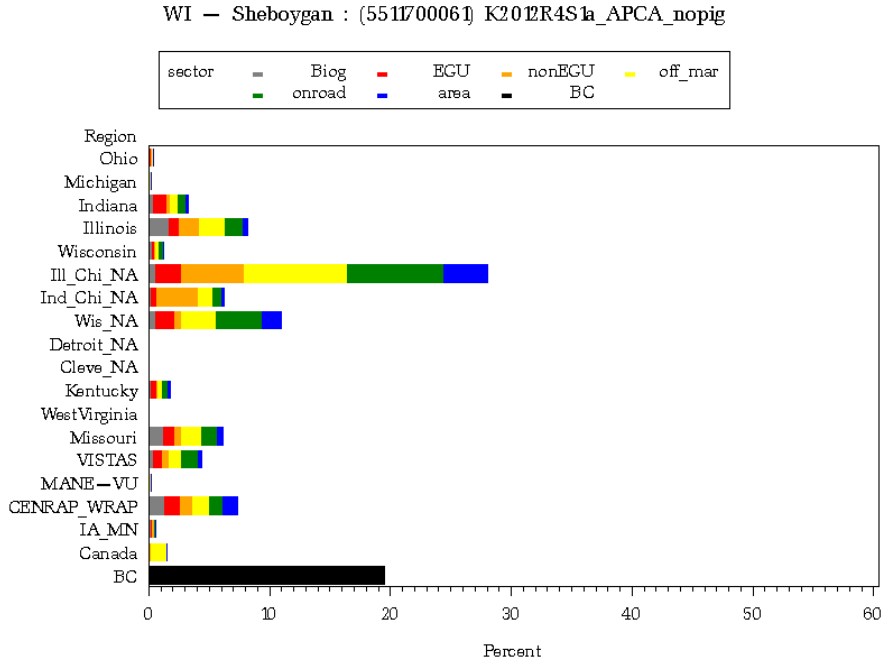

WI — Racine : (551010017) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

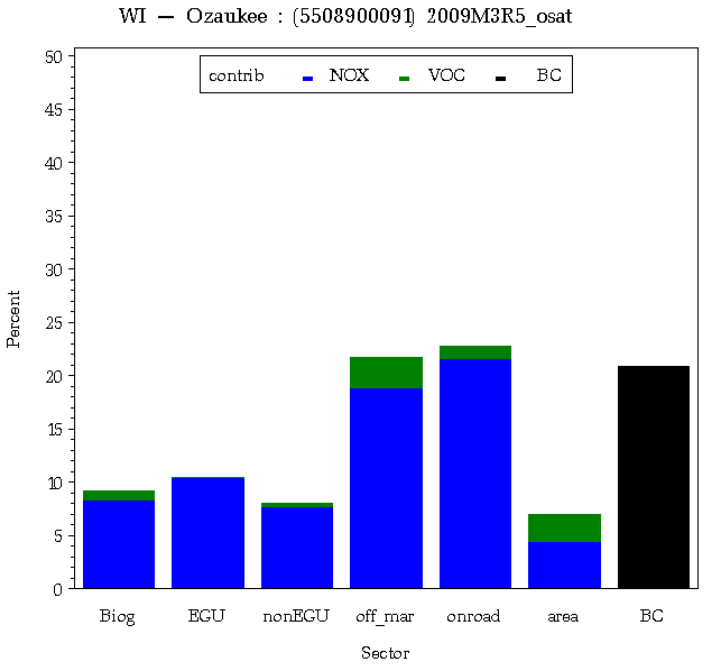

WI — Racine : (551010017) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

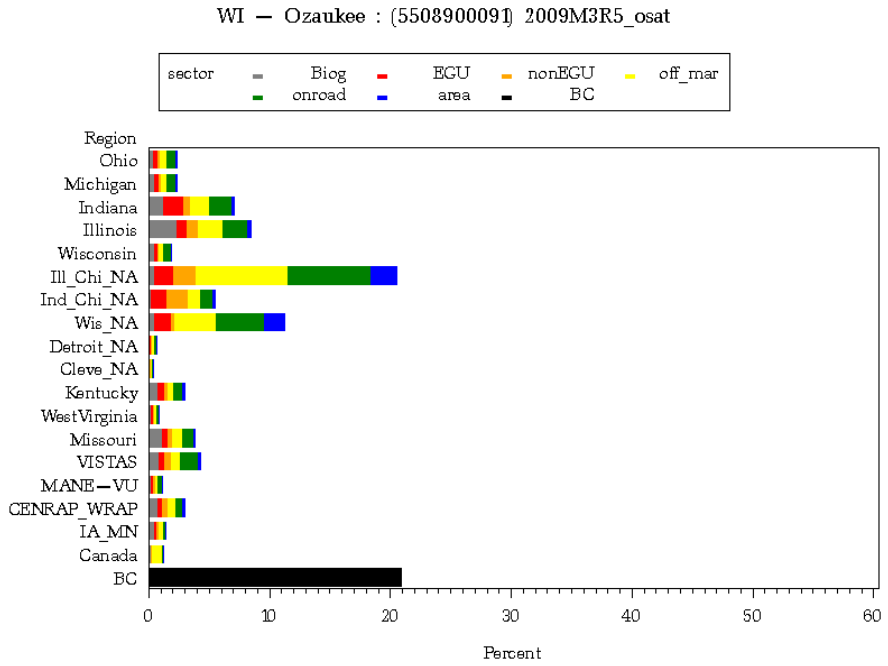

WI — Sheboygan : (551700061) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

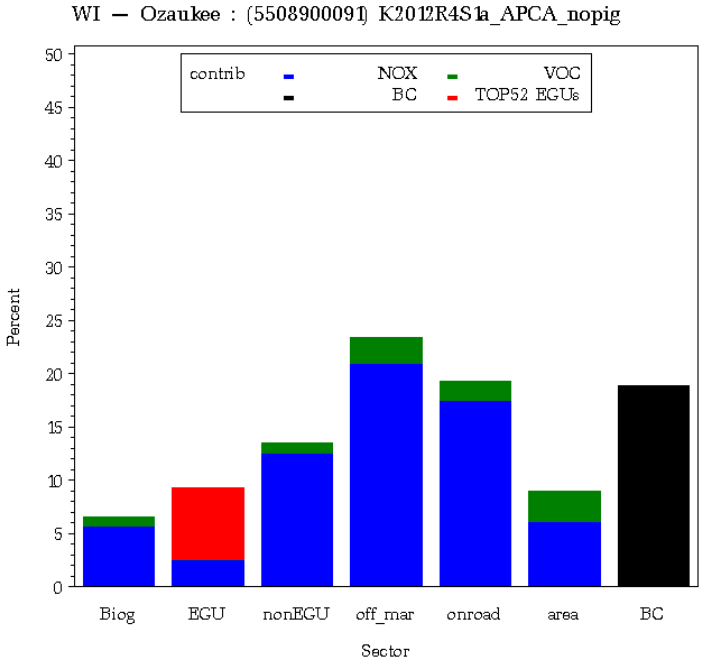

WI — Sheboygan : (551700061) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

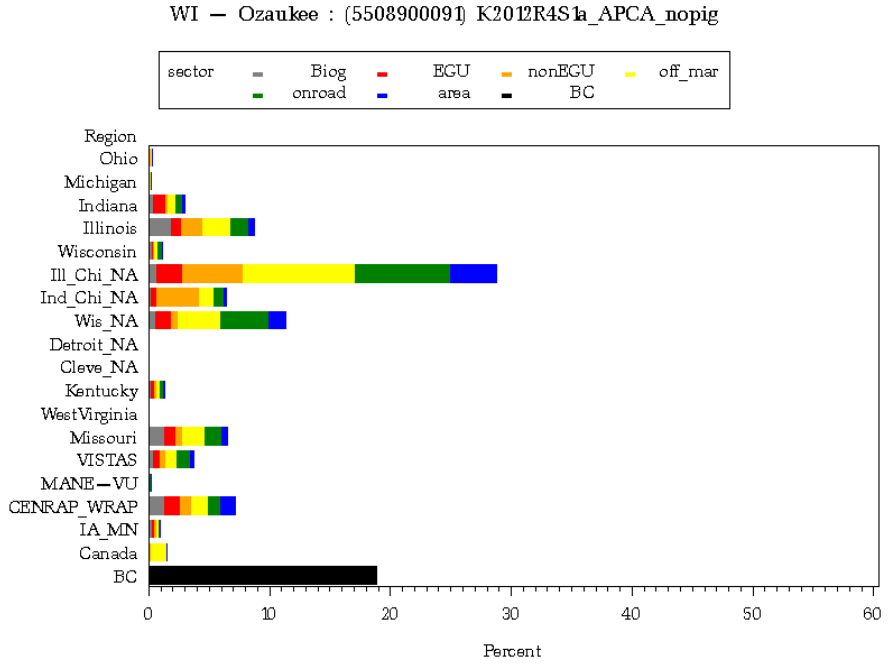

WI — Sheboygan : (551700061) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

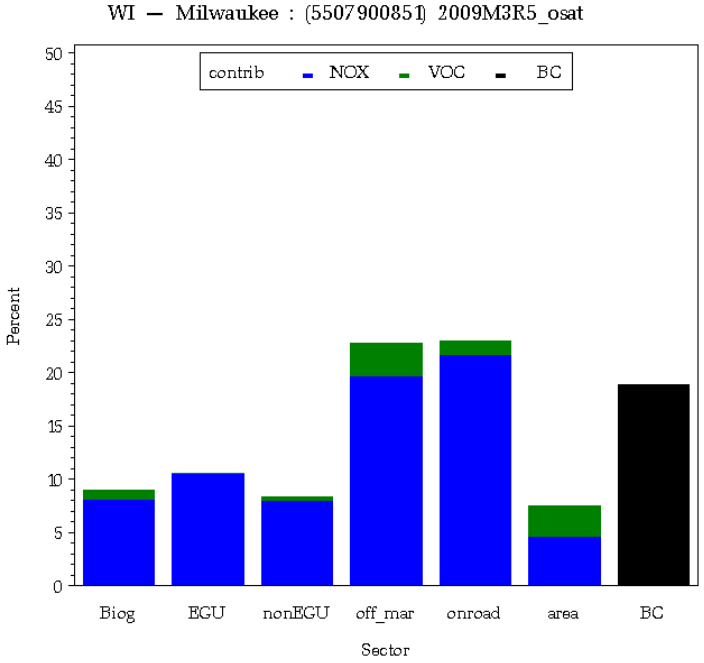

WI — Sheboygan : (551700061) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

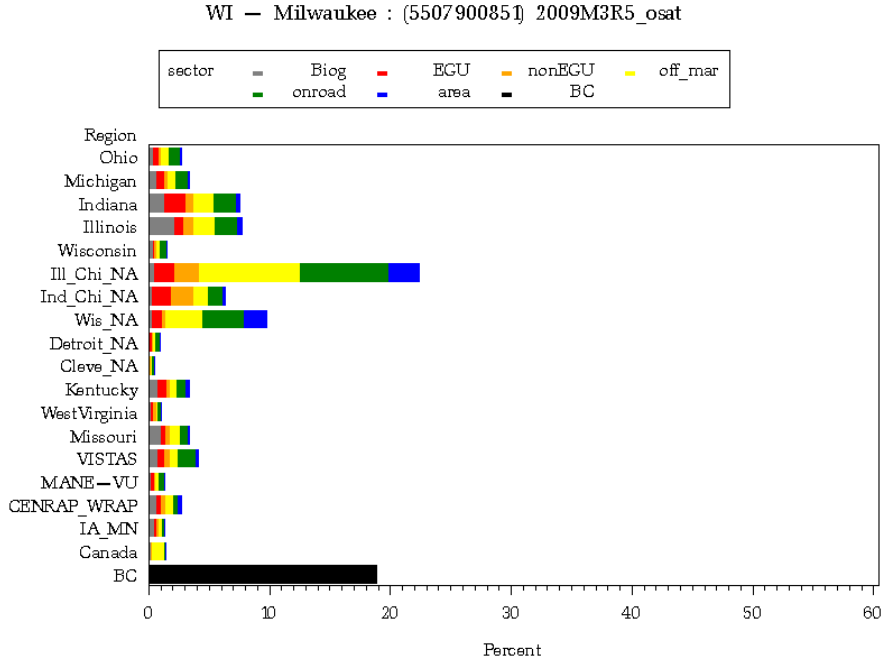

WI — Ozaukee : (5508900091) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Ozaukee : (5508900091) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Ozaukee : (5508900091) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Ozaukee : (5508900091) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Milwaukee : (550790085 1) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Milwaukee : (550790085 1) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
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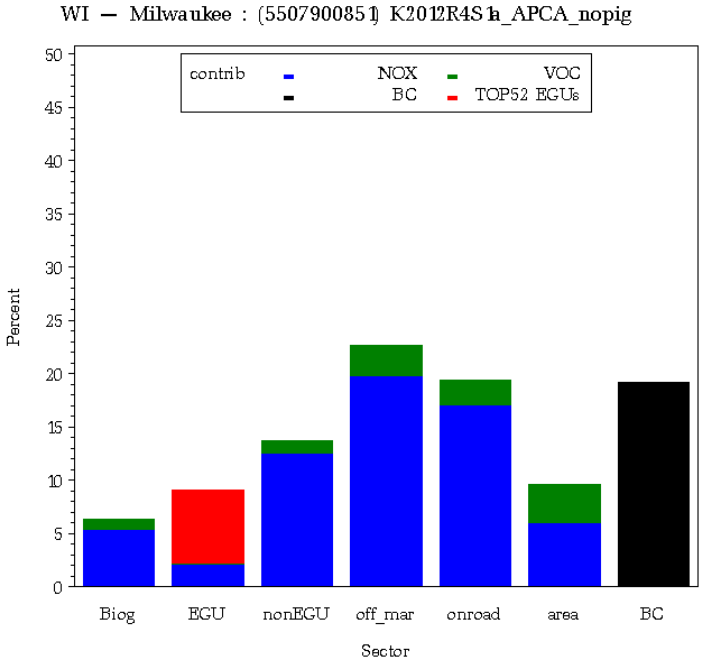
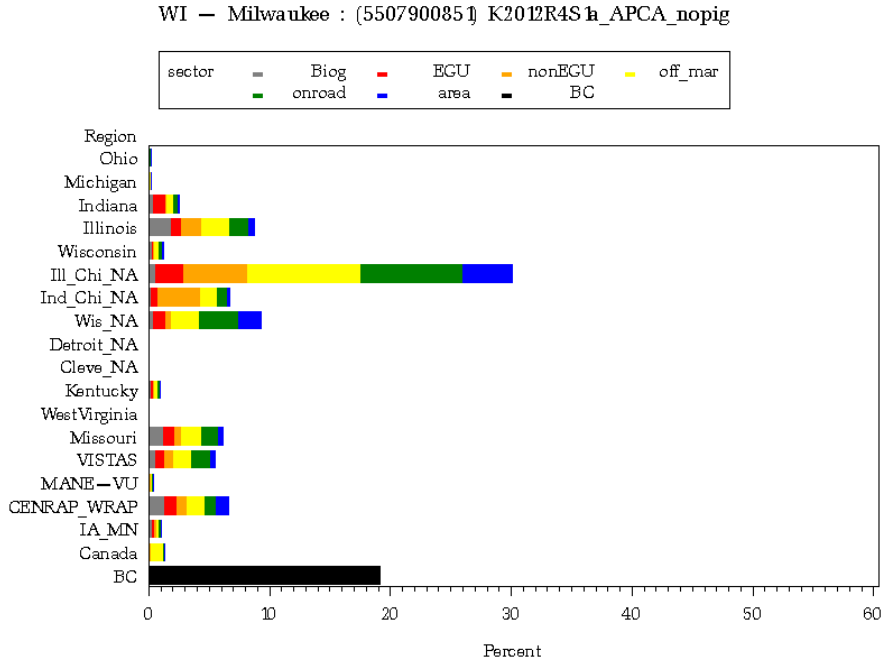
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Milwaukee : (550790085 1) K2012R4S ha_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Milwaukee : (550790085 1) K2012R4S ha_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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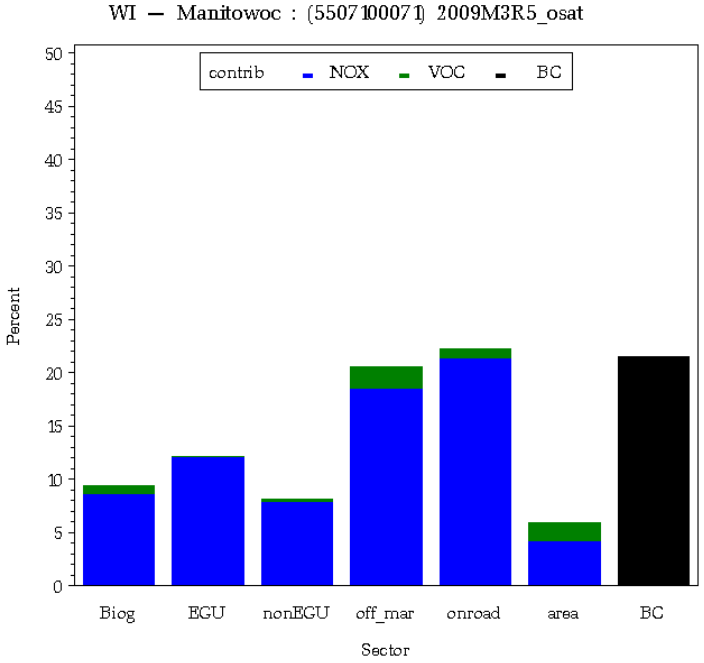
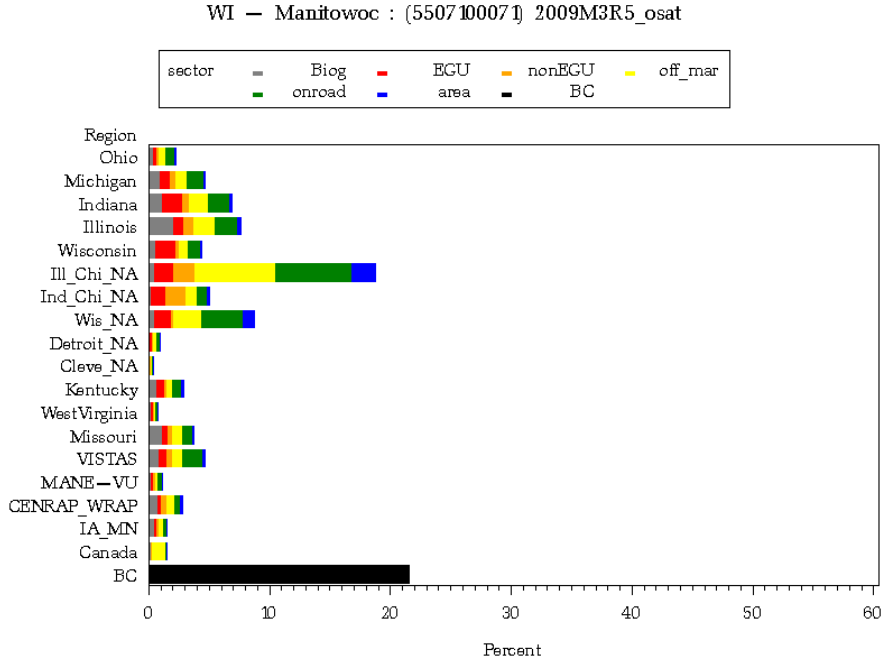
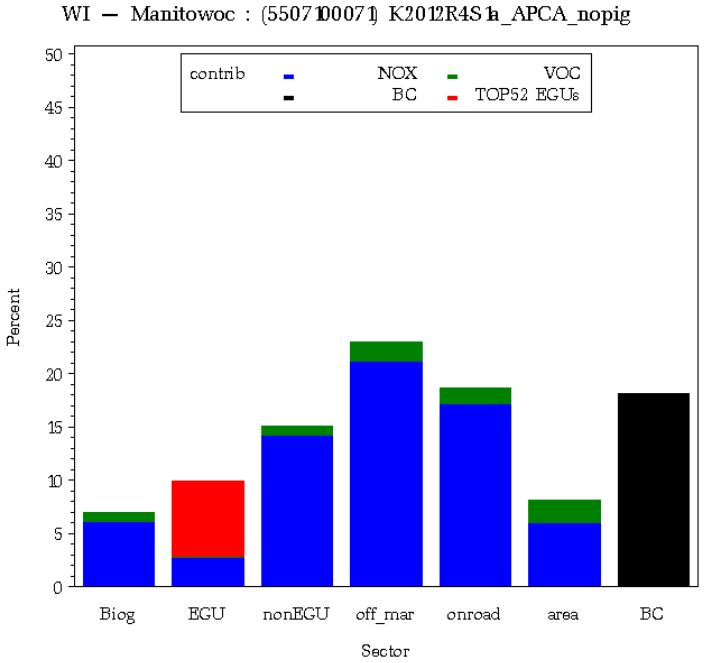
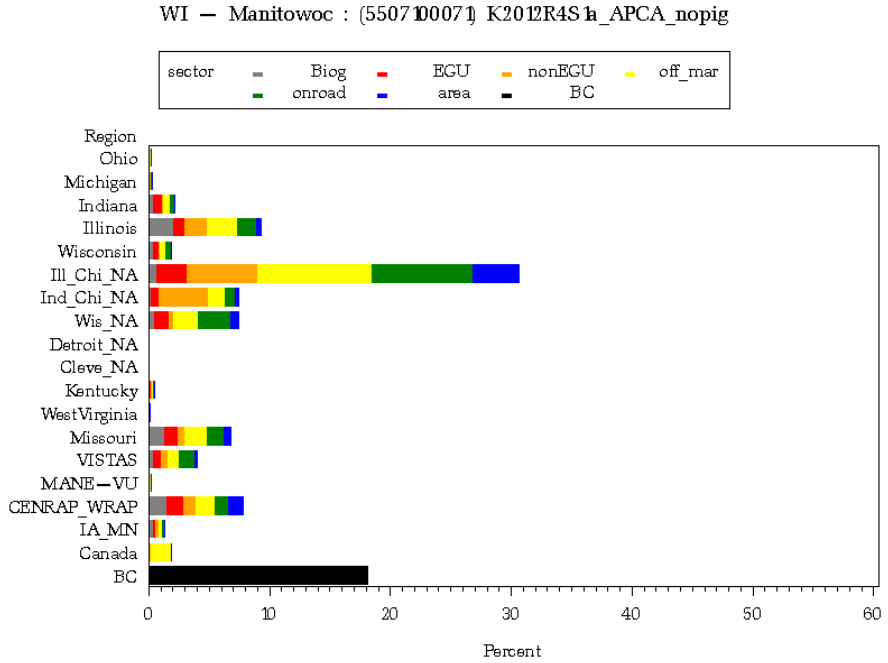
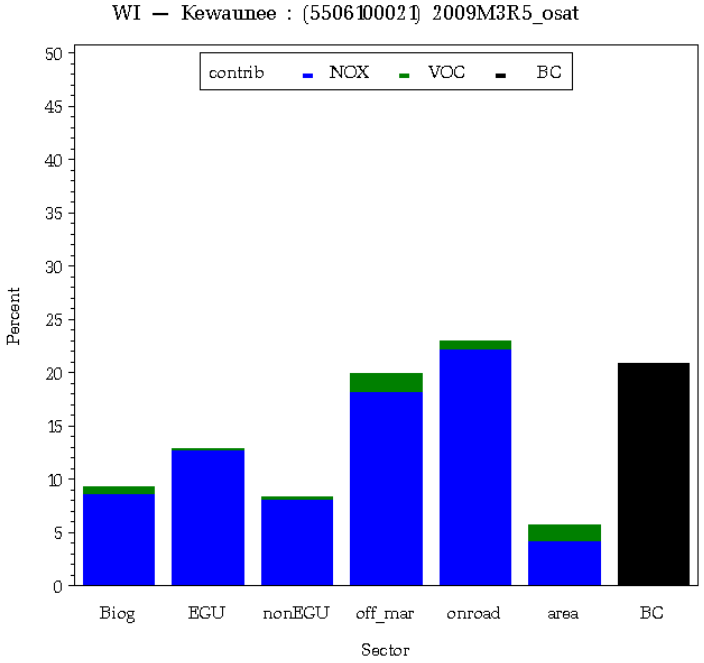
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

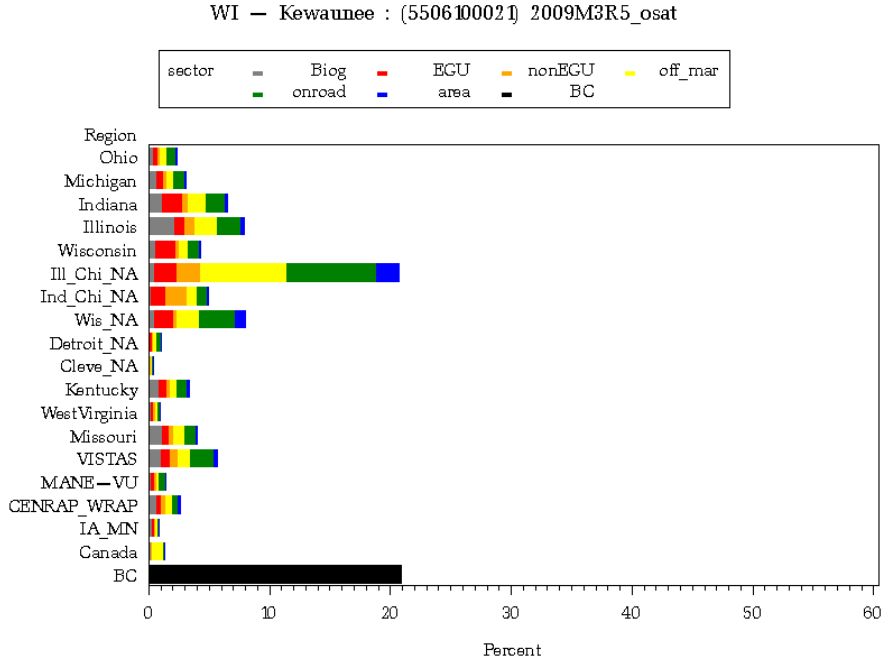

WI — Manitowoc : (550710071) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Manitowoc : (550710071) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Manitowoc : (550710071) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Manitowoc : (550710071) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Kewaunee : (550610002 1) 2009M3R5_osat
contrib NOX VOC BC
Percent
0 5 10 15 20 25 30 35 40 45 50
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Kewaunee : (550610002 1) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
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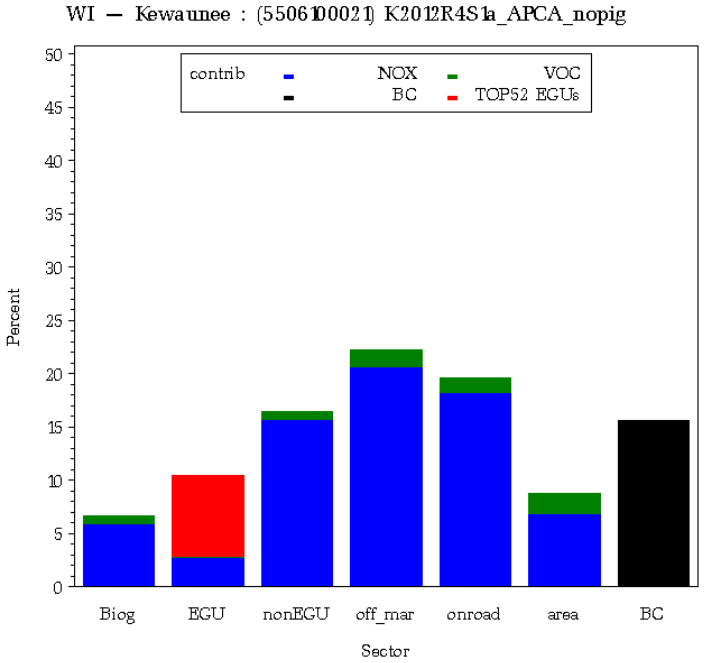
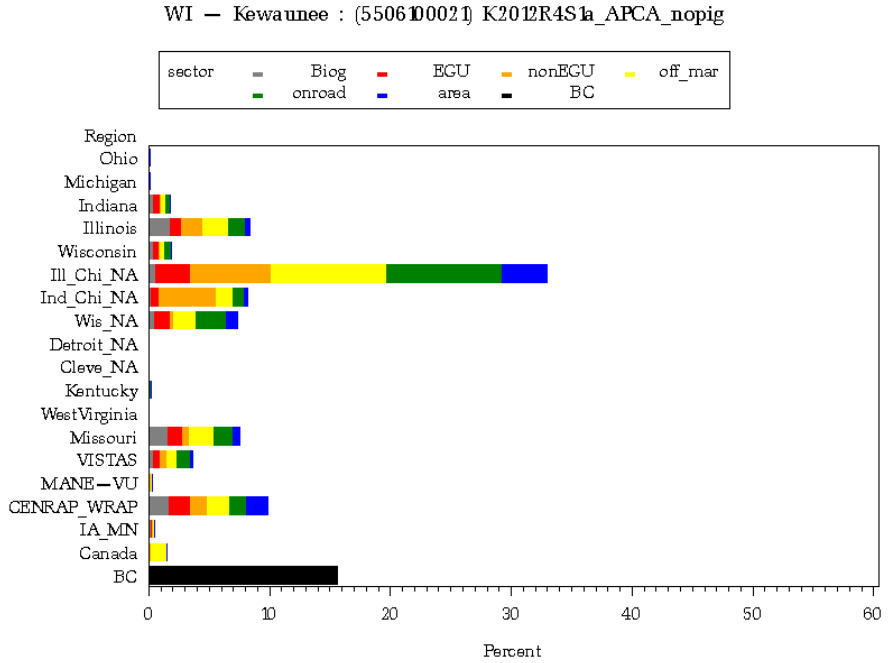
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0 10 20 30 40 50 60
Percent


WI — Kewaunee : (550610002 1) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
0 5 10 15 20 25 30 35 40 45 50
Biog EGU nonEGU off_mar onroad area BC
Sector


WI — Kewaunee : (550610002 1) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
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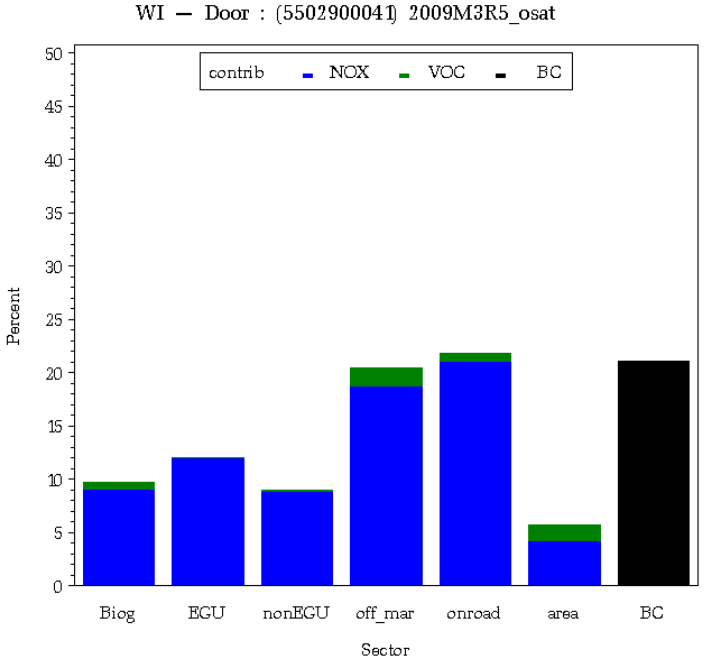
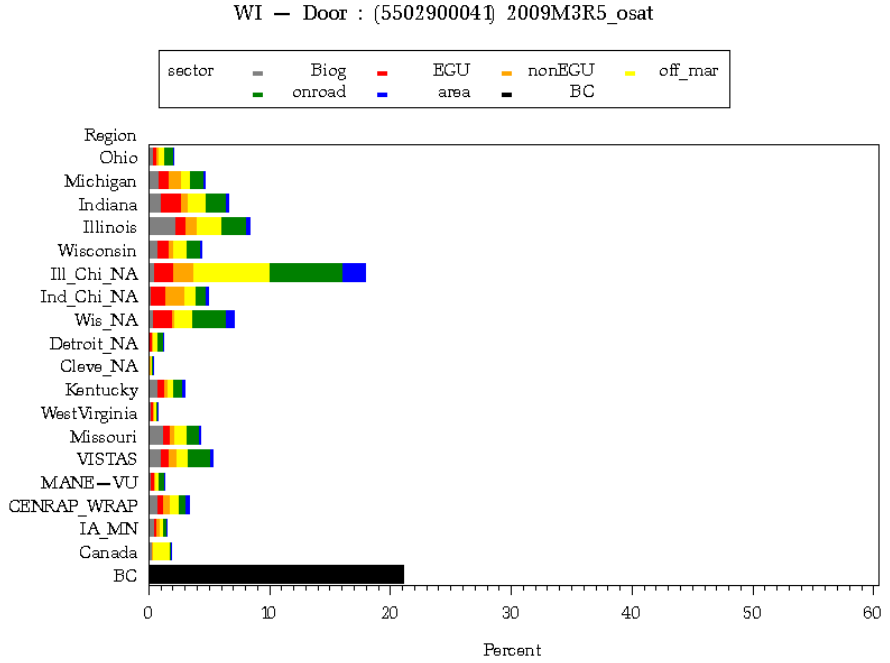
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0 10 20 30 40 50 60
Percent


WI — Door : (550290041) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Door : (550290041) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
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Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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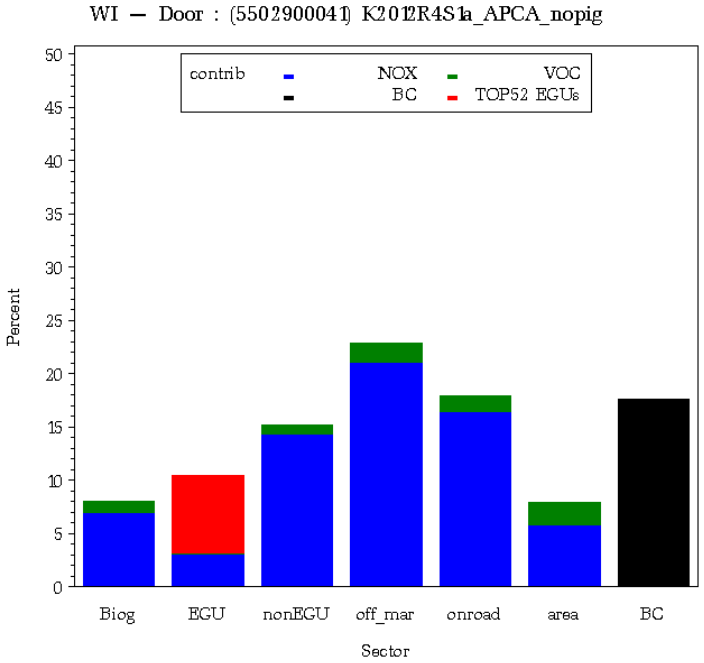
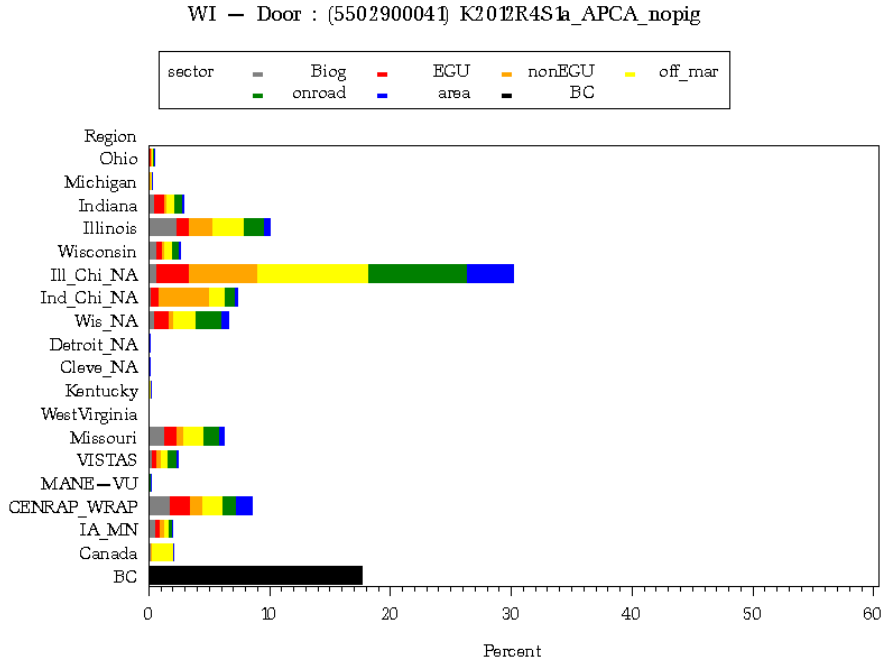
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


WI — Door : (550290041) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


WI — Door : (550290041) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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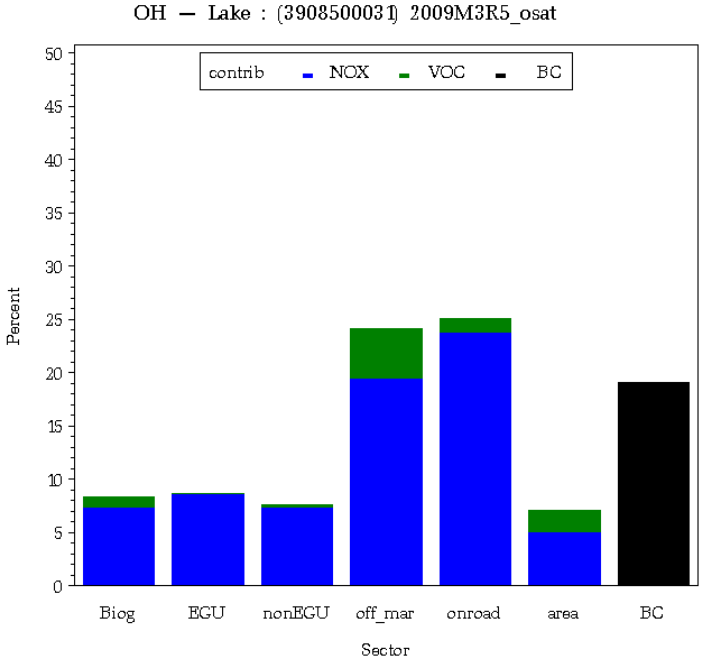
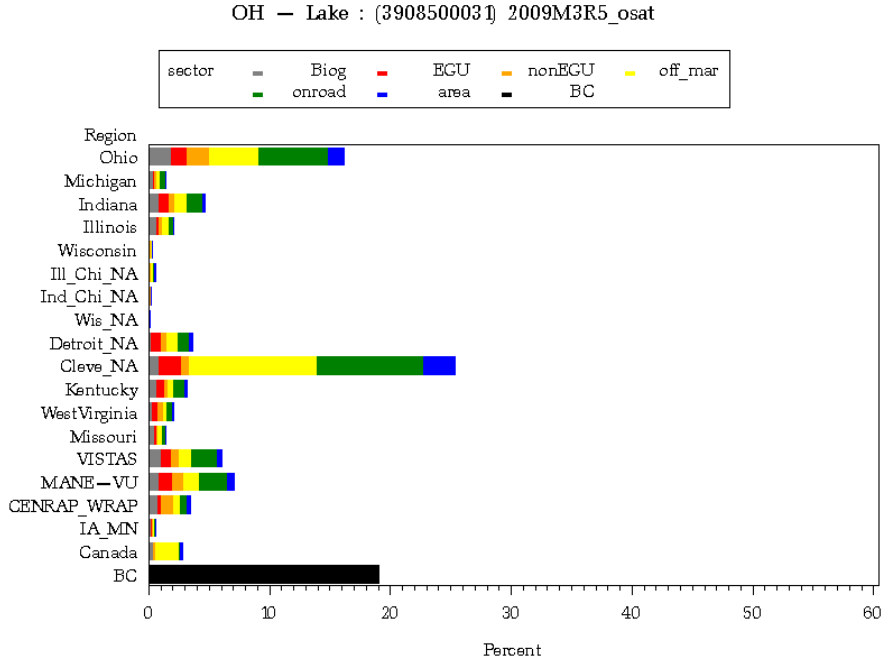
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Lake : (390850003) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


OH — Lake : (390850003) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
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Wisconsin
Ill_Chi_NA
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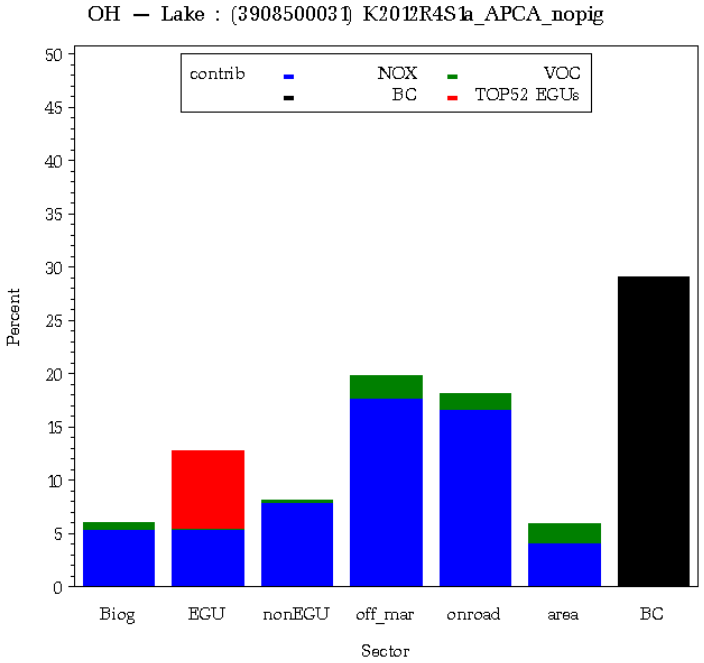
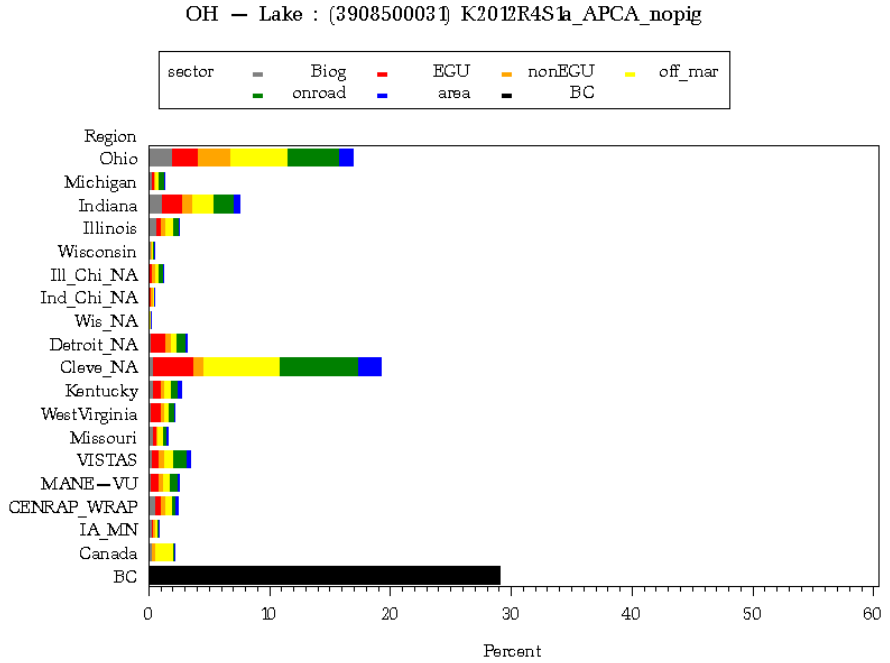
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Lake : (390850003) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


OH — Lake : (390850003) K2012R4S1a_APCA_nopig
sector
Biog
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nonEGU
off_mar
onroad
area
BC
Region
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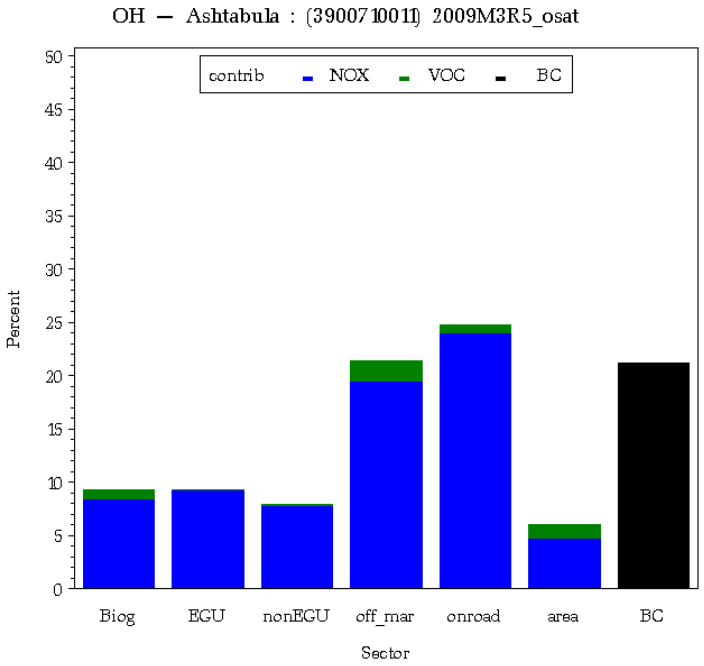
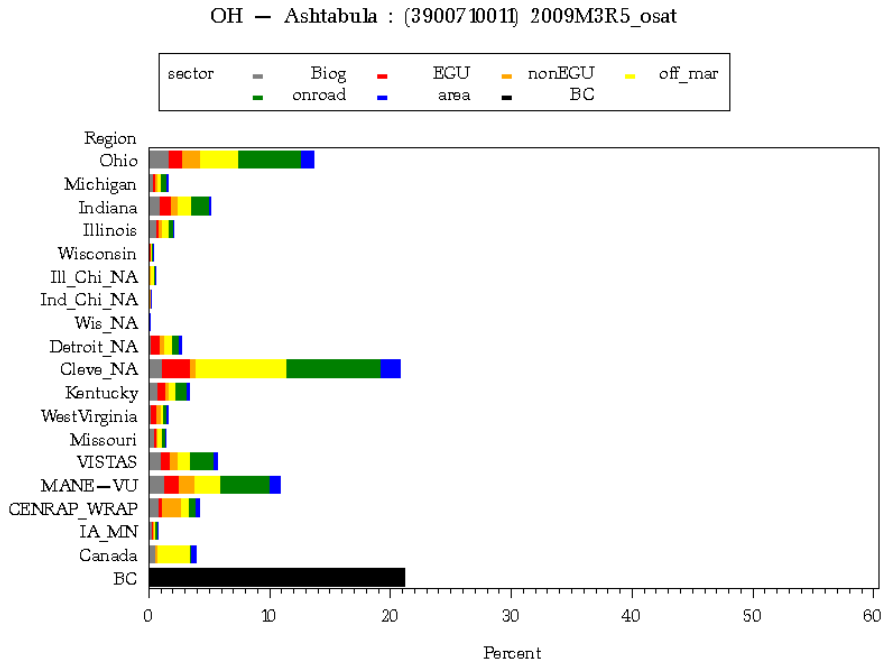
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Ashtabula : (390071001) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Ashtabula : (390071001) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
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Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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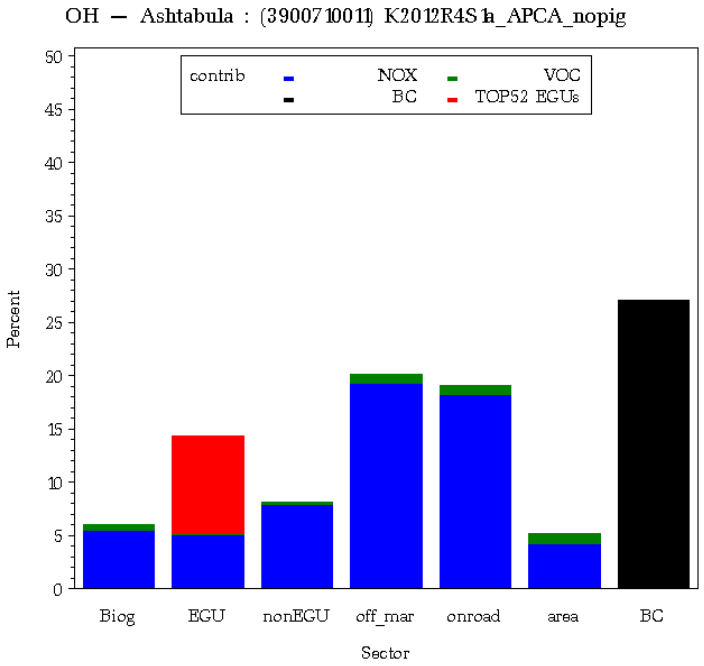
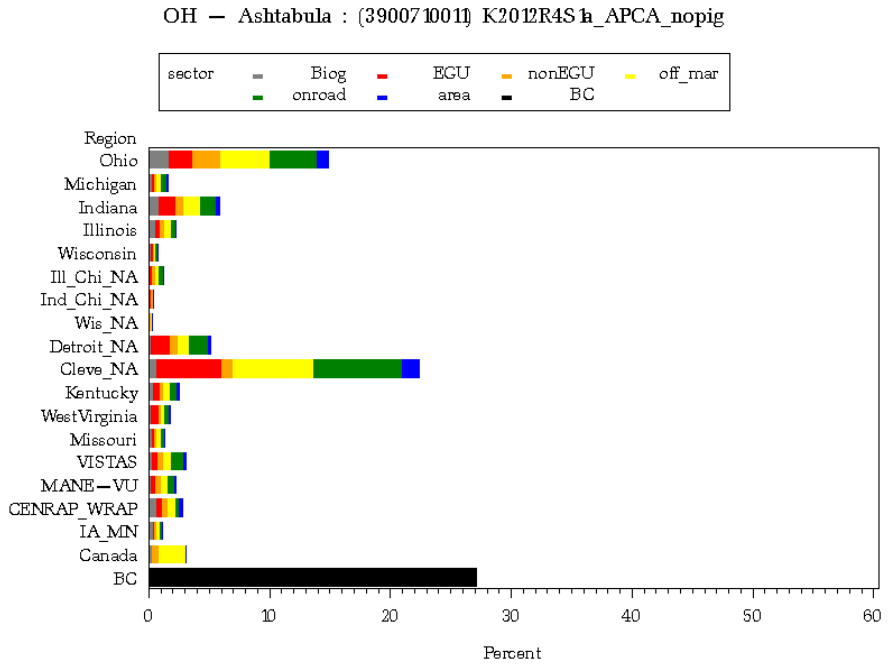
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


OH — Ashtabula : (390071001) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


OH — Ashtabula : (390071001) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
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Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
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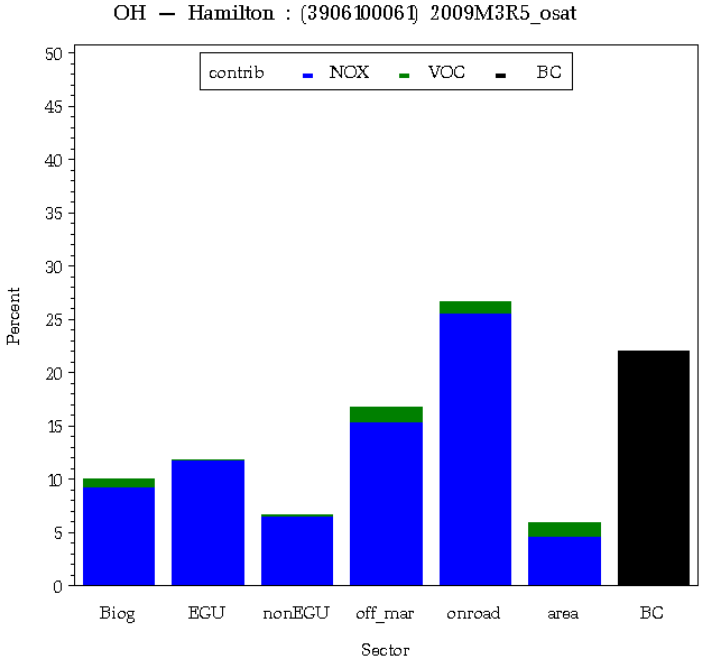
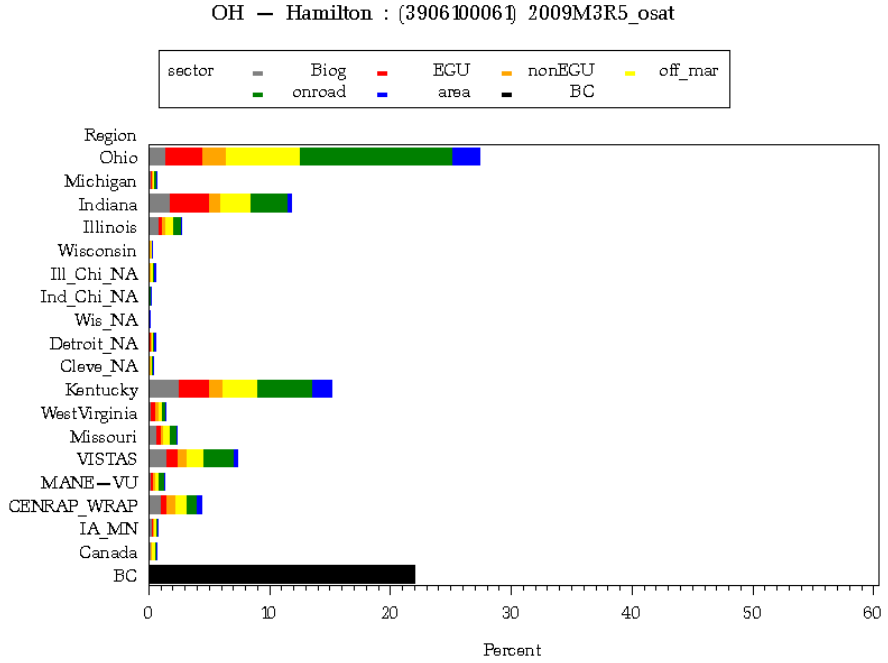
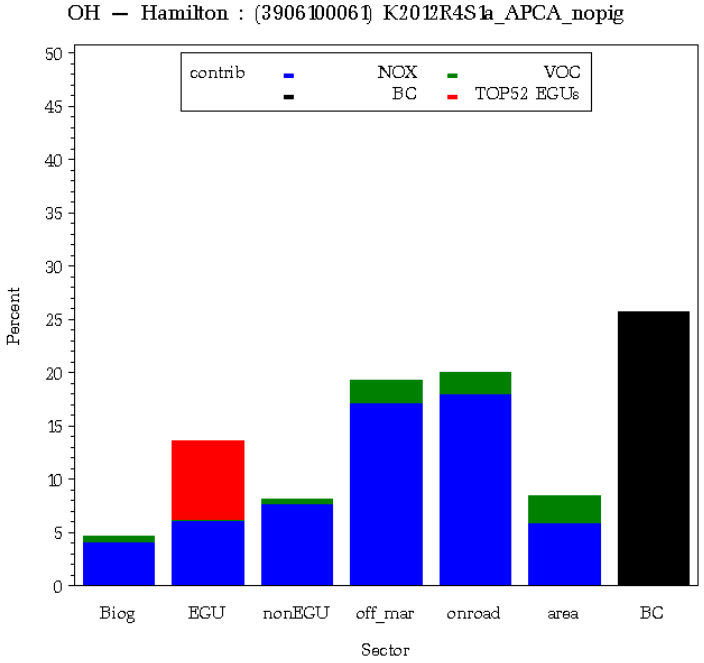
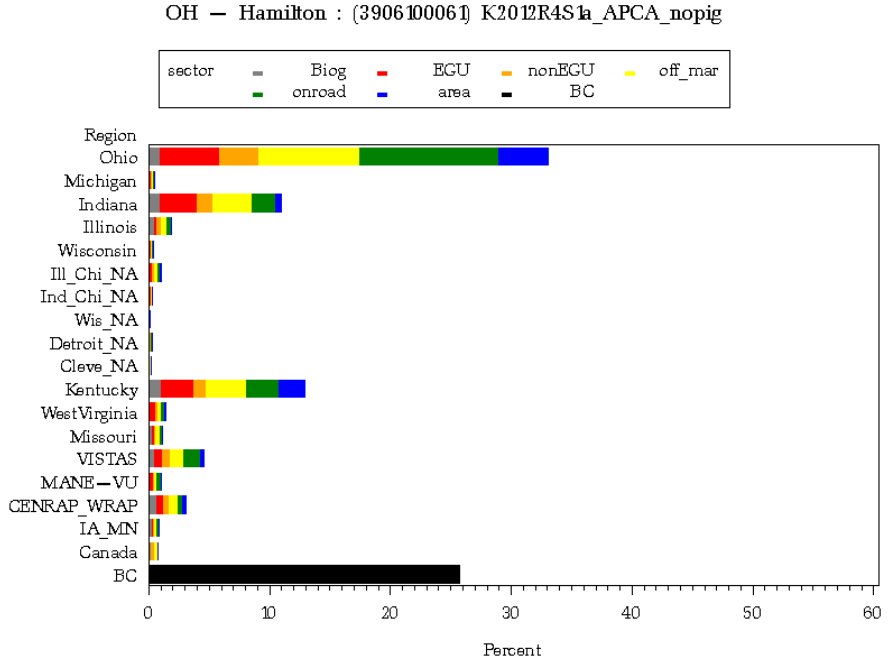
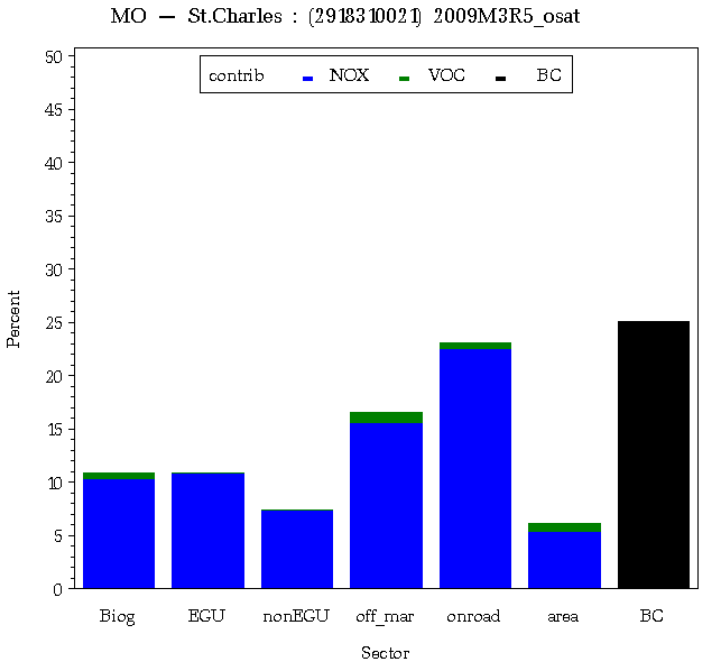
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

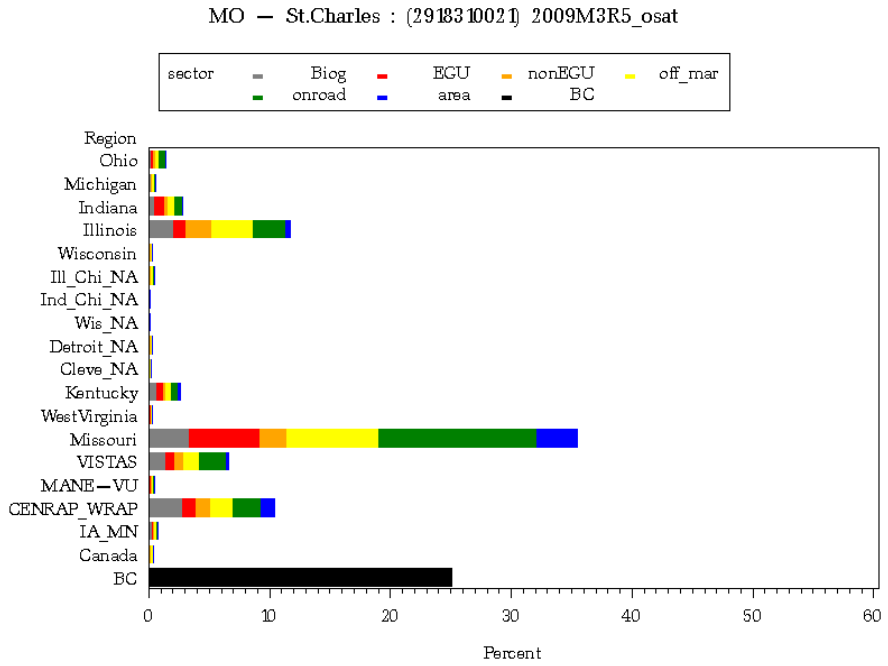

OH — Hamilton : (3906100061) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

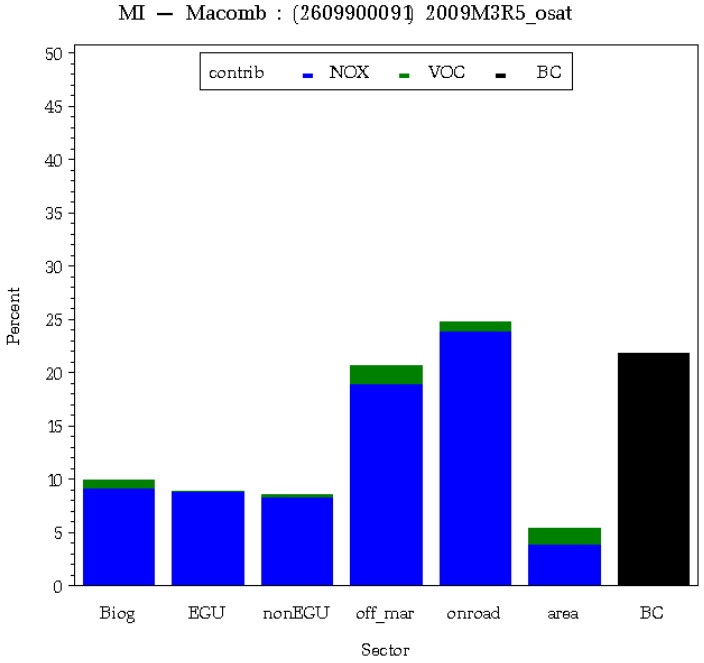

OH — Hamilton : (3906100061) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

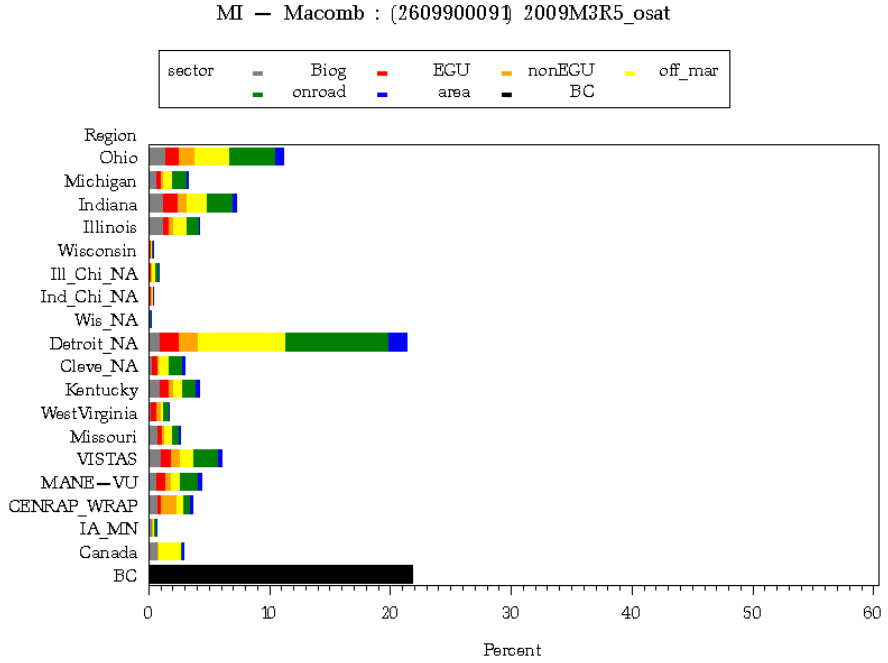

OH — Hamilton : (3906100061) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

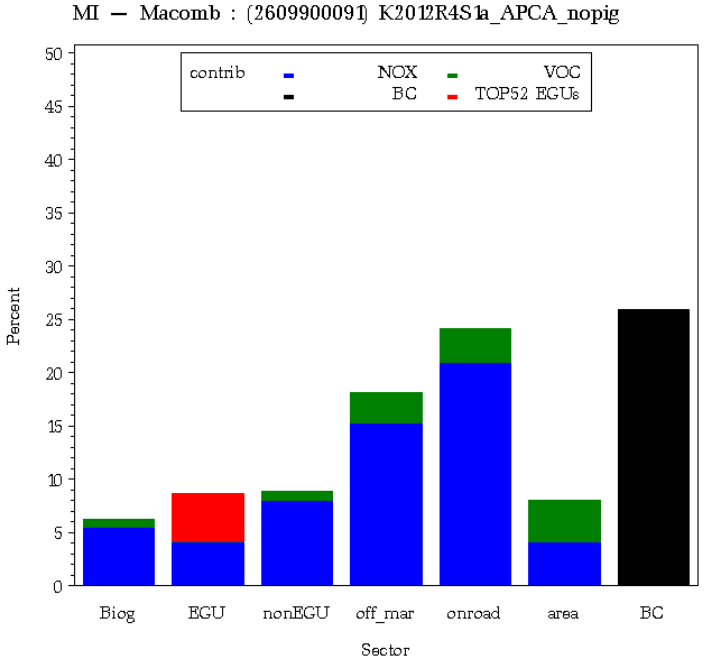

OH — Hamilton : (3906100061) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


MO — St.Charles : (291831002 1) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
0
5
10
15
20
25
30
35
40
45
50
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


MO — St.Charles : (291831002 1) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0
10
20
30
40
50
60
Percent


MI — Macomb : (2609900091) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector


MI — Macomb : (2609900091) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent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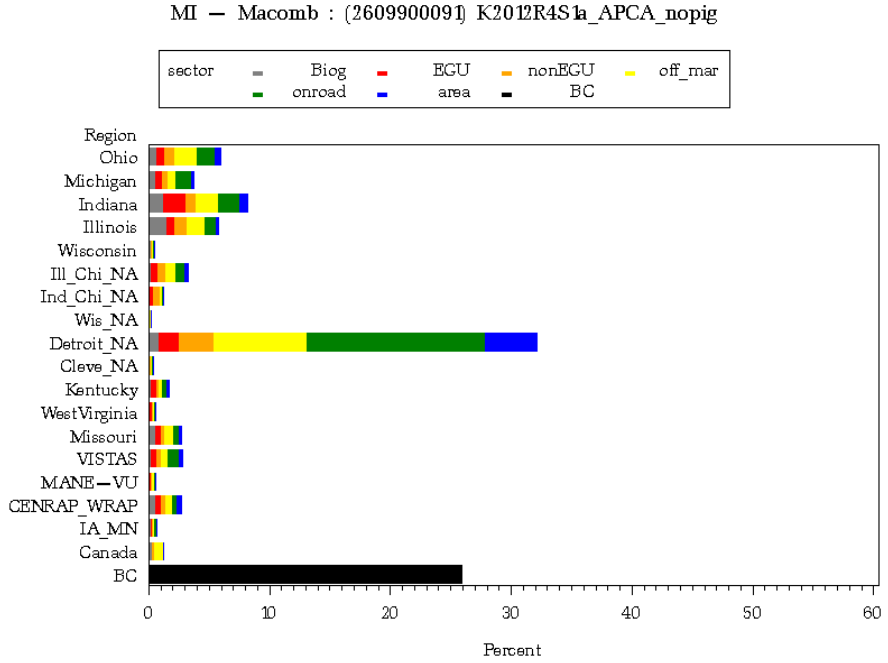
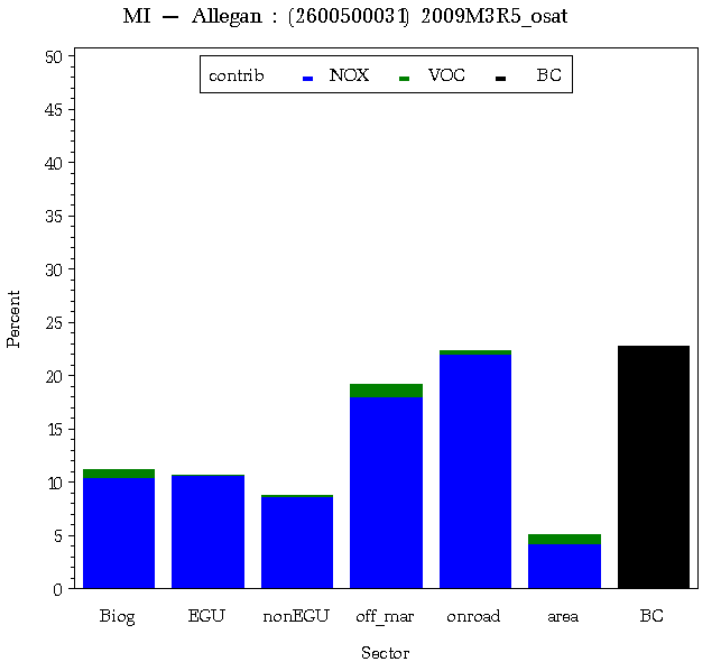
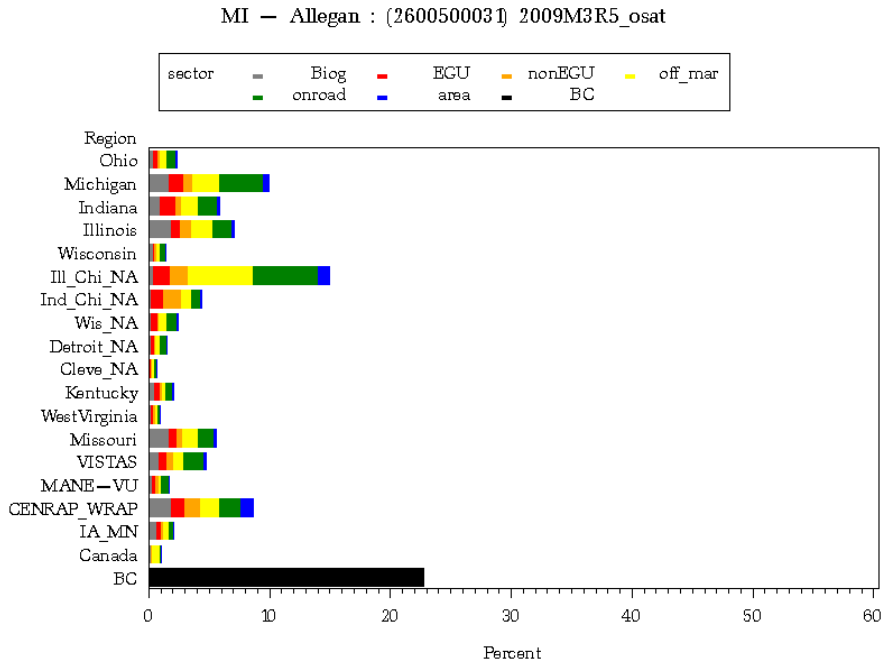
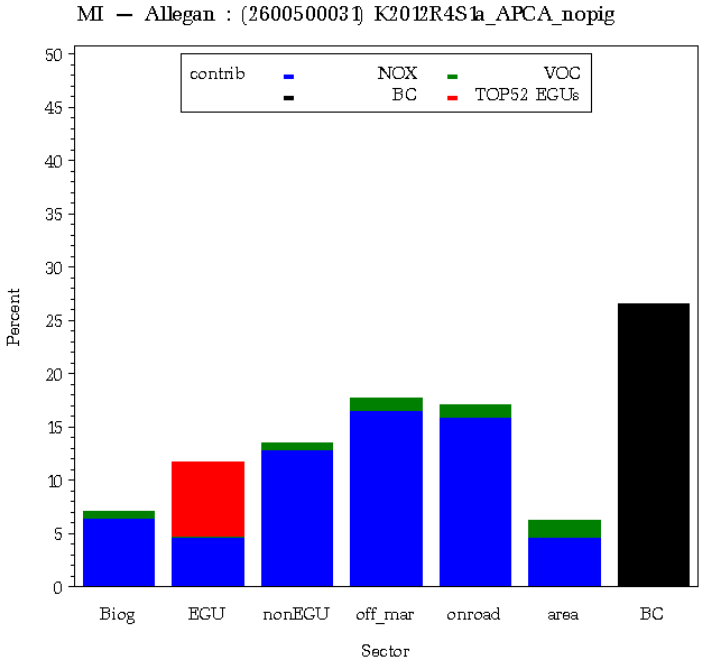
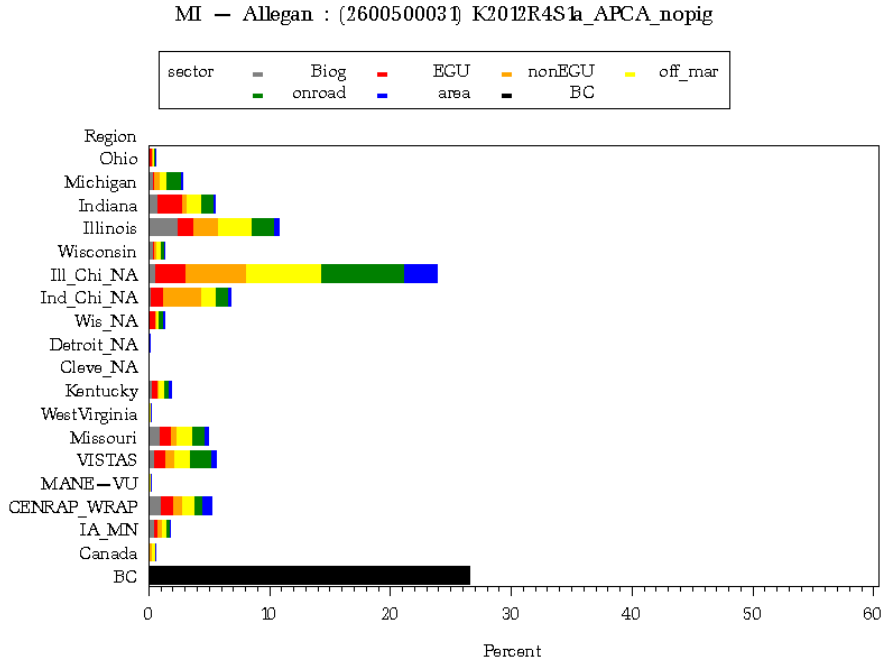
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

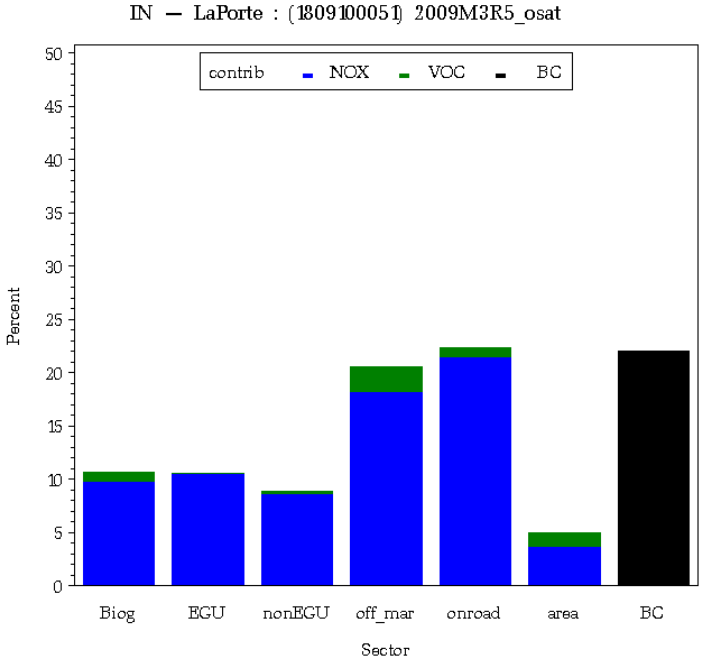

MI — Macomb : (2609900091) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

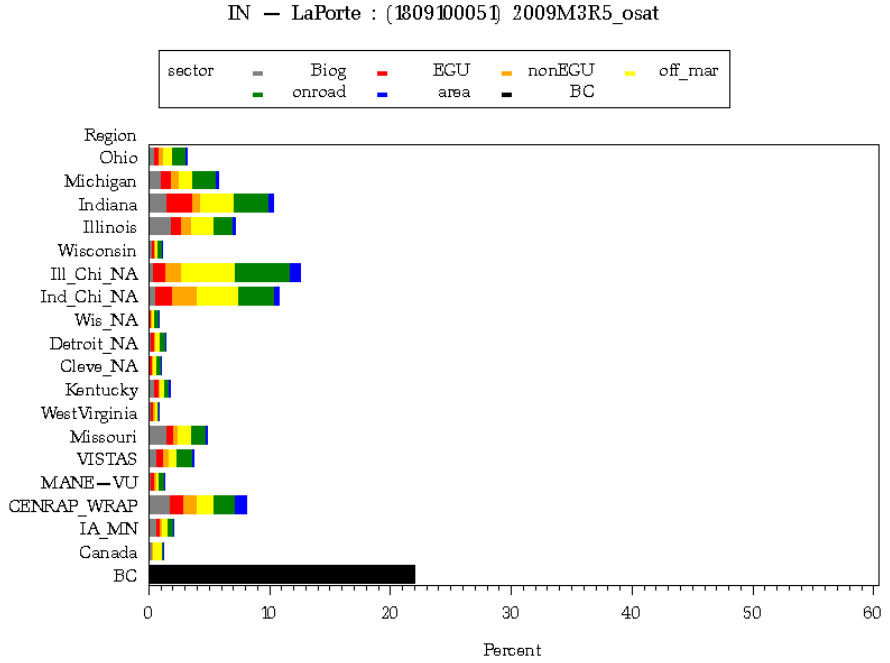

MI — Allegan : (2600500031) 2009M3R5_osat
contrib NOX VOC BC
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

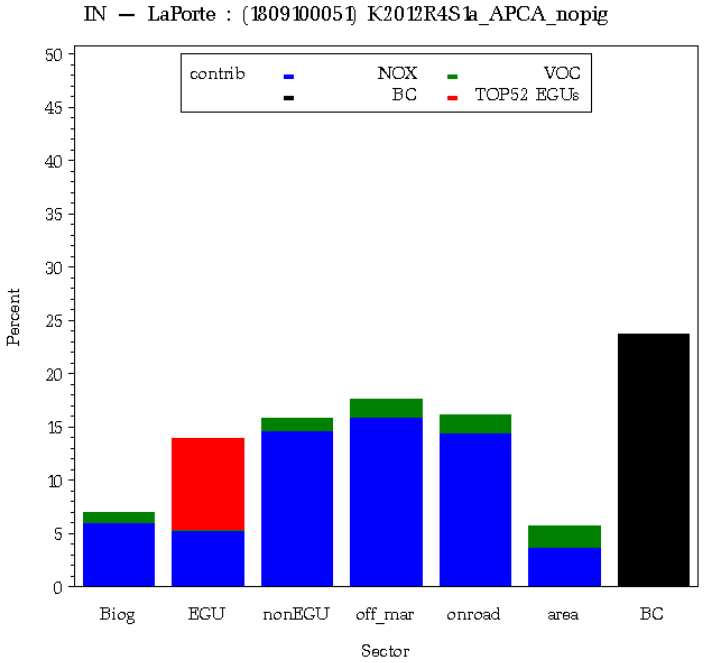

MI — Allegan : (2600500031) 2009M3R5_osat
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

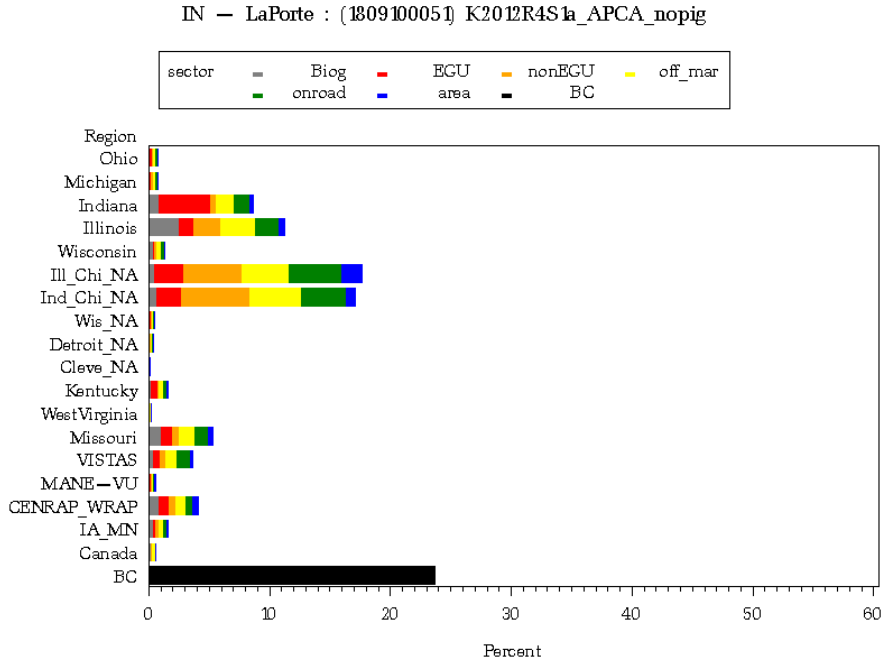

MI — Allegan : (2600500031) K2012R4S1a_APCA_nopig
contrib NOX VOC BC TOP52 EGUs
Percent
Biog EGU nonEGU off_mar onroad area BC
Sector

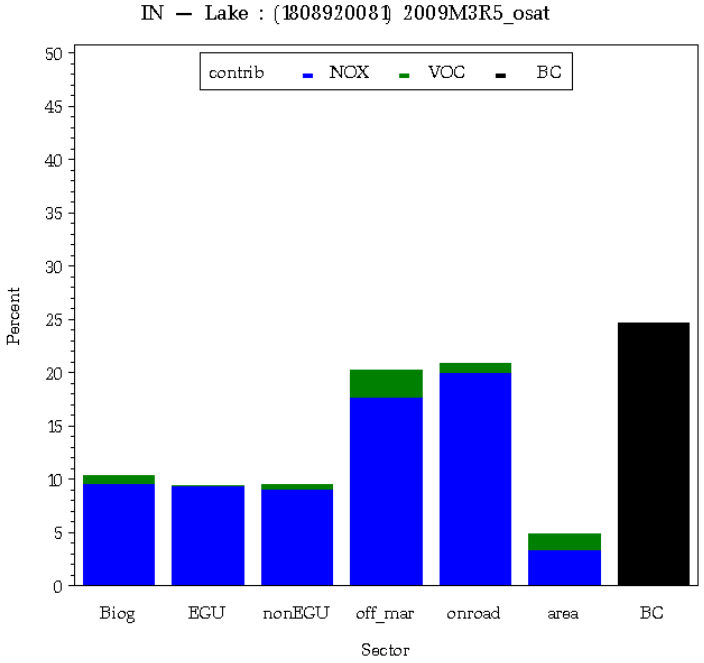

MI — Allegan : (2600500031) K2012R4S1a_APCA_nopig
sector Biog EGU nonEGU off_mar onroad area BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

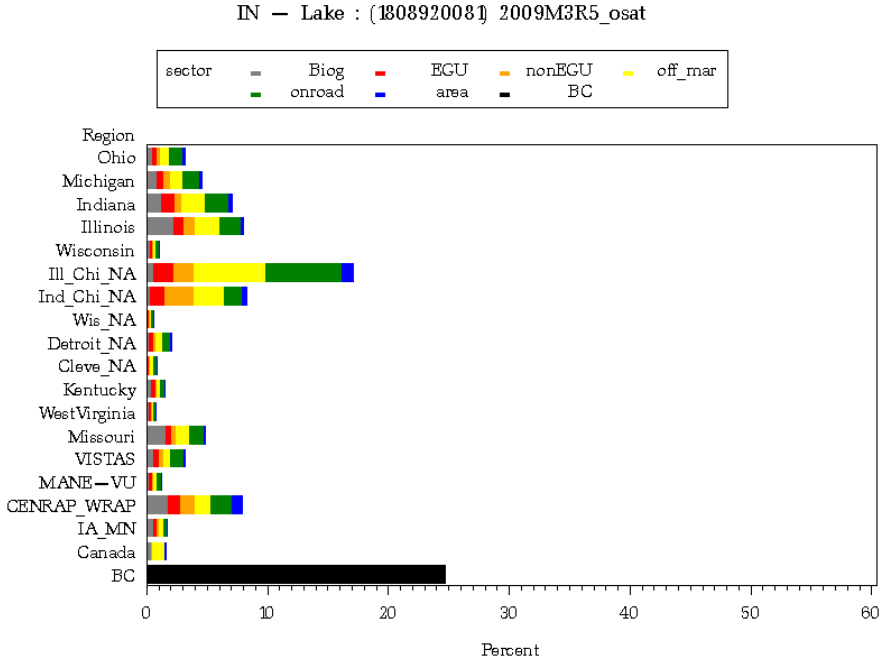

IN — LaPorte : (180910005 1) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector

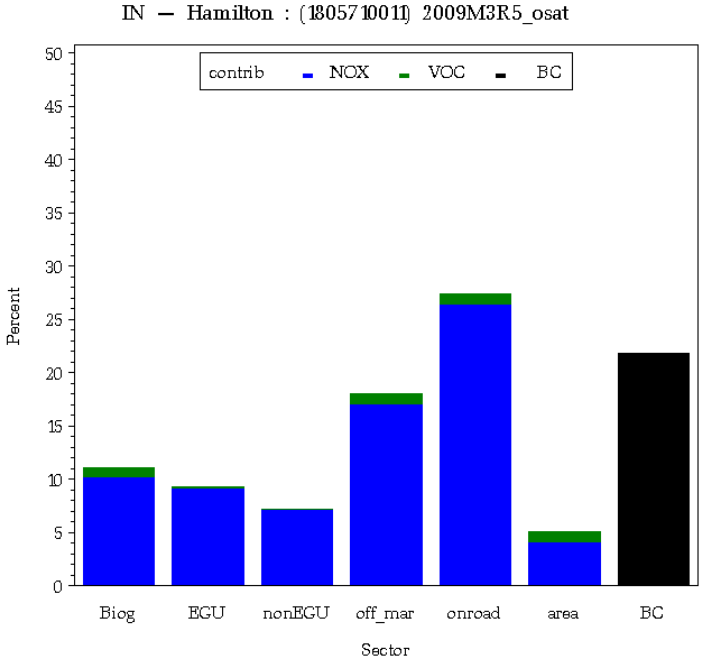

IN — LaPorte : (180910005 1) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

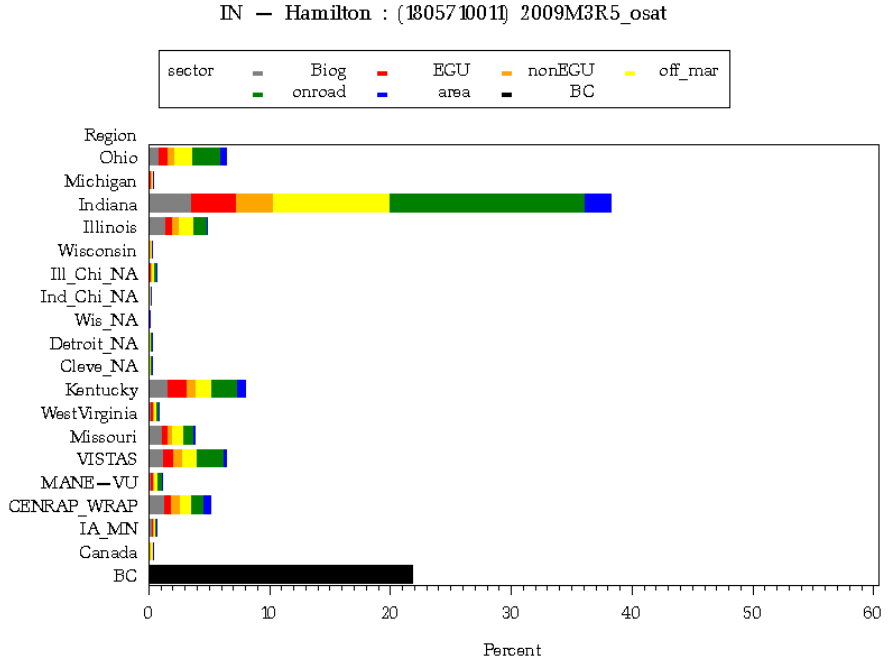

IN — LaPorte : (180910005 1) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector

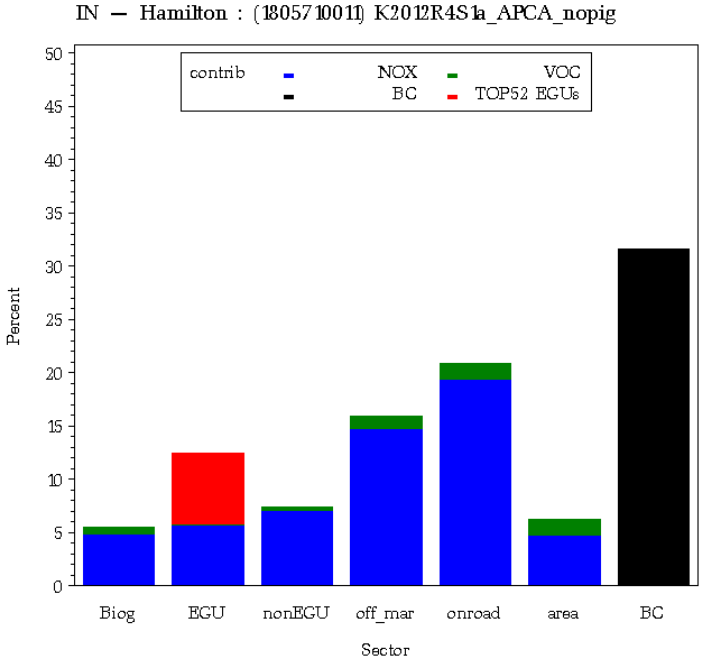

IN — LaPorte : (180910005 1) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

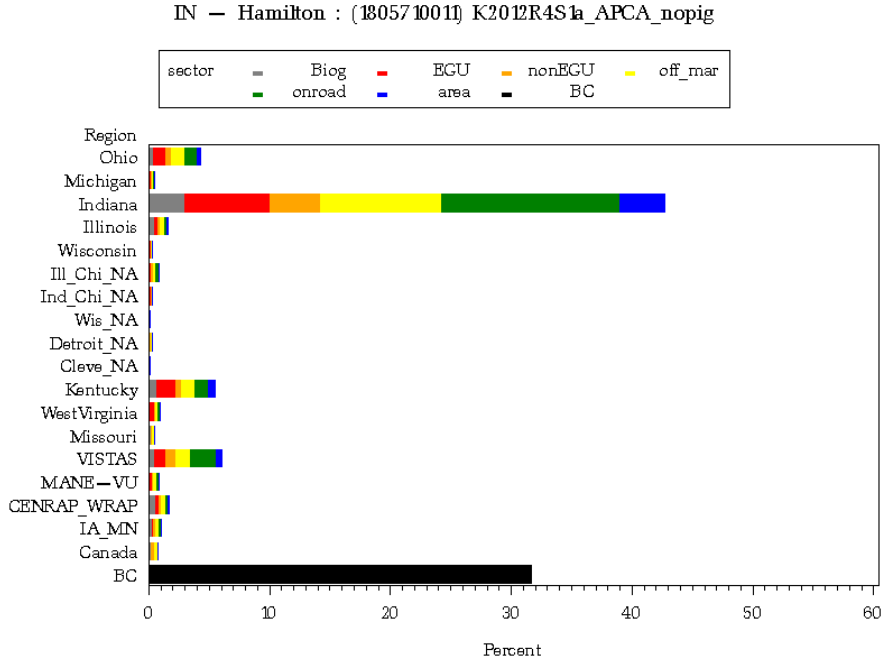

IN — Lake : (1808920081) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
0
5
10
15
20
25
30
35
40
45
50
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — Lake : (1808920081) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
0
10
20
30
40
50
60
Percent


IN — Hamilton : (180571011) 2009M3R5_osat
contrib
NOX
VOC
BC
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector


IN — Hamilton : (180571011) 2009M3R5_osat
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent


IN — Hamilton : (180571011) K2012R4S1a_APCA_nopig
contrib
NOX
VOC
BC
TOP52 EGUs
Percent
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Sector

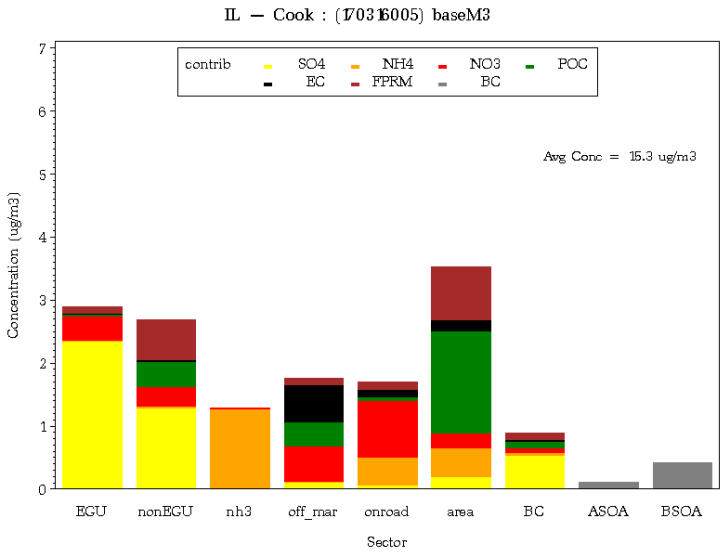

IN — Hamilton : (180571011) K2012R4S1a_APCA_nopig
sector
Biog
EGU
nonEGU
off_mar
onroad
area
BC
Region
Ohio
Michigan
Indiana
Illinois
Wisconsin
Ill_Chi_NA
Ind_Chi_NA
Wis_NA
Detroit_NA
Cleve_NA
Kentucky
WestVirginia
Missouri
VISTAS
MANE—VU
CENRAP_WRAP
IA_MN
Canada
BC
Percent

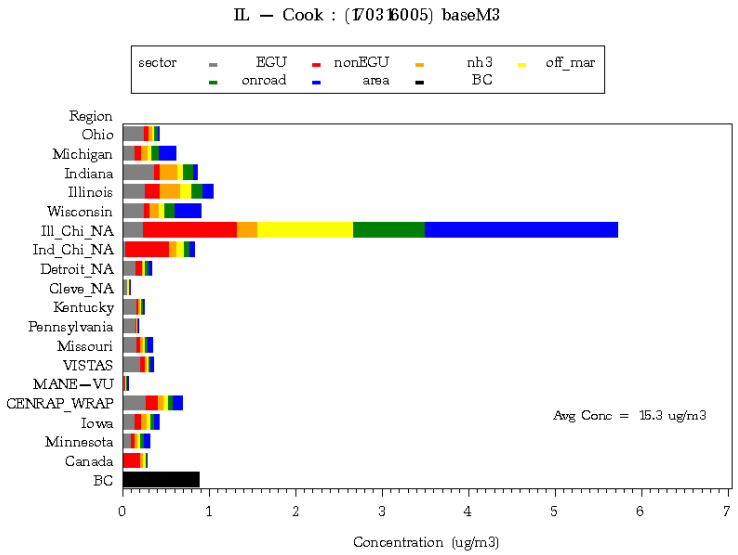
APPENDIX III

$PM_{2.5}$ Source Apportionment Modeling Results

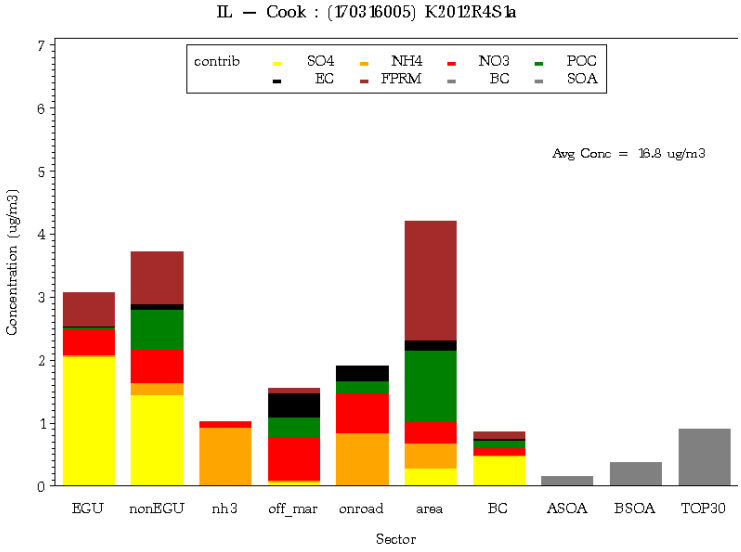
Chicago (Cicero), Illinois

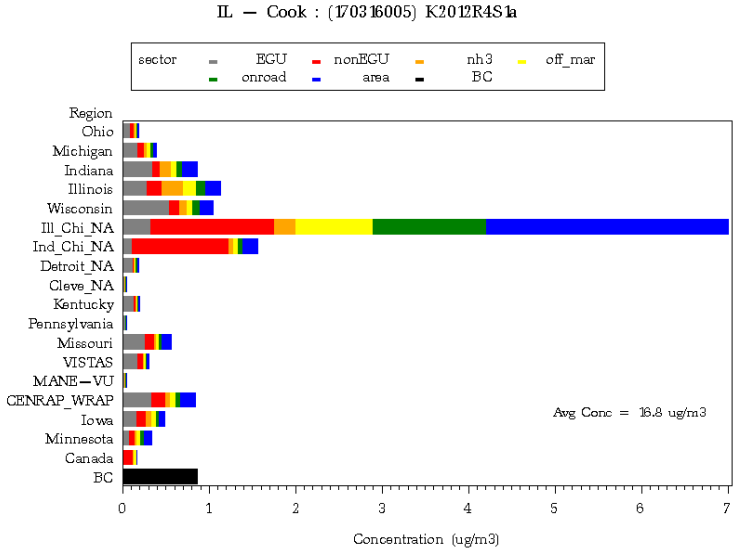
2005 (Round 5)



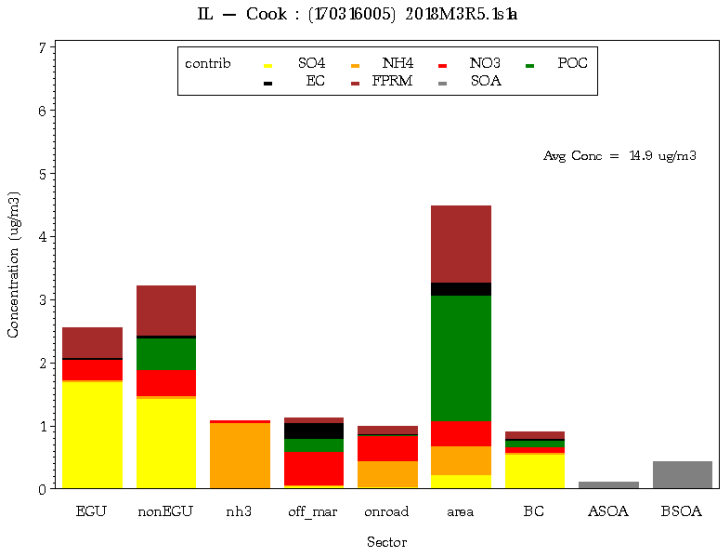


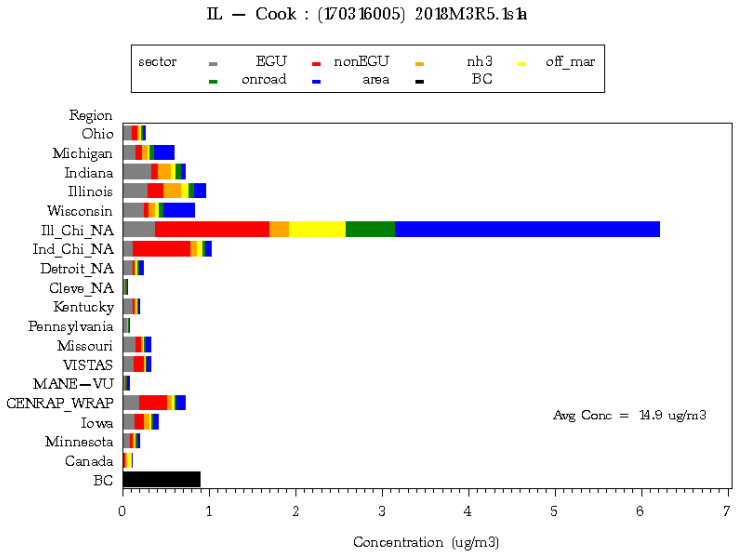
2012 (Round 4)





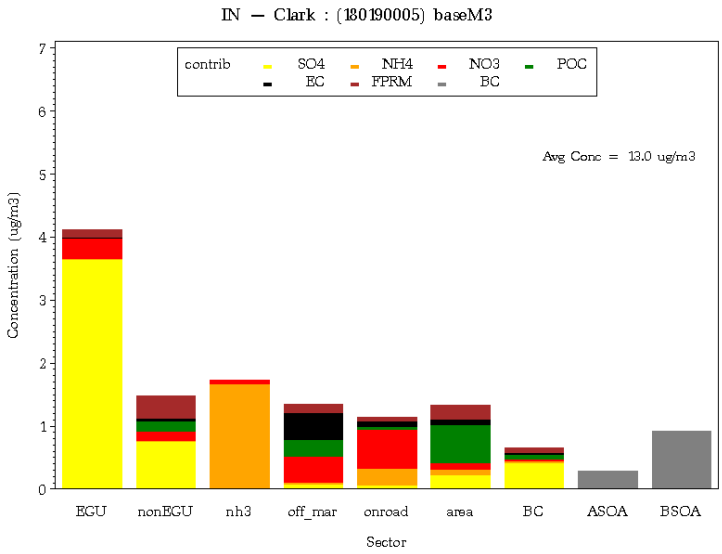
2018 (Round 5)

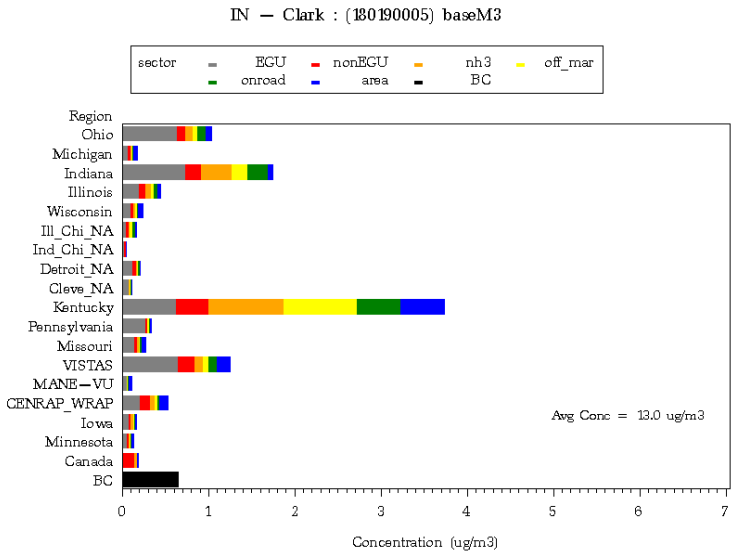




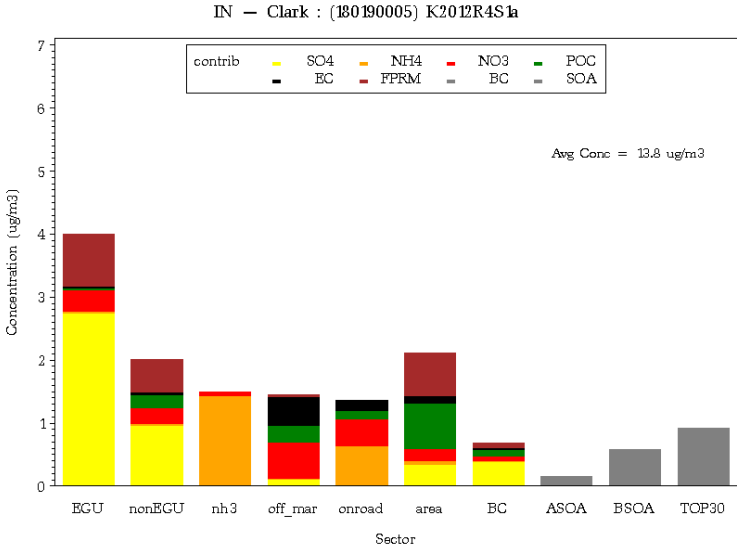
Clark County, Indiana

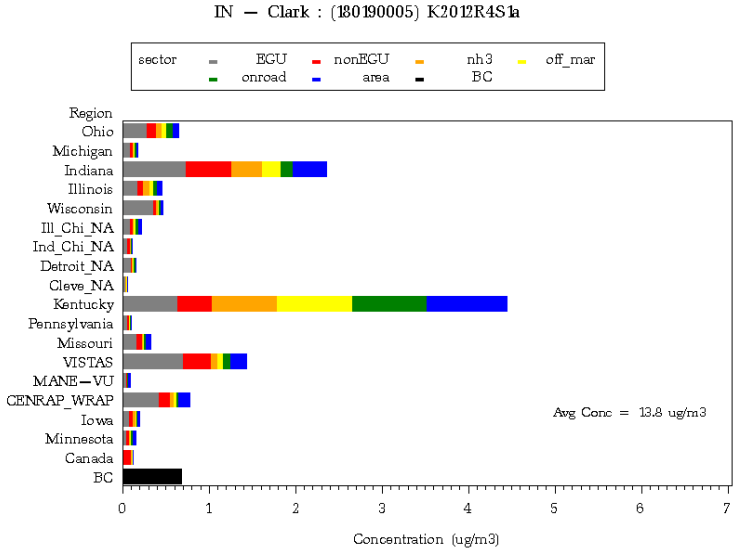
2005 (Round 5)



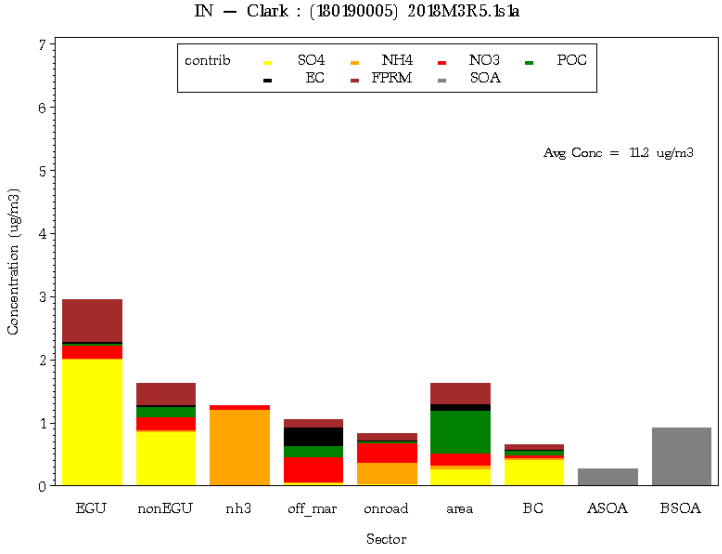


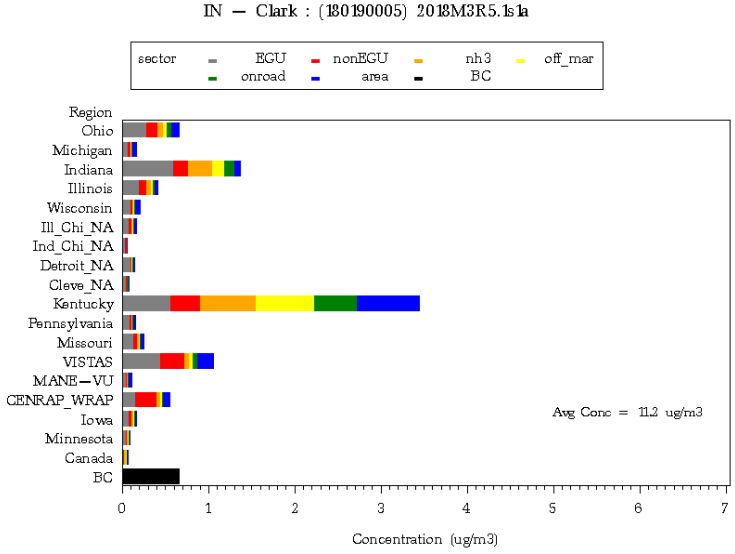
2012 (Round 4)





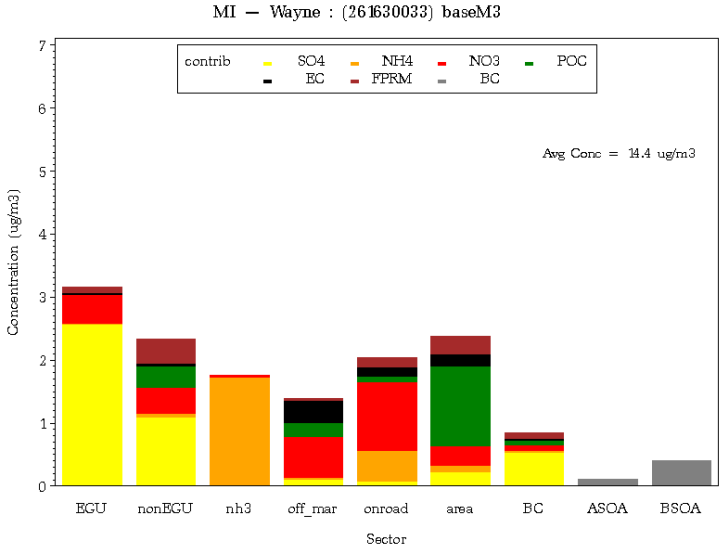
2018 (Round 5)

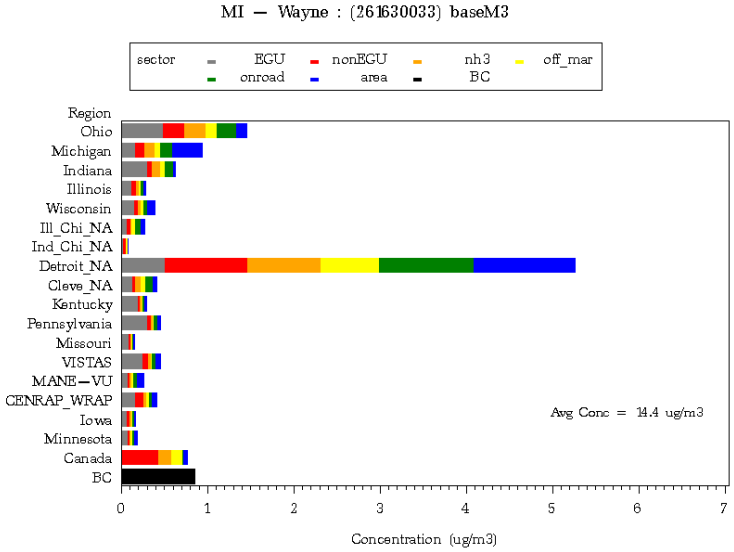




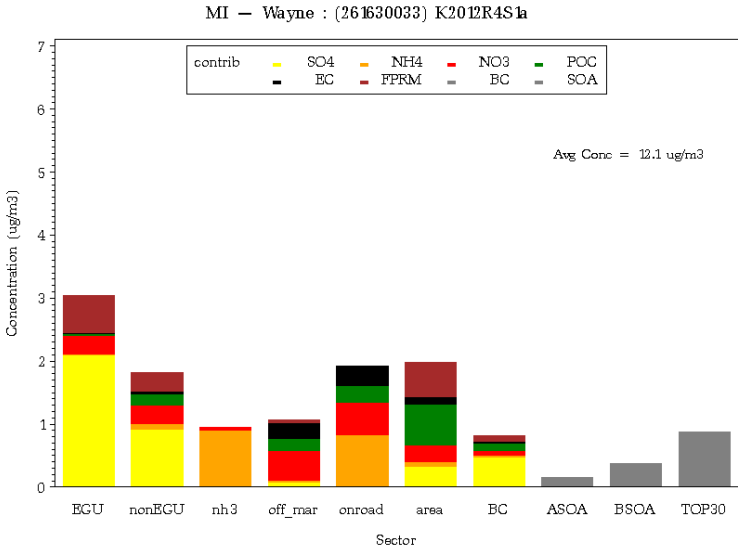
Dearborn, Michigan

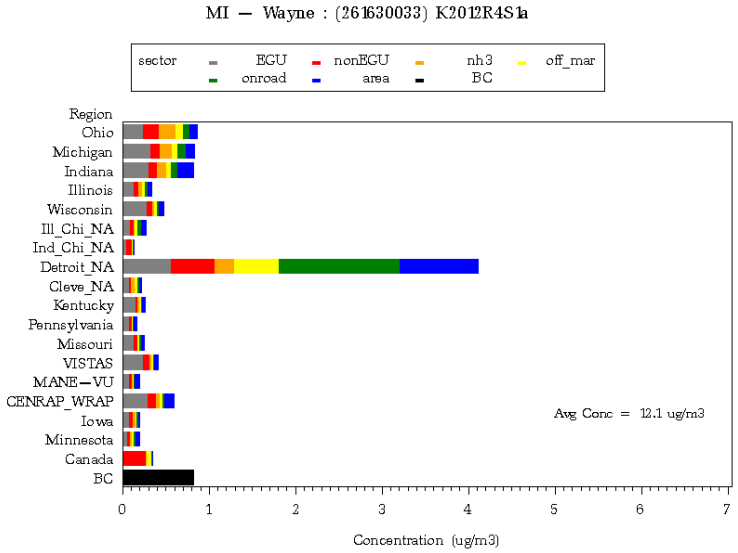
2005 (Round 5)



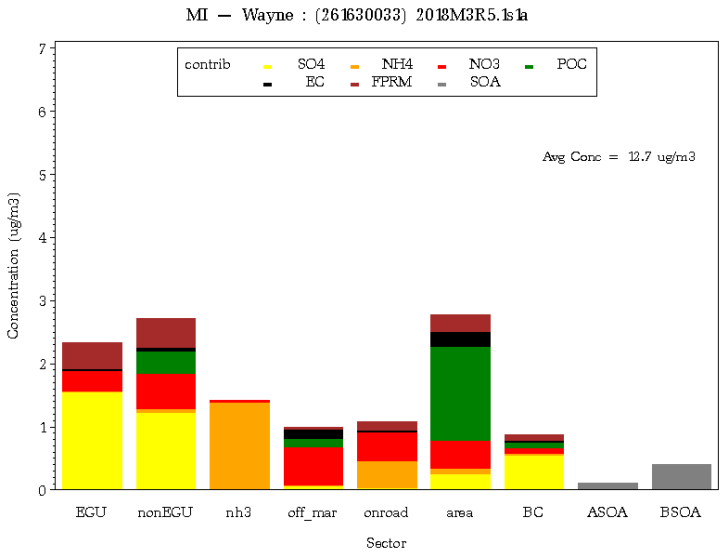


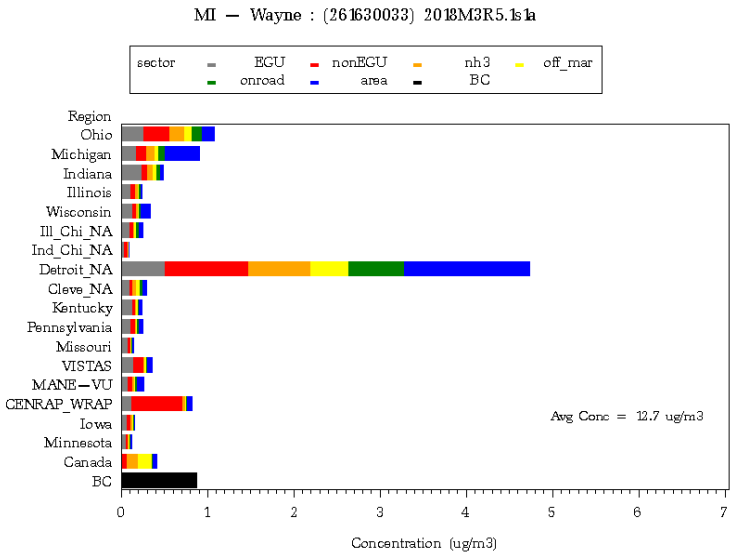
2012 (Round 4)





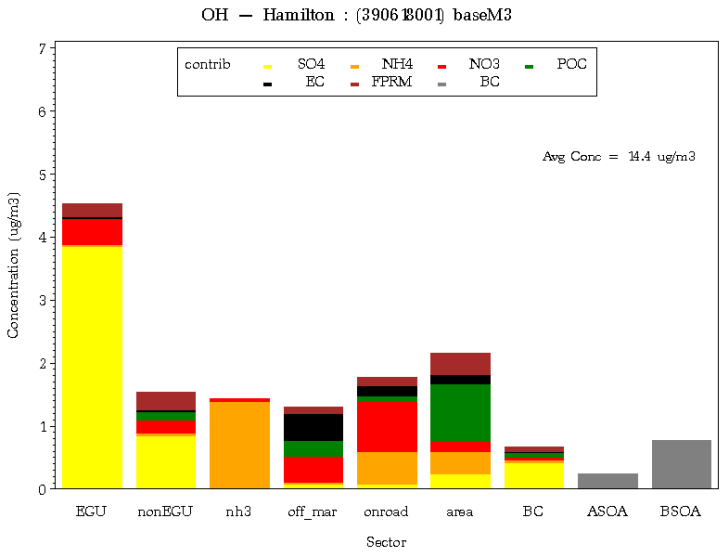
2018 (Round 5)

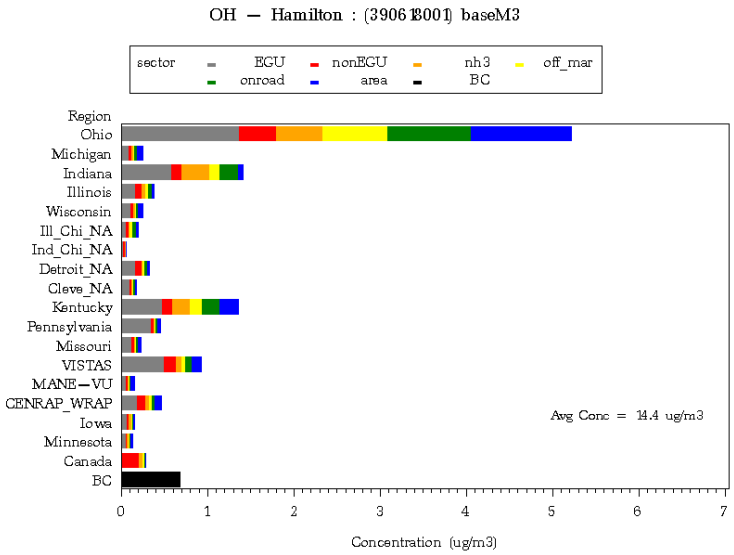




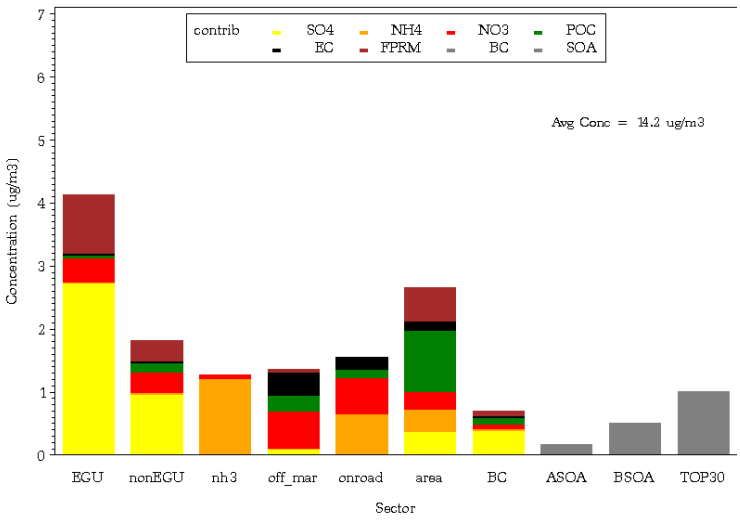
Cincinnati, Ohio

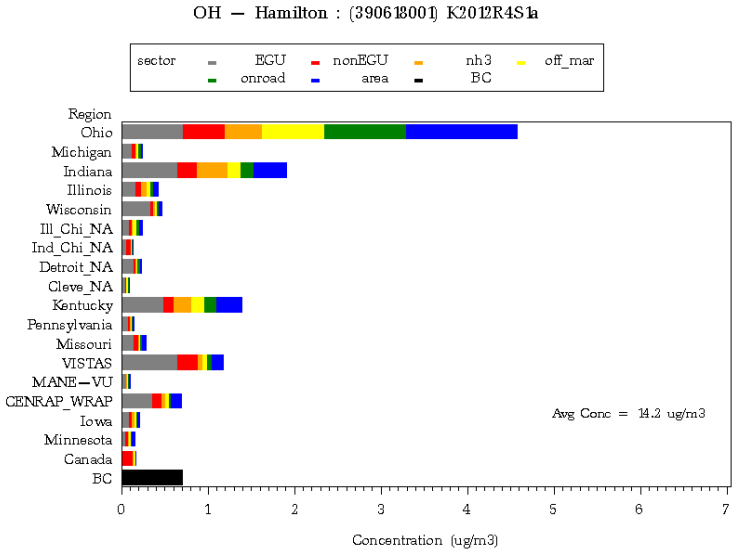
2005 (Round 5)



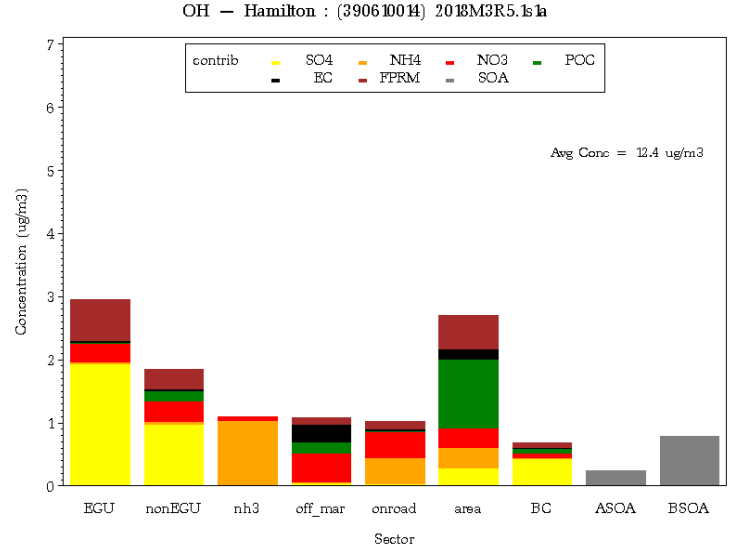


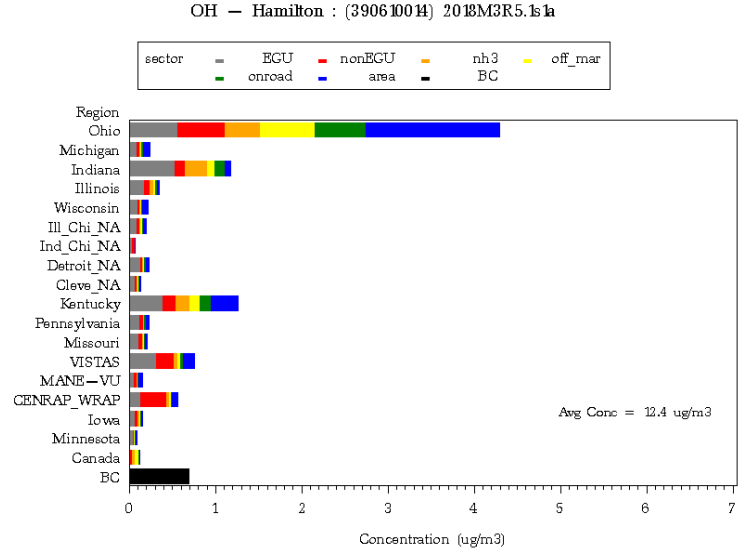
2012 (Round 4)





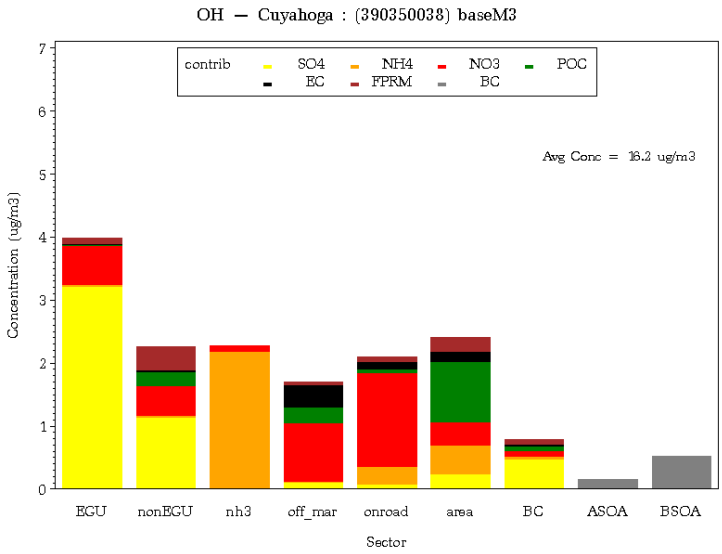
2018 (Round 5)

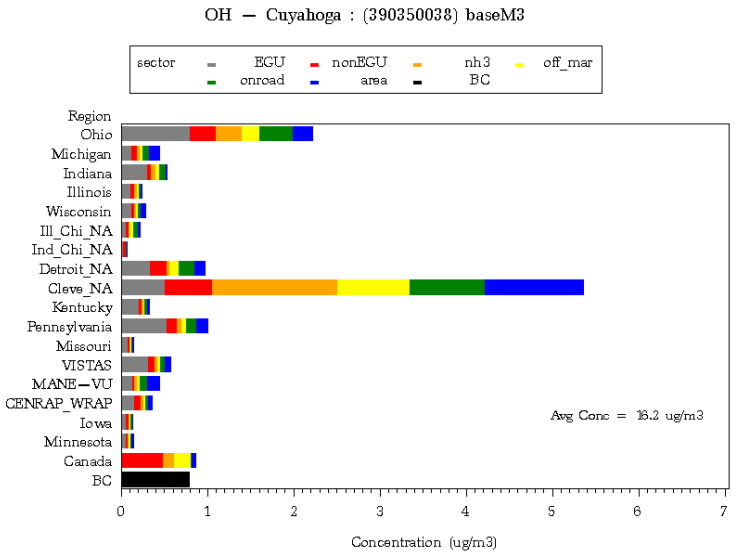




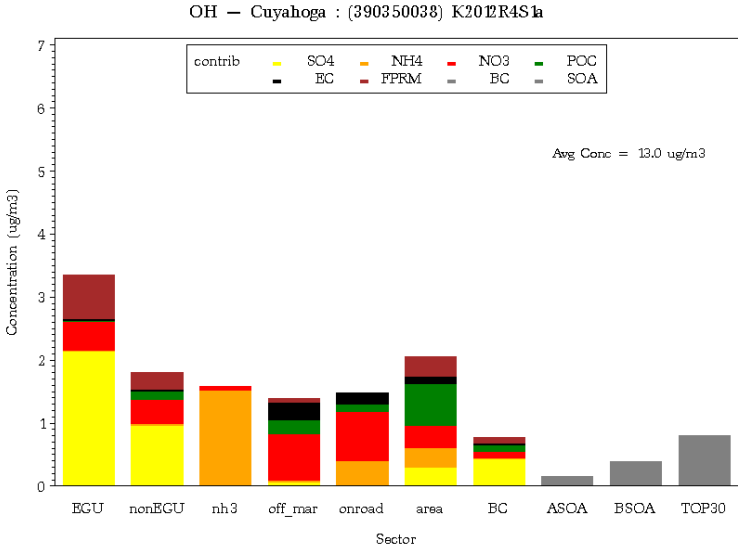
Cleveland, Ohio

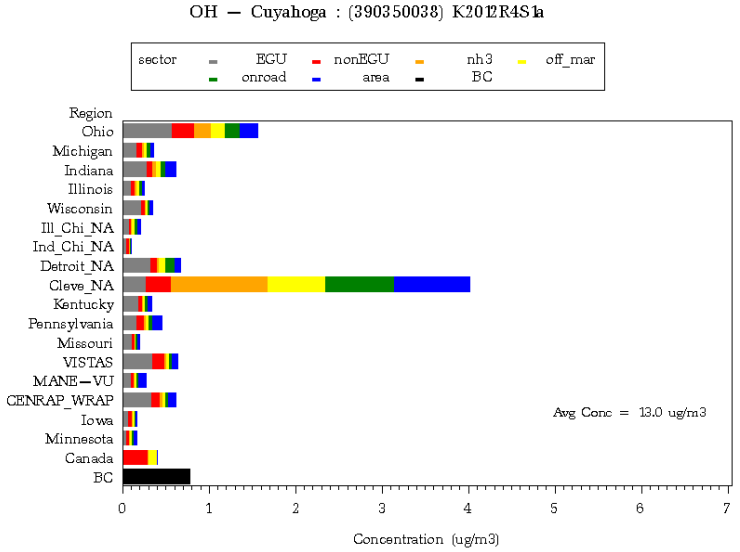
2005 (Round 5)



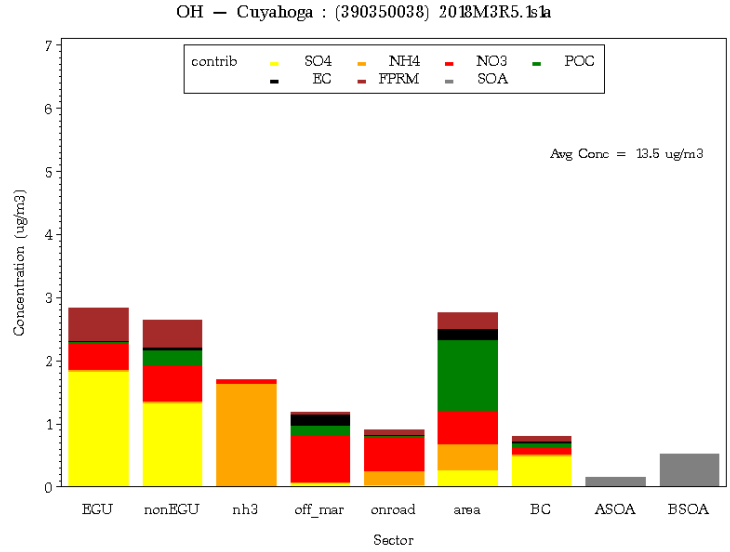


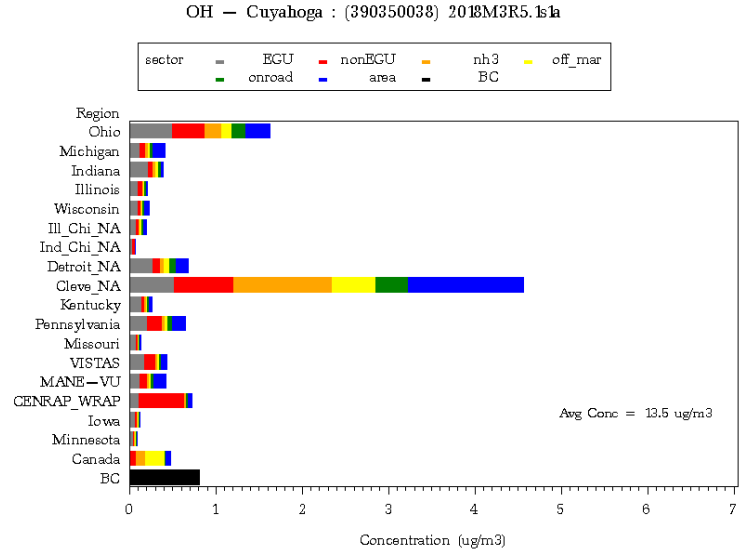
2012 (Round 4)





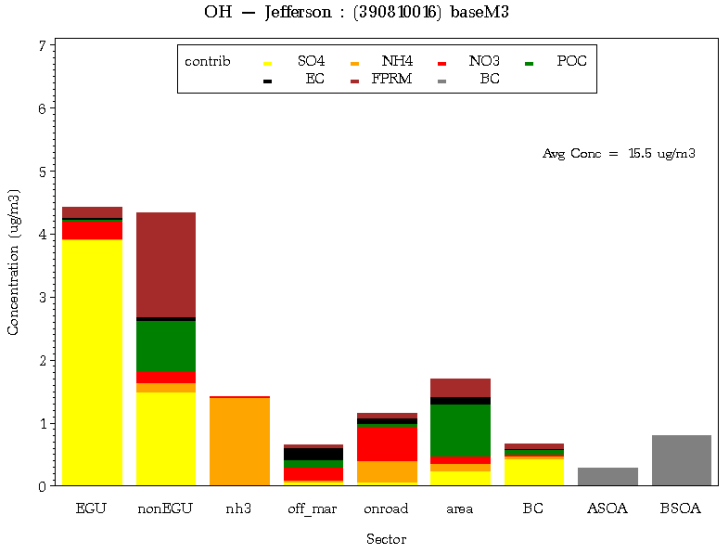
2018 (Round 5)

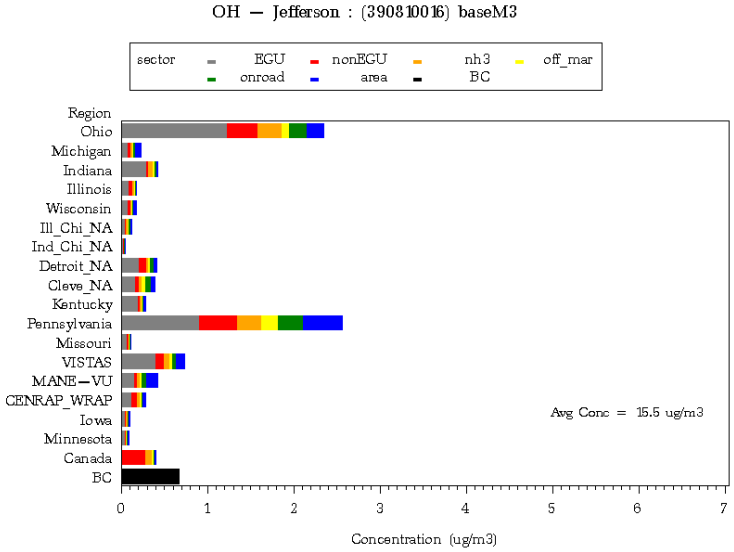




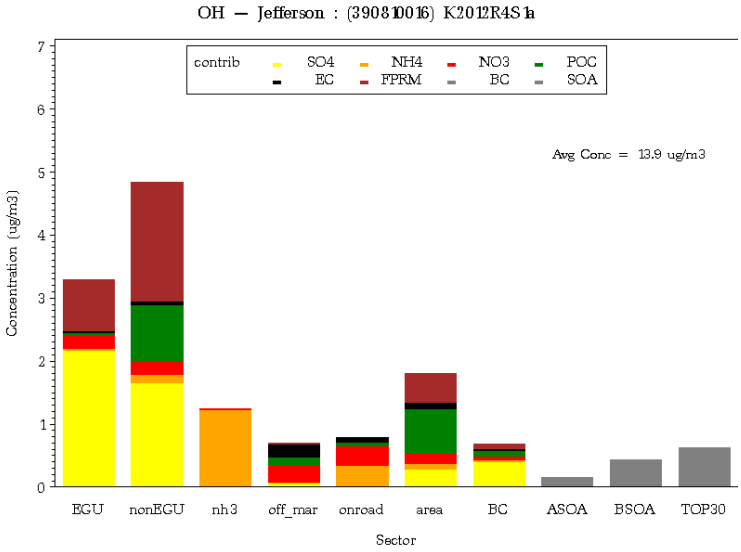
Steubenville, Ohio

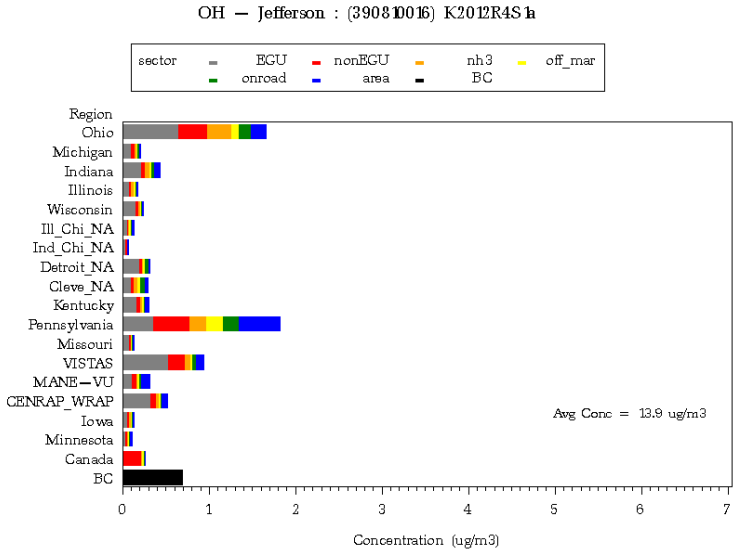
2005 (Round 5)



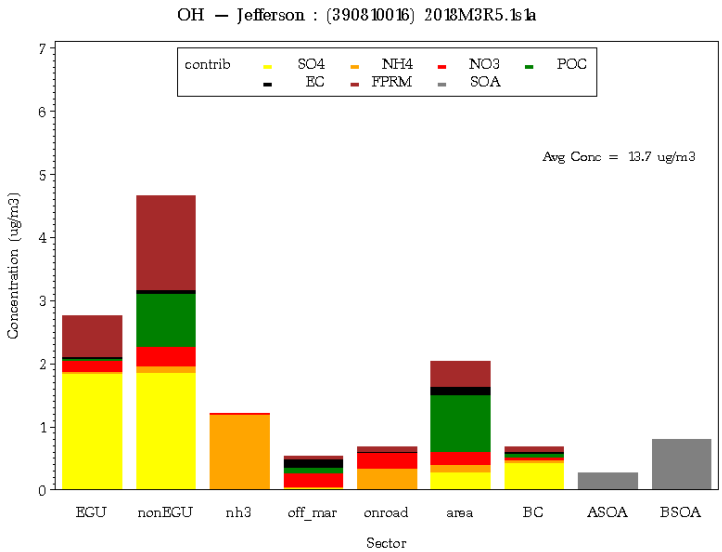


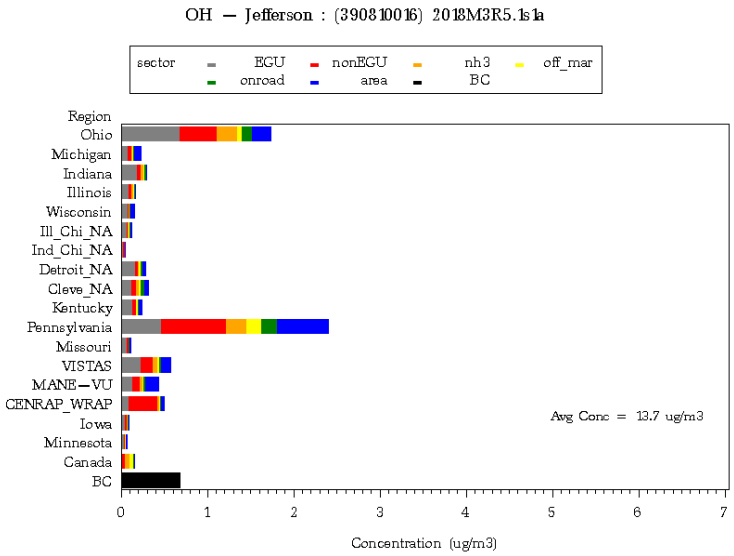
2012 (Round 4)





2018 (Round 5)



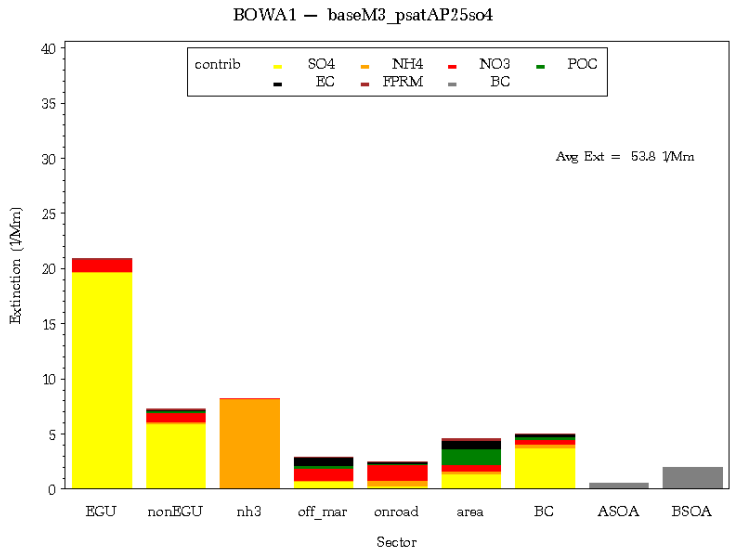


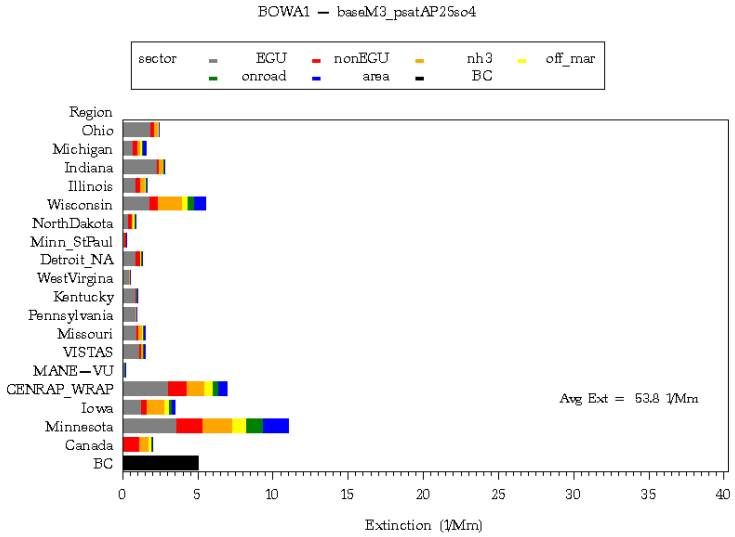
APPENDIX IV

Haze Source Apportionment Modeling Results

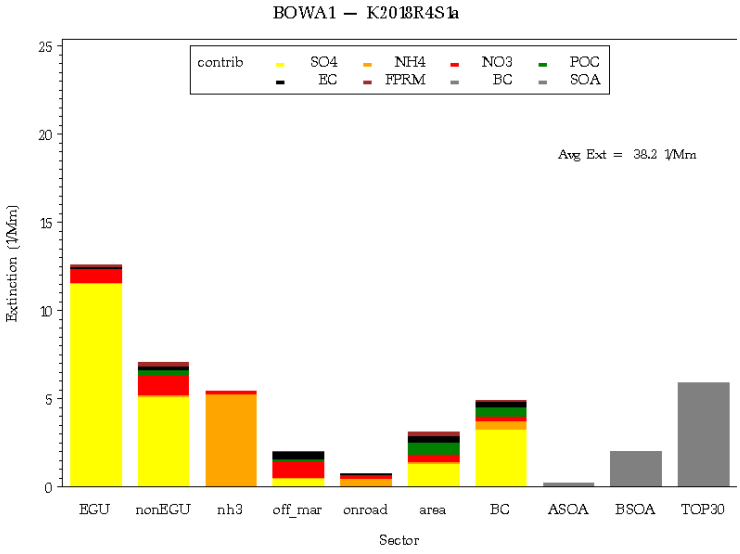
Boundary Waters, Minnesota

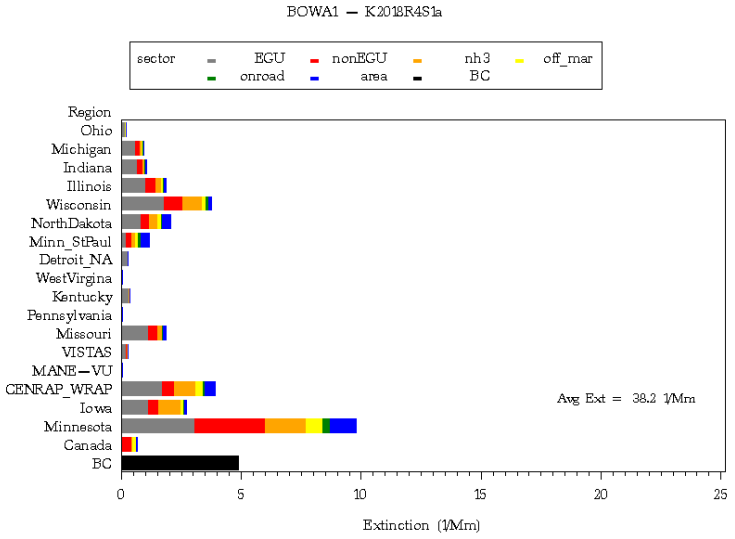
2005 (Round 5)



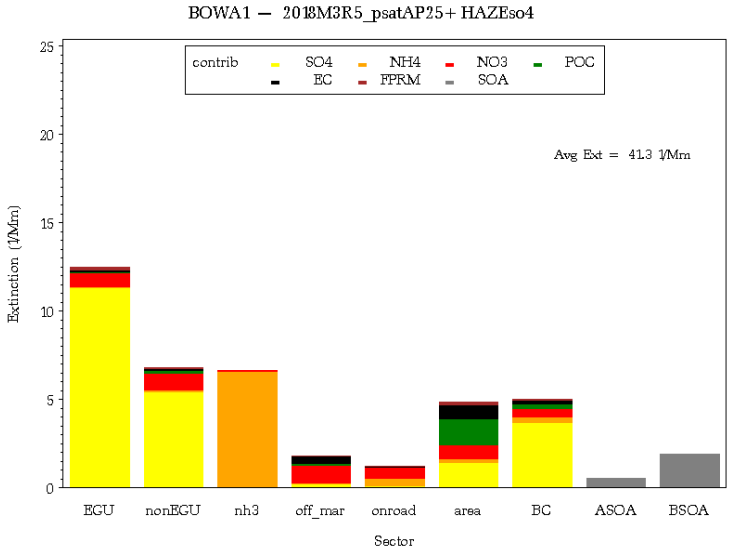


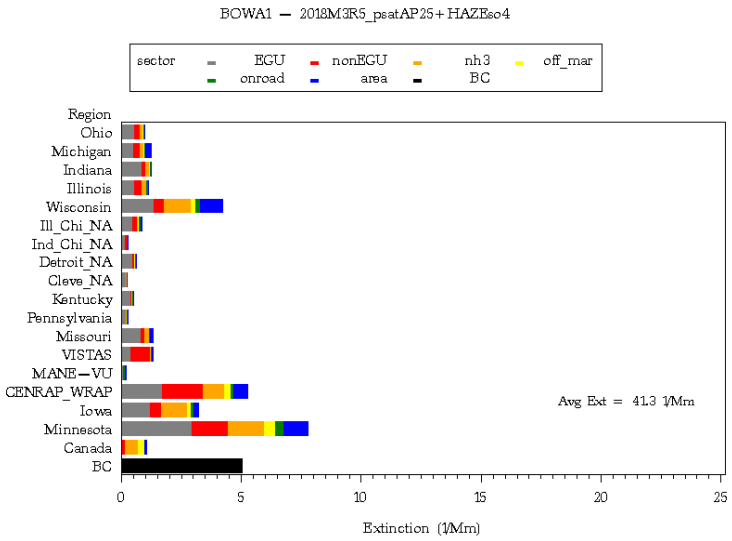
2018 (Round 4)





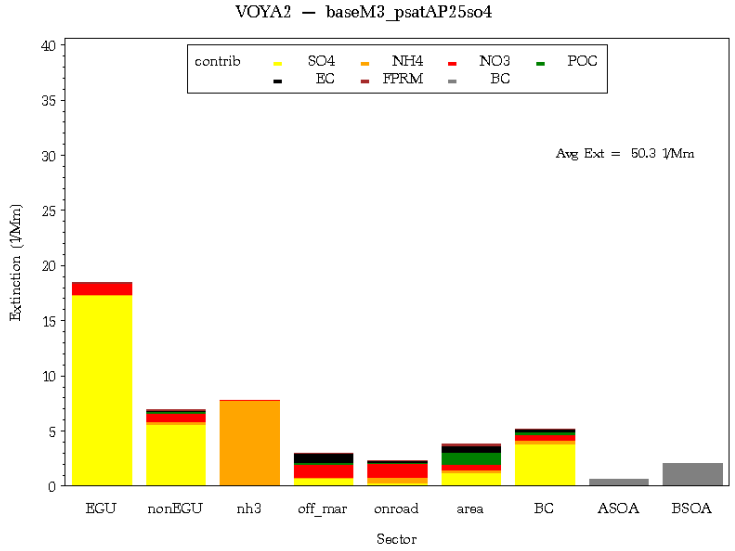
2018 (Round 5)

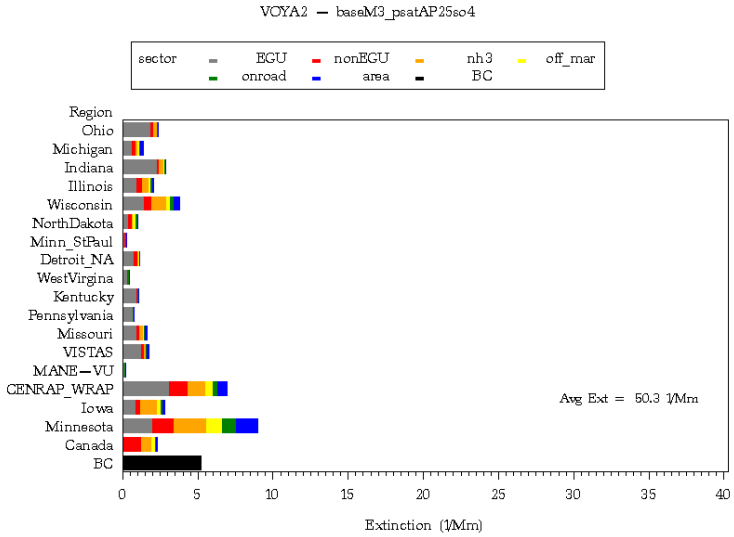




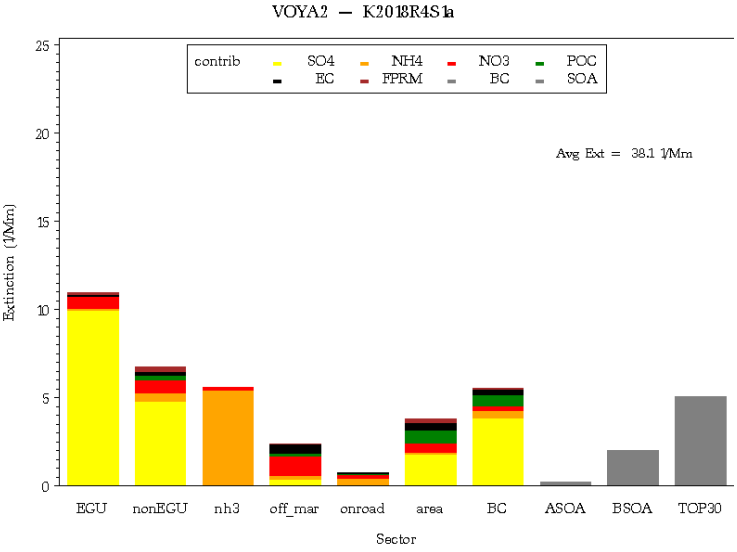
Voyageurs, Minnesota

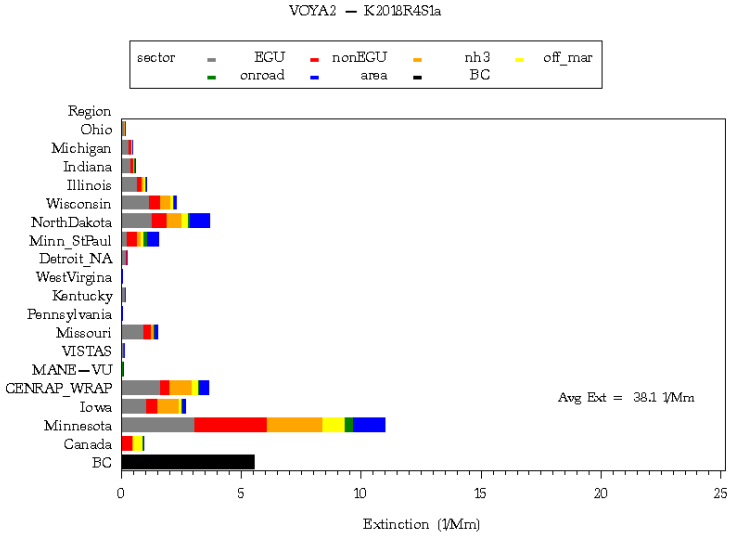
2005 (Round 5)



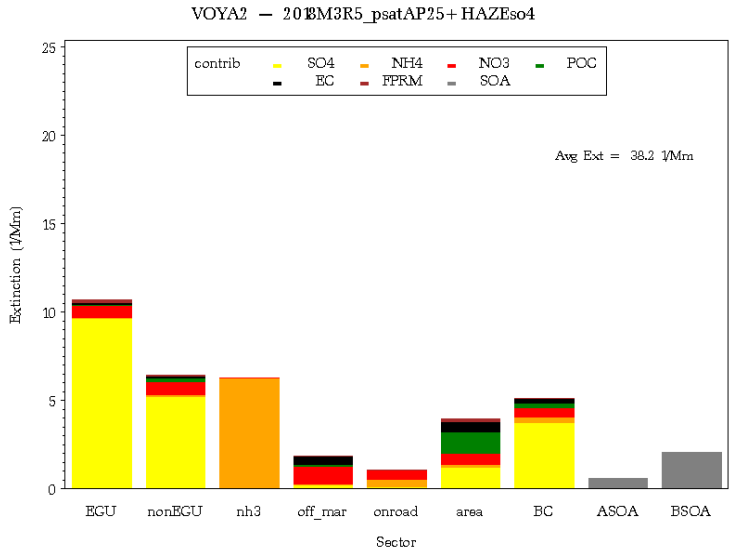


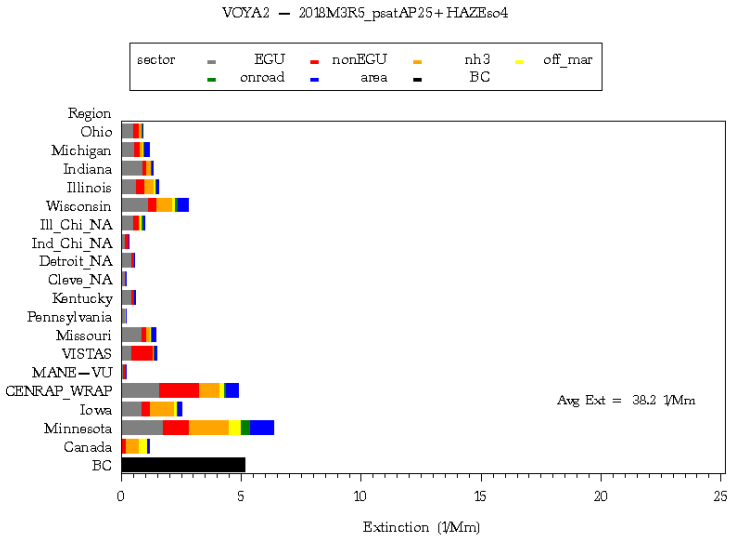
2018 (Round 4)





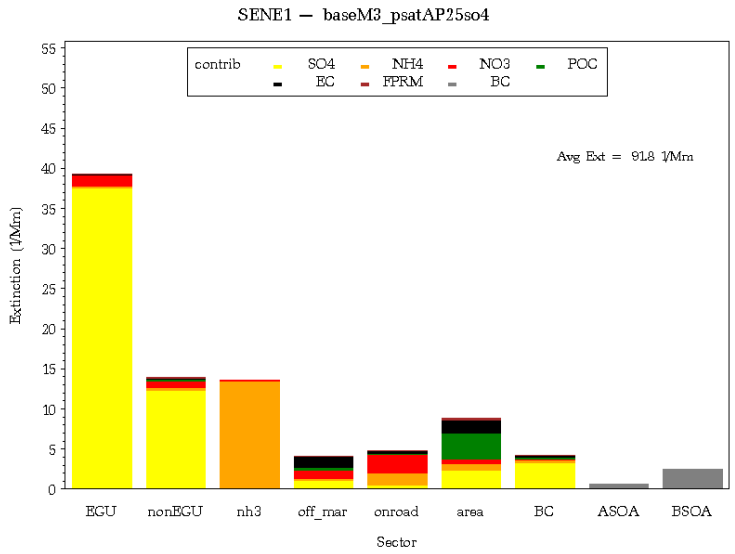
2018 (Round 5)

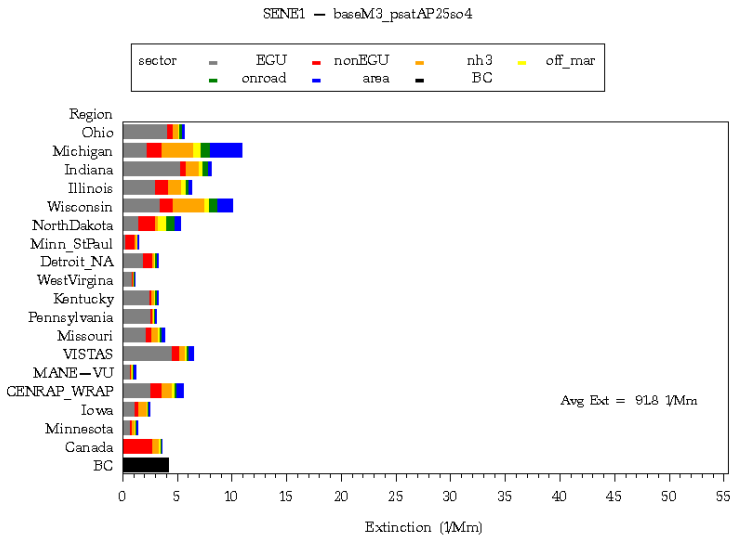




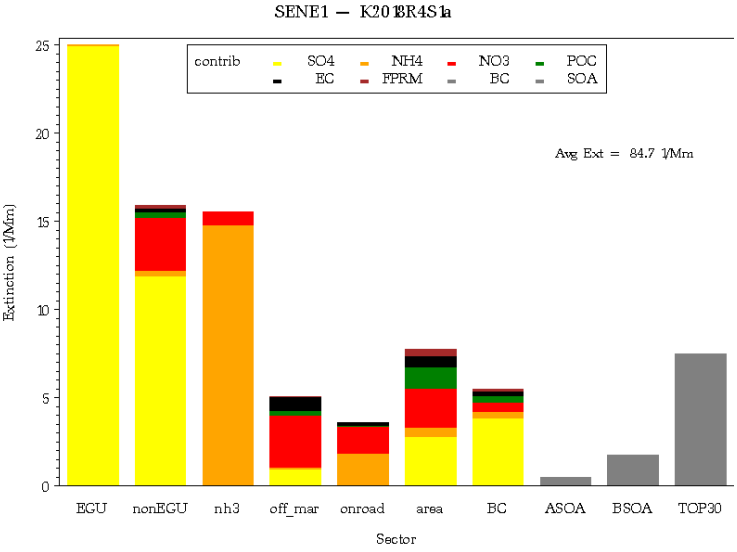
Seney, Michigan

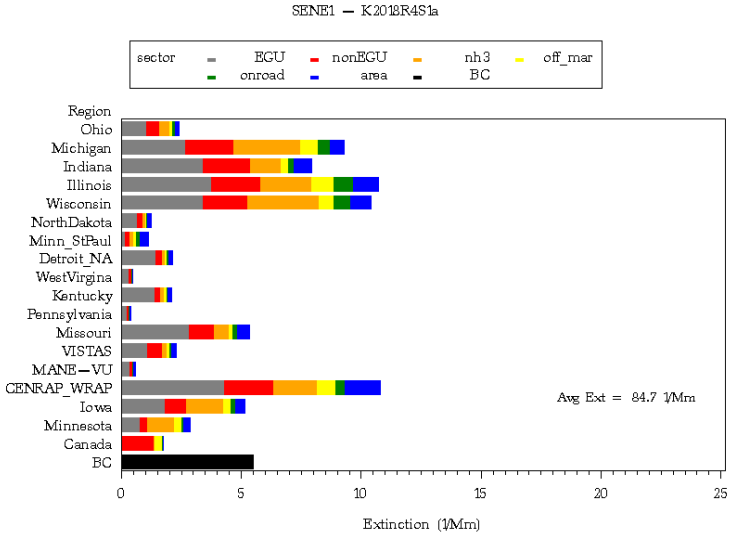
2005 (Round 5)





2018 (Round 4)





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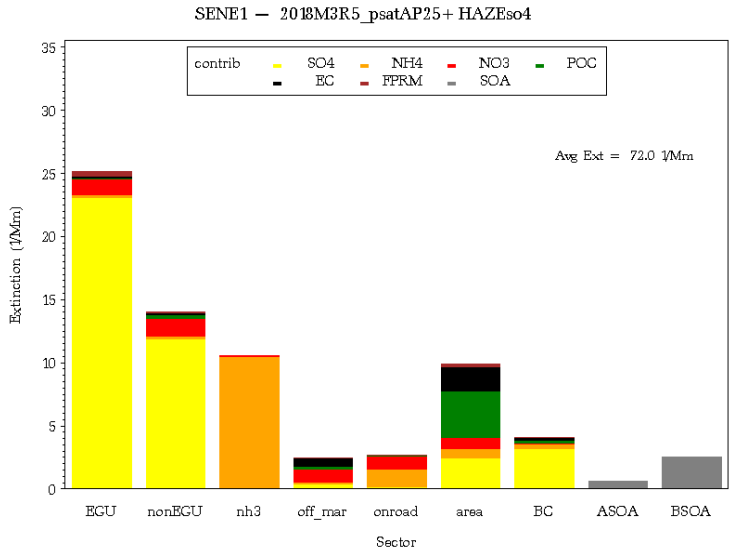
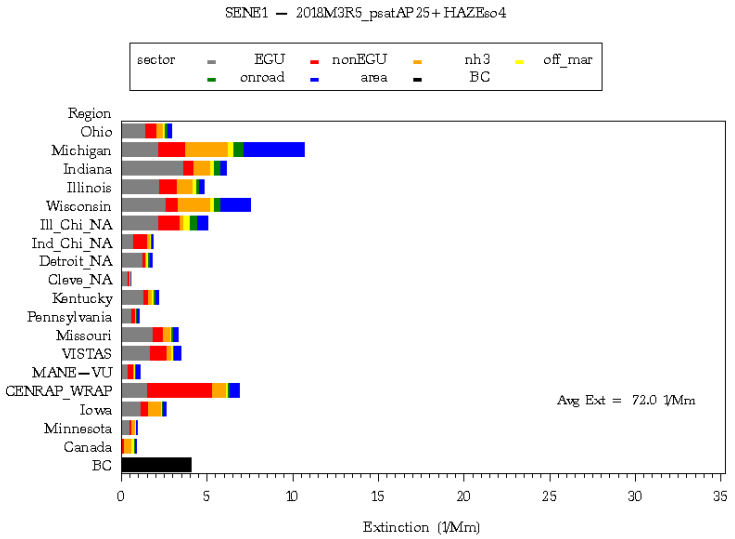
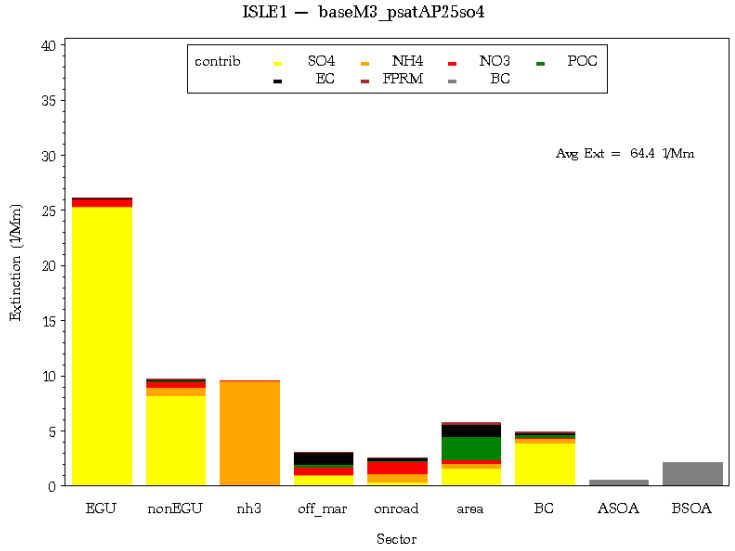
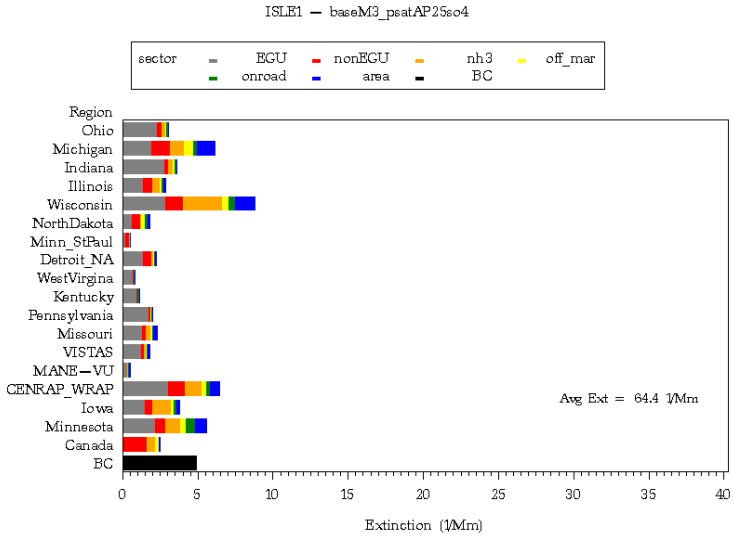




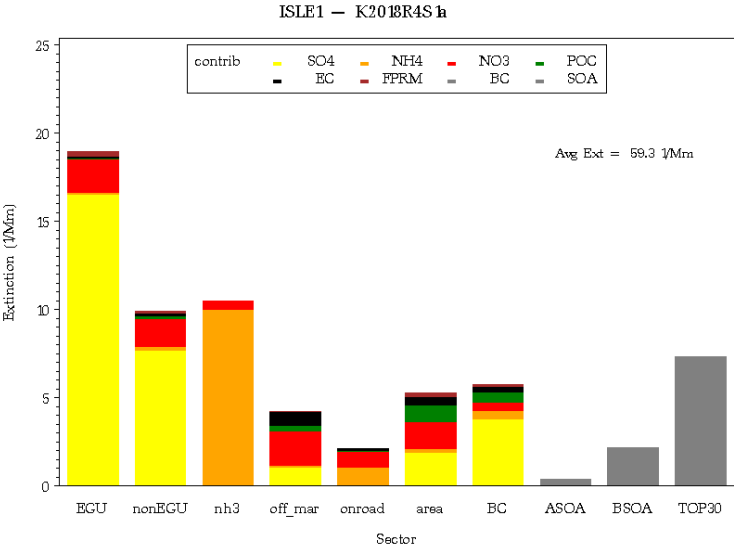
Isle Royale, Michigan

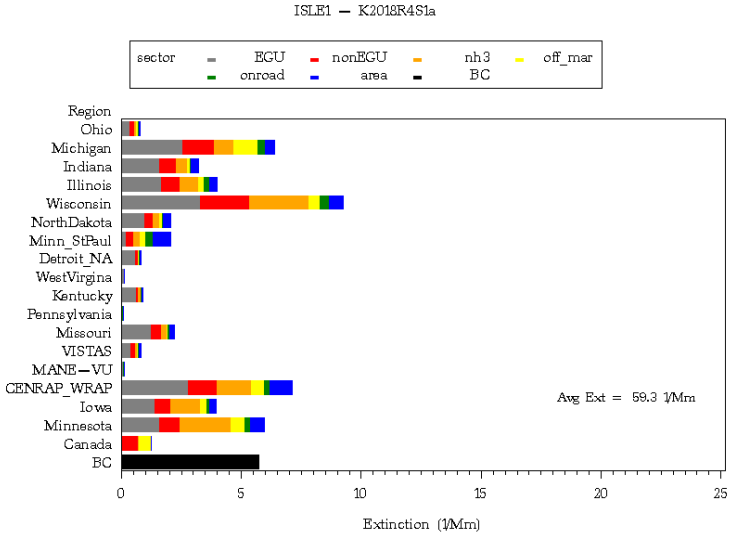
2005 (Round 5)



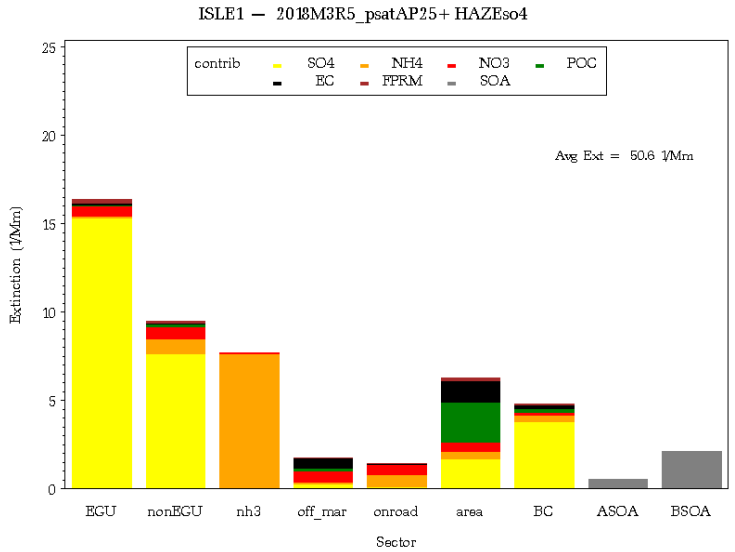


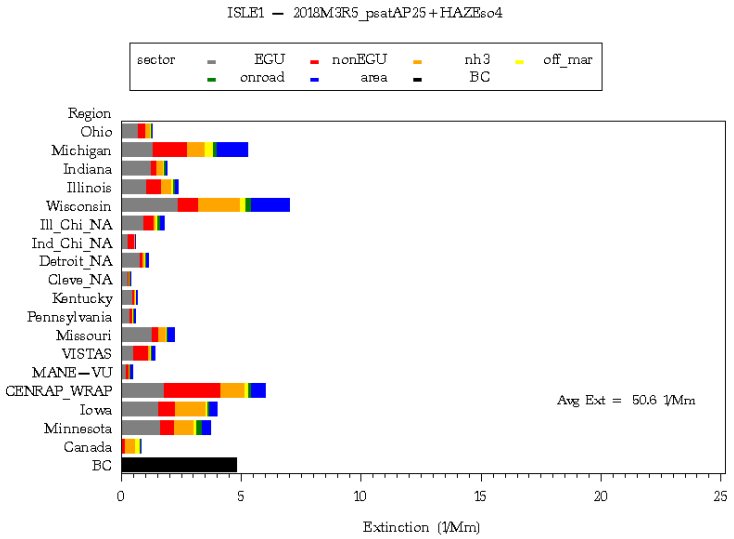
2018 (Round 4)





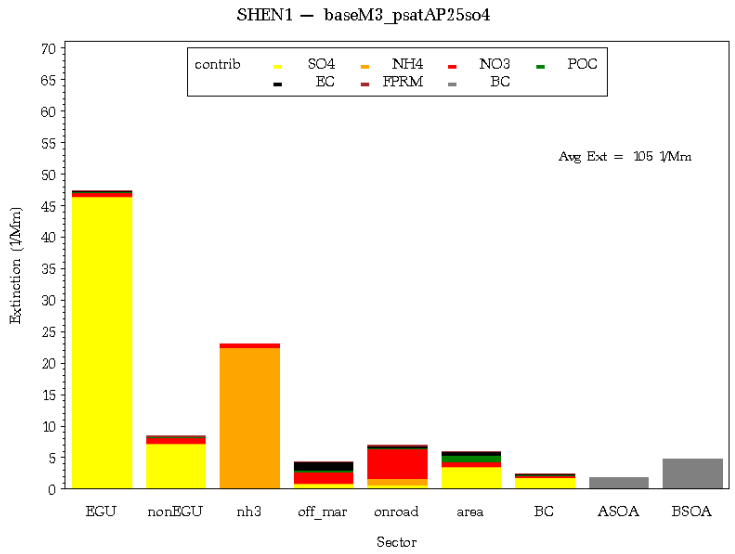
2018 (Round 5)

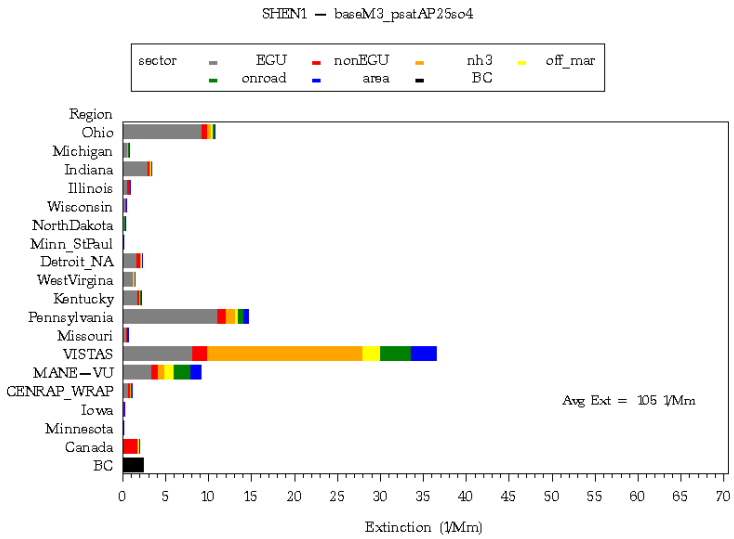




Shenandoah, Virginia

2005 (Round 5)





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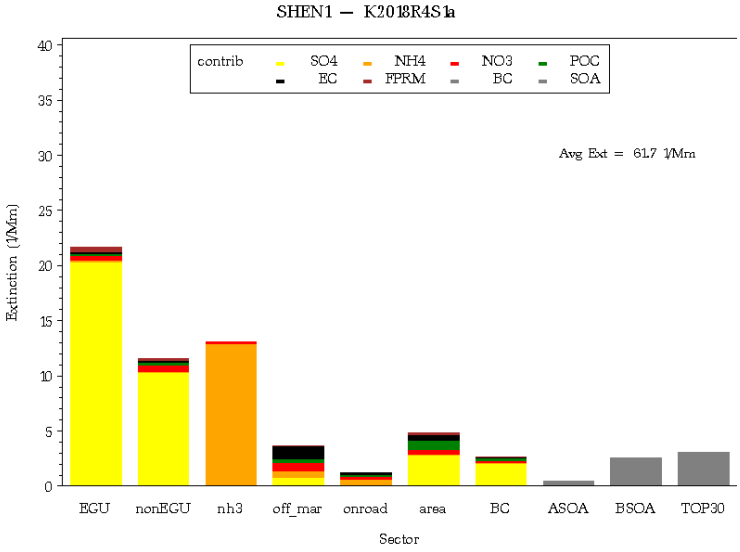
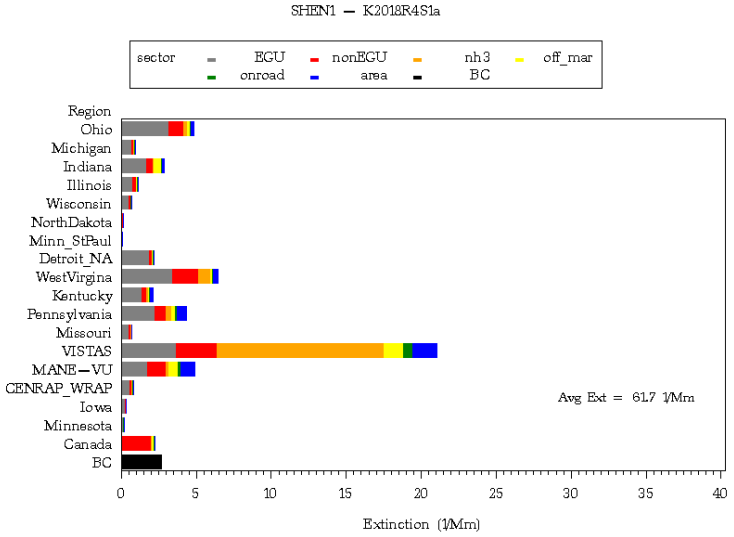
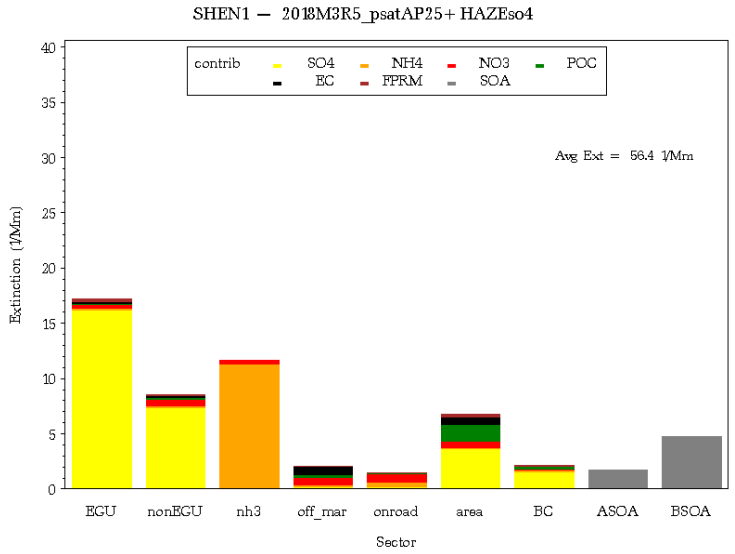
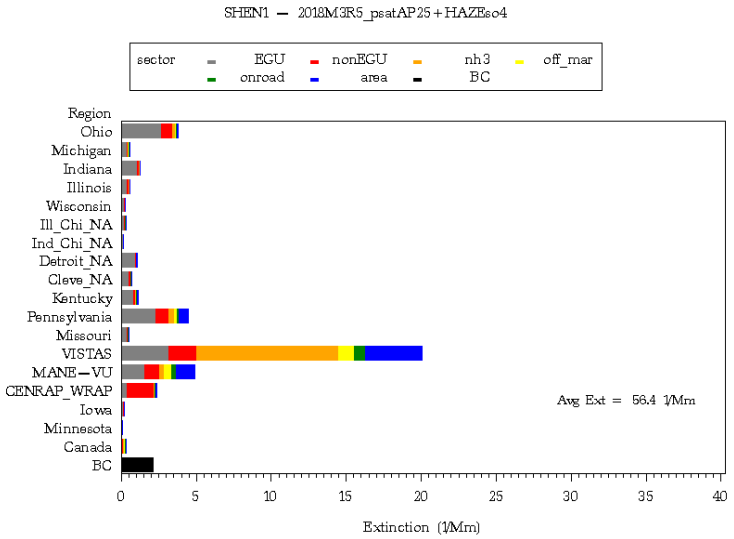




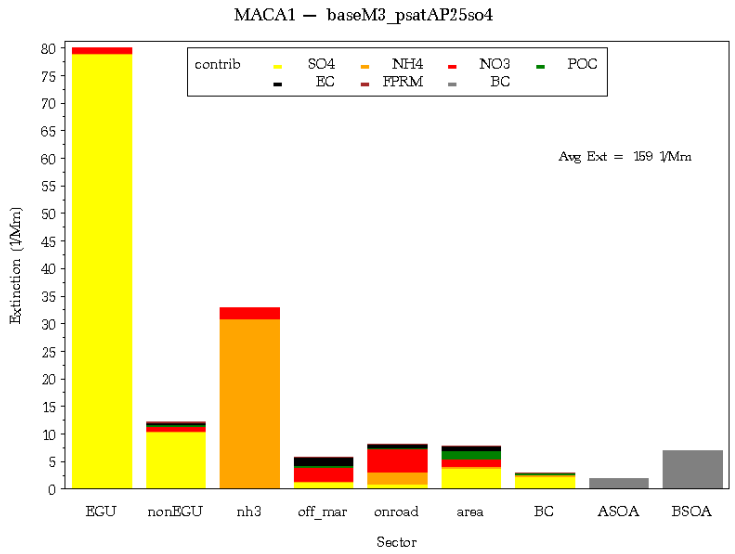
2018 (Round 5)

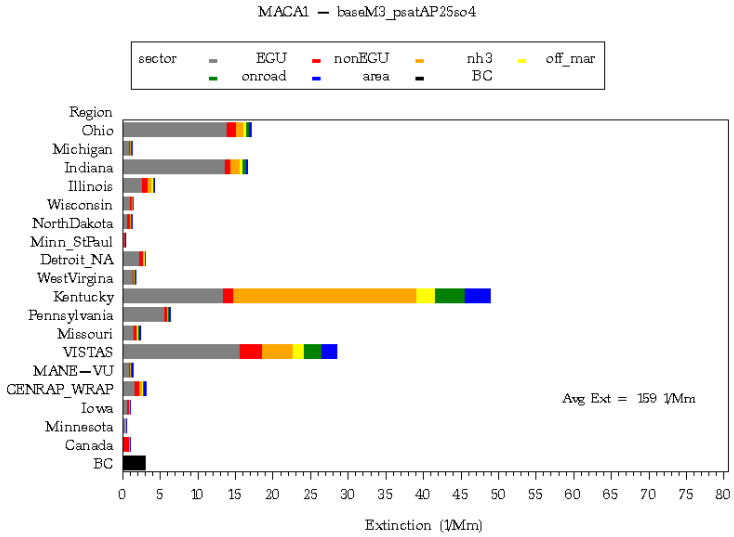




Mammoth Cave, Kentucky

2005 (Round 5)





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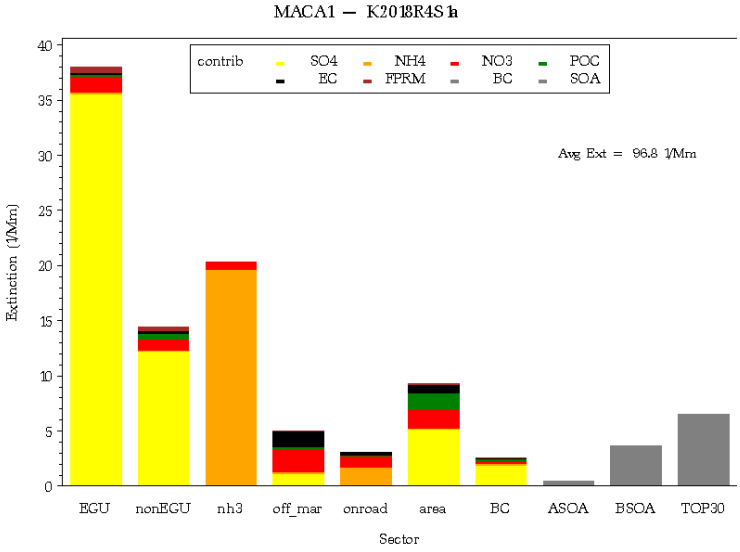

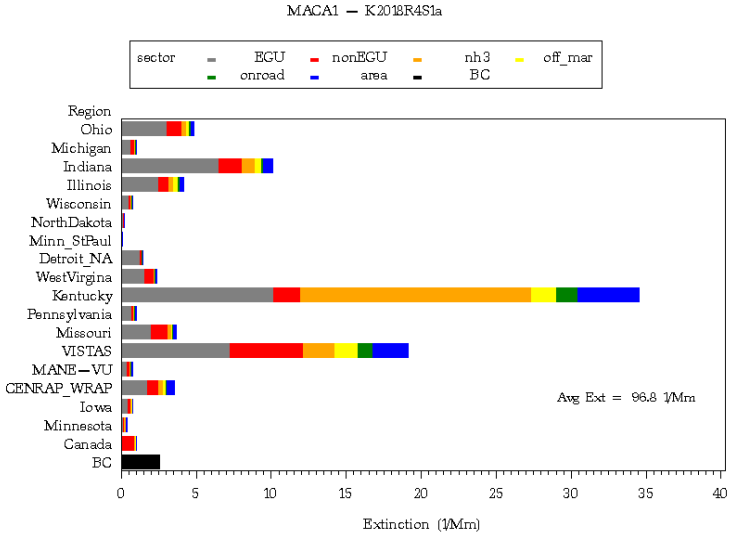

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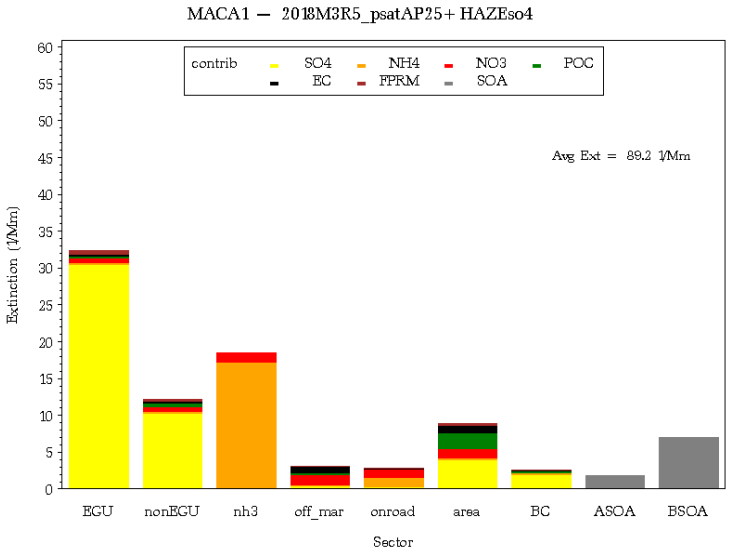
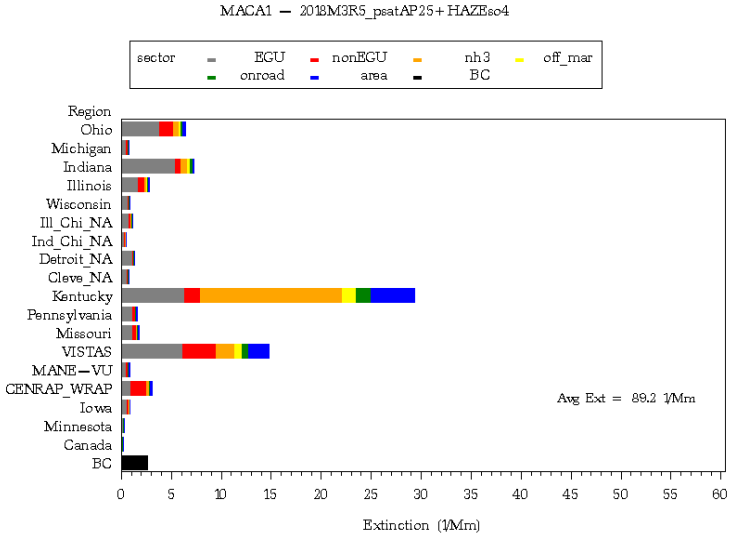
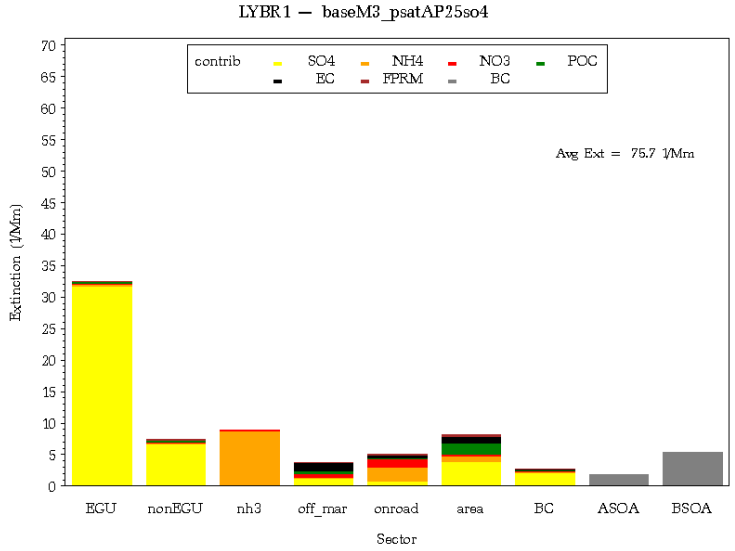
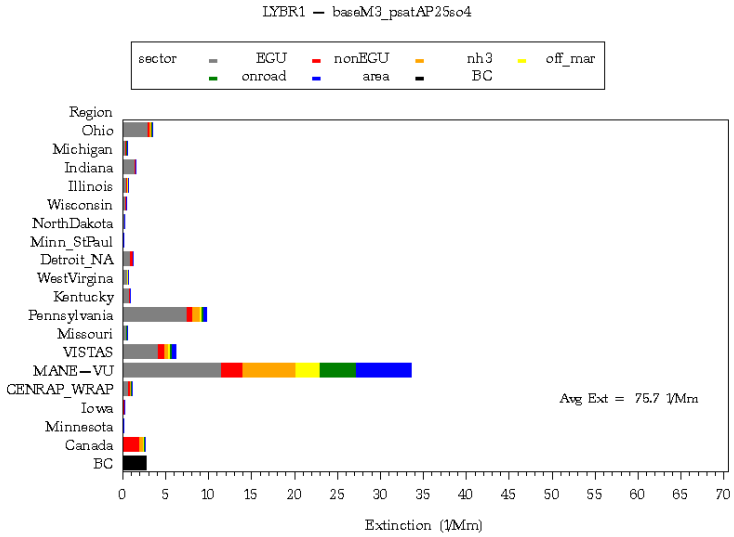




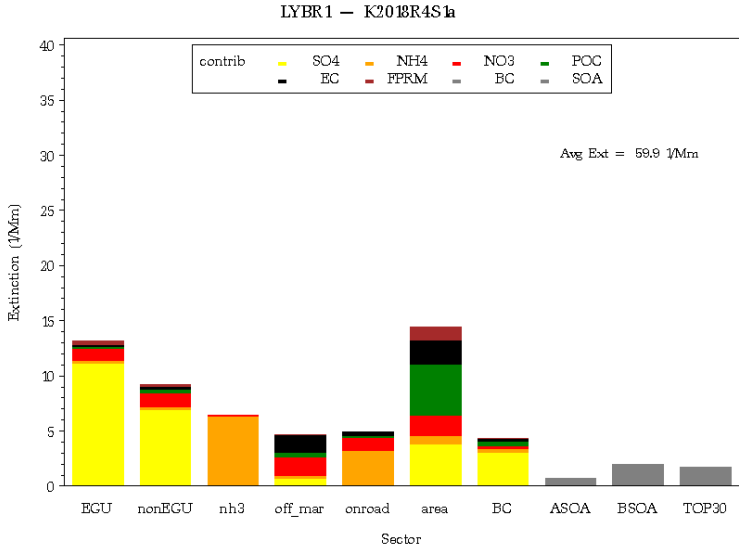
Lye Brook, Vermont

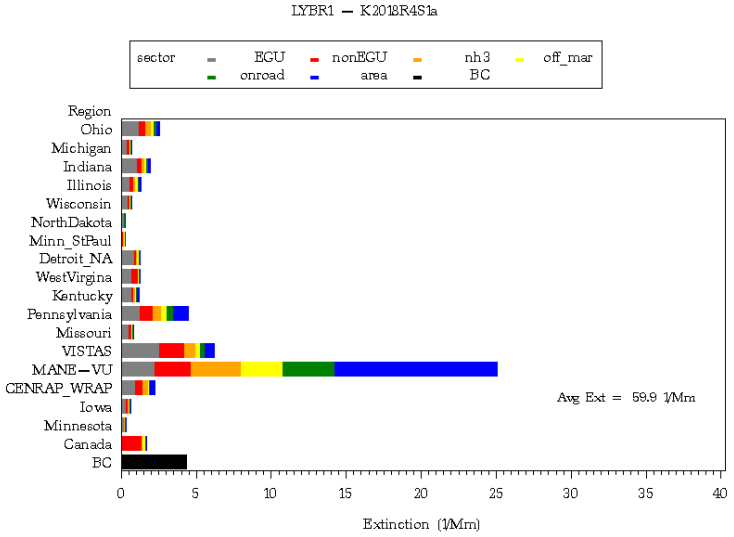
2005 (Round 5)



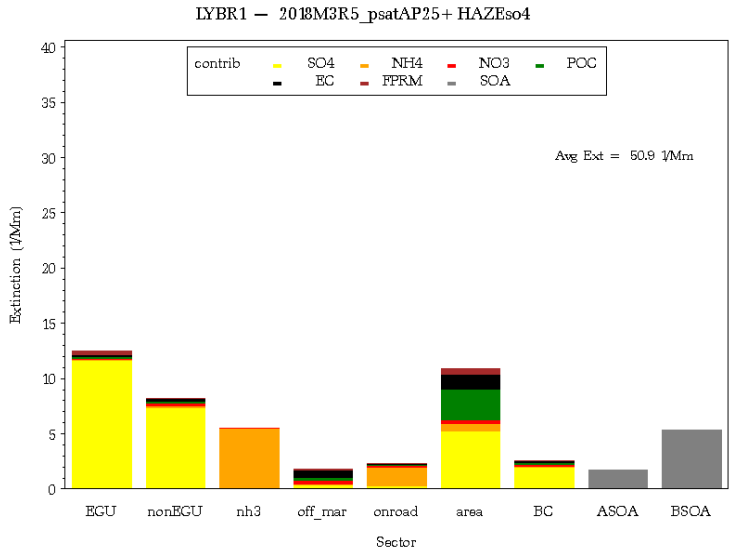


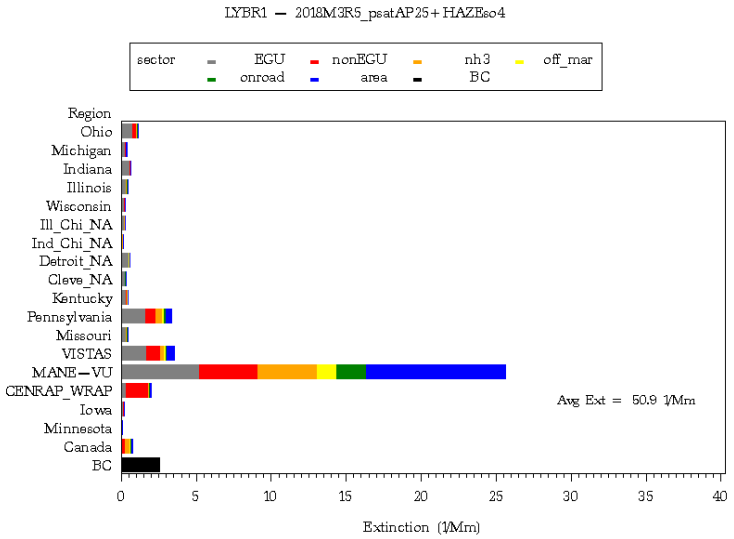
2018 (Round 4)





2018 (Round 5)





APPENDIX I

Lake Michigan Air Directors Consortium (LADCO) Round 5 Modeling Technical Support Document (Round 5 Photochemical Modeling Based on "Base M" Emissions inventory, revised version of "Base K")

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Base M Strategy Modeling: Emissions (Revised)

The purpose of this document is to summarize the emission estimates prepared for LADCO's latest (Base M) 2005 base year and 2008, 2009, 2012, and 2018 future year modeling. Base year emissions by state and source sector for Base K (2002) and Base M (2005) are compared in Figure 1. A more detailed state and source sector summary is provided in Attachment 1. Additional emission reports are available on the LADCO website: http://www.ladco.org/tech/emis/r5/round5_reports.htm.

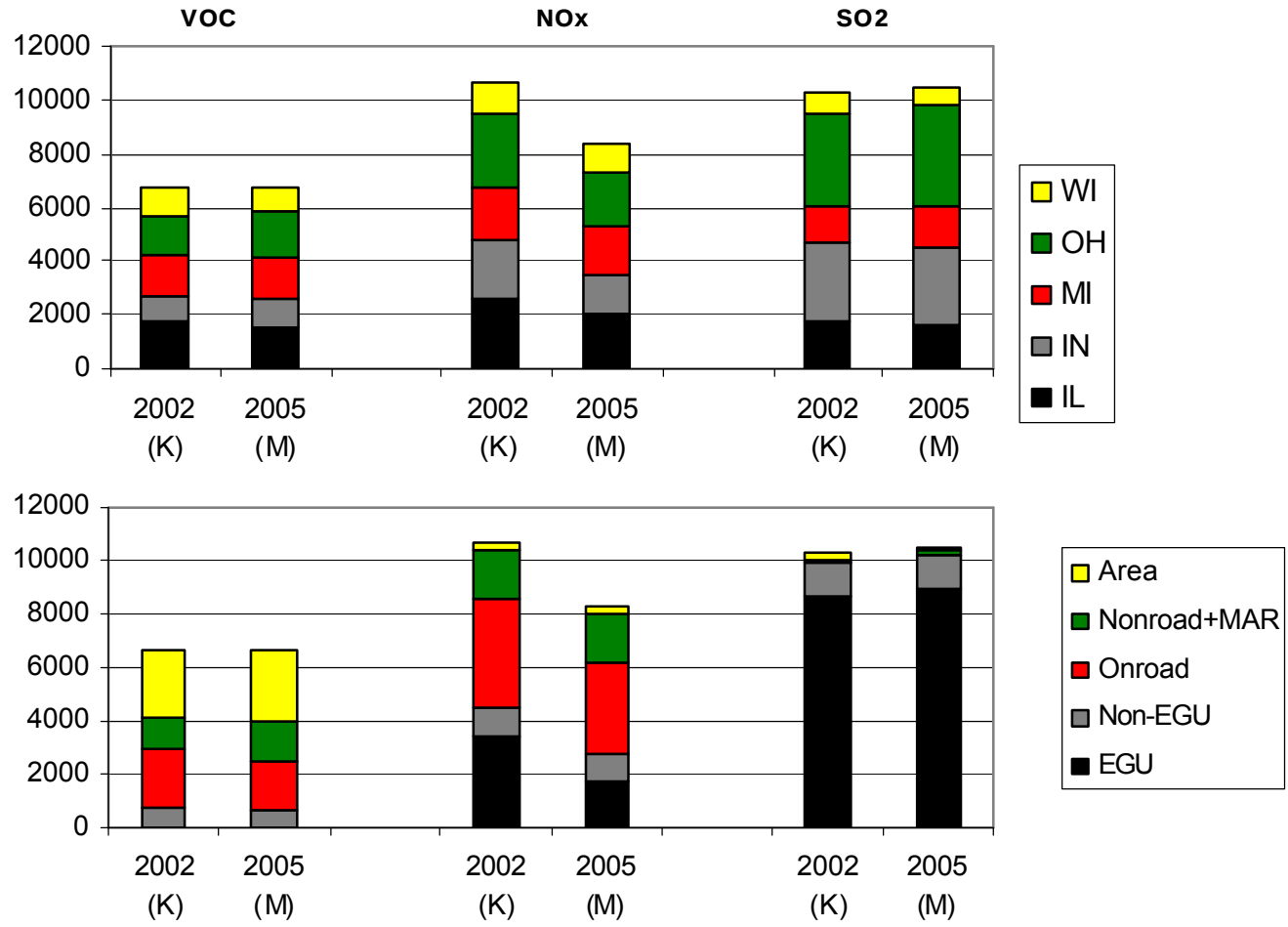


Figure 1. Base K and Base M Emissions for 5-State LADCO Region: VOC, NOx, and SO2 (TPD, July weekday)

Base Year Emissions

In mid-2006, LADCO completed modeling analyses for a 2002 base year and several future year control strategies (LADCO, 2006a and LADCO, 2006b). Following those analyses, a decision was made to conduct additional modeling using a more current base year (2005). Examination of multiple base years provides for a more complete technical assessment. All modeling was conducted in accordance with USEPA modeling guidelines (USEPA, 2007).

For on-road, ammonia, and biogenic sources, 2005 emissions were estimated by emission models. For other sectors in the LADCO States, 2005 emissions were either supplied by a contractor (railroads and commercial marine) or by the States (point sources, area sources, and aircraft). For other sectors in non-LADCO States, a contractor obtained the latest base (2002) and future year emission files (2009, 2018) from the other Regional Planning Organizations (RPOs) (Alpine, 2007a). Specifically, the following versions of these emissions files were used: MANE-VU: Version 3.1, WRAP: Pre2002d, CENRAP: Base F, and VISTAS: Base F. The 2005 emissions were then estimated by linearly interpolating between the 2002 and 2009 emissions.

Further discussion of the development of the 2005 base year emissions is provided below:

On-Road: CONCEPT was run by a contractor using transportation data (e.g., VMT and vehicle speeds) for 24 networks supplied by the state and local planning agencies in the LADCO States and Minnesota (Environ, 2008). These data were first processed with T3 (Travel Demand Modeling [TDM] Transformation Tool) to provide input files for CONCEPT. For some networks, the VMT outputs from T3 were adjusted to match 2005 HPMS data. CONCEPT was then run with meteorological data for a July and January weekday, Saturday, and Sunday (July 15 – 17 and January 16 – 18) to produce link-specific, hourly emission estimates. A spatial plots of emissions for July 15 are provided in Figure 2.

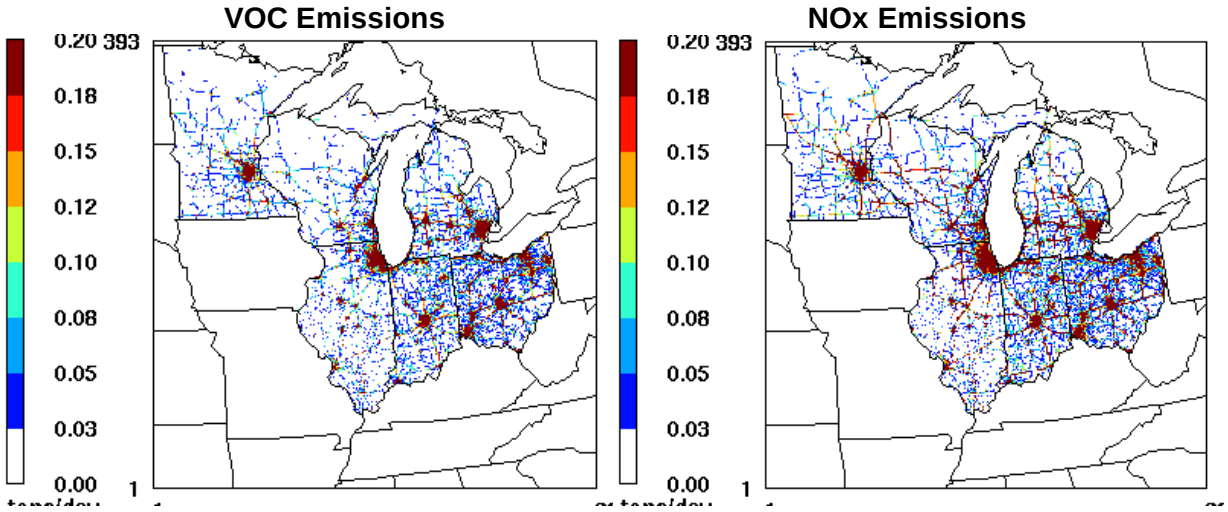


Figure 2. July 15, 2005 motor vehicle emissions for VOC (left) and NOx (right)

For the non-LADCO States, CONCEPT was run by a contractor using RPO-based HPMS county-level data (2002 and 2009) and MOBILE6 inputs (2002) compiled by another contractor (Environ, 2008). HPMS VMT for 2005 were generated by linearly interpolating between the 2002 and 2009 data. The 2002 MOBILE6 inputs were used for the 2005 modeling, with a few adjustments (e.g., fuel sulfur content was set to 30 ppm, as required by the Tier 2/low sulfur regulations). Meteorological data for a July and January weekday, Saturday, and Sunday (July 15 – 17 and January 16 – 18) were used.

For other months (for both LADCO and non-LADCO States), weekday, Saturday, and Sunday emissions were linearly interpolated based on the January and July emissions.

Off-Road: NMIM2005 was run by Grant Hetherington (Wisconsin DNR) to produce emissions for most off-road sectors for the LADCO States plus Minnesota, Iowa, and Missouri. Improved model inputs included local data for construction and agricultural equipment prepared by a contractor were incorporated (E.H. Pechan, 2004), and 2005 gasoline parameters. (Note, model updates prepared by AIR to address evaporative emissions were not included.)

EMS was run by LADCO using Grant Hetherington's NMIM2005 data and, for the non-LADCO States, using emission files supplied by Alpine based on data from the other RPOs to produce weekday, Saturday, and Sunday emissions for each month.

Additional off-road sectors (i.e., commercial marine, aircraft, and railroads [MAR]) were handled separately. Aircraft emissions were supplied by the LADCO States. Updated information for railroads and commercial marine for the LADCO States was prepared by a contractor (Environ, 2007a and Environ 2007b). Table 1 compares the new 2005 emissions with the previous 2002 emission estimates. The new 2005 emissions reflect substantially lower commercial marine emissions and lower locomotive NOx emissions.

EMS was run by LADCO using the contractor and state data and, for the non-LADCO States, using emission files supplied by Alpine based on data from the other RPOs to produce weekday, Saturday, and Sunday emissions for each month.

Table 1. Locomotive and Commercial Marine Emissions for 2002 and 2005 Base Year

	Railroads (TPY)			Commercial Marine (TPY)	
	2002	**2005**		**2002**	**2005**
VOC	7,890	7,625		1,562	828
CO	20,121	20,017		8,823	6,727
NOx	182,226	145,132		64,441	42,336
PM	5,049	4,845		3,113	1,413
SO2	12,274	12,173		25,929	8,637
NH3	86	85		----	----

Area: EMS was run by LADCO using 2005 data supplied by the LADCO States and, for the non-LADCO States, using emission files supplied by Alpine based on data from the other RPOs to produce weekday, Saturday, and Sunday emissions for each month. Special attention was given to two source categories: industrial adhesive and sealant solvent emissions and outdoor wood boilers.

> Industrial Adhesives and Sealants: The NEI shows this to be a large VOC emissions category in the LADCO States (i.e.., 50,000 TPY) USEPA subsequently determined that "(f)or the Region V states, we no longer believe that there are any activities in the Industrial Adhesives and Sealants category (SCC 2440020000) that have not been inventoried either in the point source Industrial Adhesives and Sealants category or under the Consumer and Commercial Adhesives and Sealants nonpoint category (SCC 2460600000 - all adhesives and sealants)." (USEPA, 2007b) Consequently, this category was omitted from the 2005 regional emissions inventory.

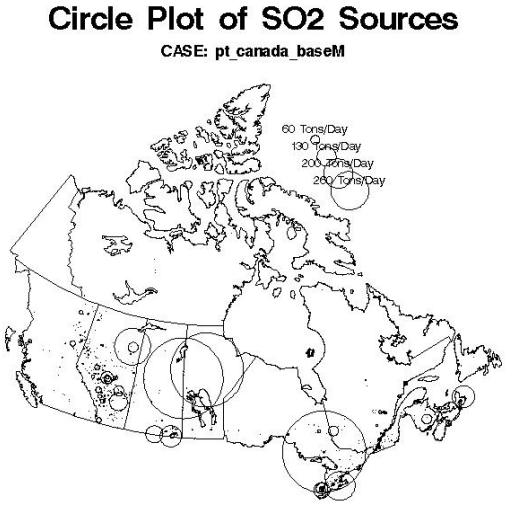
Outdoor Wood Boilers: Over the past several years, the installation and operation of outdoor wood boilers for residential use has increased dramatically in many northern states. Relying on an emission estimation methodology prepared by Bart Sponseller (WDNR, 2006), emissions were calculated by the other states for this category.

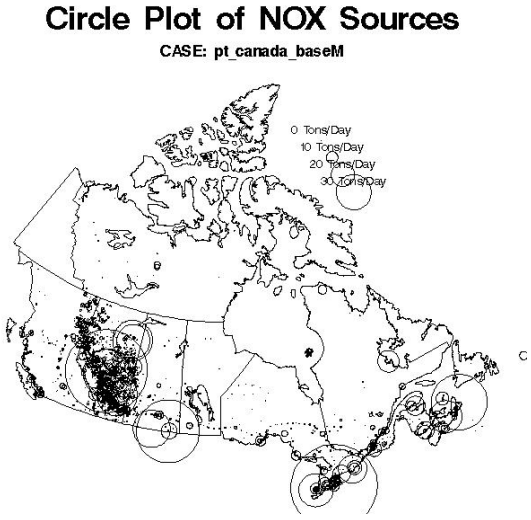
EGU Point:EMS was run by LADCO using 2005 data supplied by the LADCO States and, for the non-LADCO States, using emission files supplied by Alpine based on data from the other RPOs to produce weekday, Saturday, and Sunday emissions for each month. 2005 EGU emissions were temporalized for modeling purposes using profiles prepared by Scott Edick (Michigan DEQ) based on CEM data for the period 2004-2006. Profiles were generated for monthly weekday/Saturday/Sunday based on the median hourly emissions for that month, day, and hour of the day for the three years. Over 90% of NOX and SO2 emissions from EGUs in the LADCO states were assigned profiles. In non-Ladco states, the annual EGUs emissions were replaced with the 2005 sum of hourly emissions for all 365 days.

Non-EGU Point: EMS was run by LADCO using 2005 data supplied by the LADCO States and, for the non-LADCO States, using emission files supplied by Alpine based on data from the other RPOs to produce weekday, Saturday, and Sunday emissions for each month. EGUs were removed from this point source file.

Other improvements to the base year inventory included:

Canadian Emissions: Previous modeling inventories for Canadian sources were flawed due to problems with emissions (e.g., LADCO inventories omitted ammonia emissions) or stack parameters (e.g., VISTAS inventories failed to include proper stack parameters, resulting in emissions getting dumped in the surface layer of the model). For Base M, Scott Edick (Michigan DEQ) processed the 2005 Canadian National Pollutant Release Inventory (NPRI – see http://www.ec.gc.ca/pdb/npri/). Specifically, a subset of the NPRI data which are relevant to the air quality modeling were reformatted. A number of emission reports are available on the LADCO website (http://www.ladco.org/tech/emis/basem/canada/index.htm). Circle plot of point source emissions are presented in Figure 3.





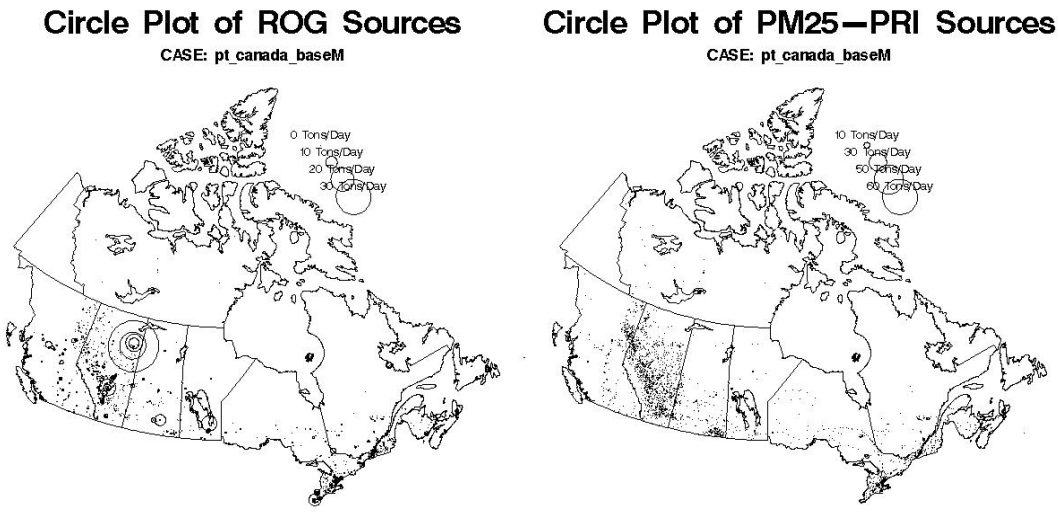


Figure 3. Base year emission plots for Canada

Biogenic Emissions: A contractor provided an updated version of the CONCEPT/MEGAN (Model of Emissions of Gases and Aerosols from Nature – see http://bai.acd.ucar.edu/Megan/) biogenics model, which was used to produce base year biogenic emission estimates (Alpine, 2007b). MEGAN includes functions for soil moisture plant stress, a more complete canopy model, full plant growth cycle emissions calculations, and state of the science emission rates.

Subsequent to deliver of the updated CONCEPT/MEGAN code, it was found that more recent data sets and model formulations were available. For the purposes of the Round 5 modeling, LADCO simply scaled the emission estimates from the updated code to reflect these newer data. This resulted in lower emissions for several organic aerosol species and NOx

Compared to the EMS/BIOME emissions used for Base K, there is more regional isoprene with MEGAN (see Figure 4). Also, with the secondary organic aerosol updates to the CAMx air quality model, Base M includes emissions for monoterpenes and sesquiterpenes, which are precursors of secondary $PM_{2.5}$ organic carbon mass.

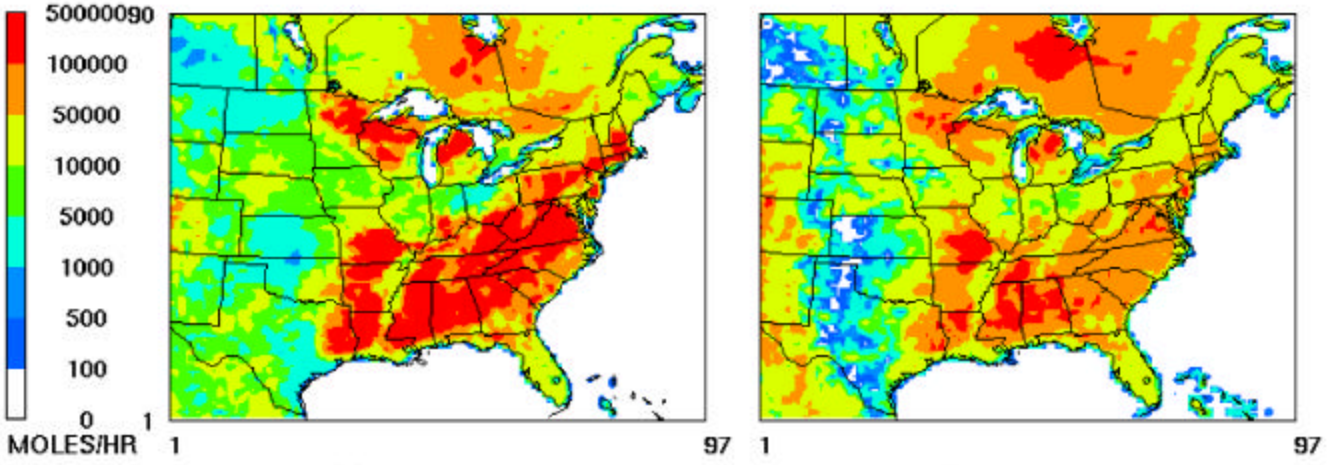


Figure 4. Isoprene emissions for Base M (left) v. Base K (right)

Ammonia Emissions: The CMU-based 2002 (Base K) annual ammonia emissions were projected to 2005 using growth factors from the Round 4 emissions modeling. These annual emissions were then adjusted by applying monthly temporal factors based on the process-based ammonia emissions model (http://www.conceptmodel.org/nh3/nh3_index.html). The model was run for the following list of model farms using 2002 meteorological data: Dairy (California, Wisconsin), Swine (Iowa, Wisconsin), and Beef (Texas, Washington, Wisconsin). Because the model was not complete for the poultry housing model, swine was use in its place given that both use confined operations.

Each model farms' emissions were used to generate monthly average day emissions and a monthly profile. The profiles were applied to geographies most associated with that farm type (e.g., all LADCO states used the Wisconsin farm results). The following figure shows the daily variation in emissions for the model farms.

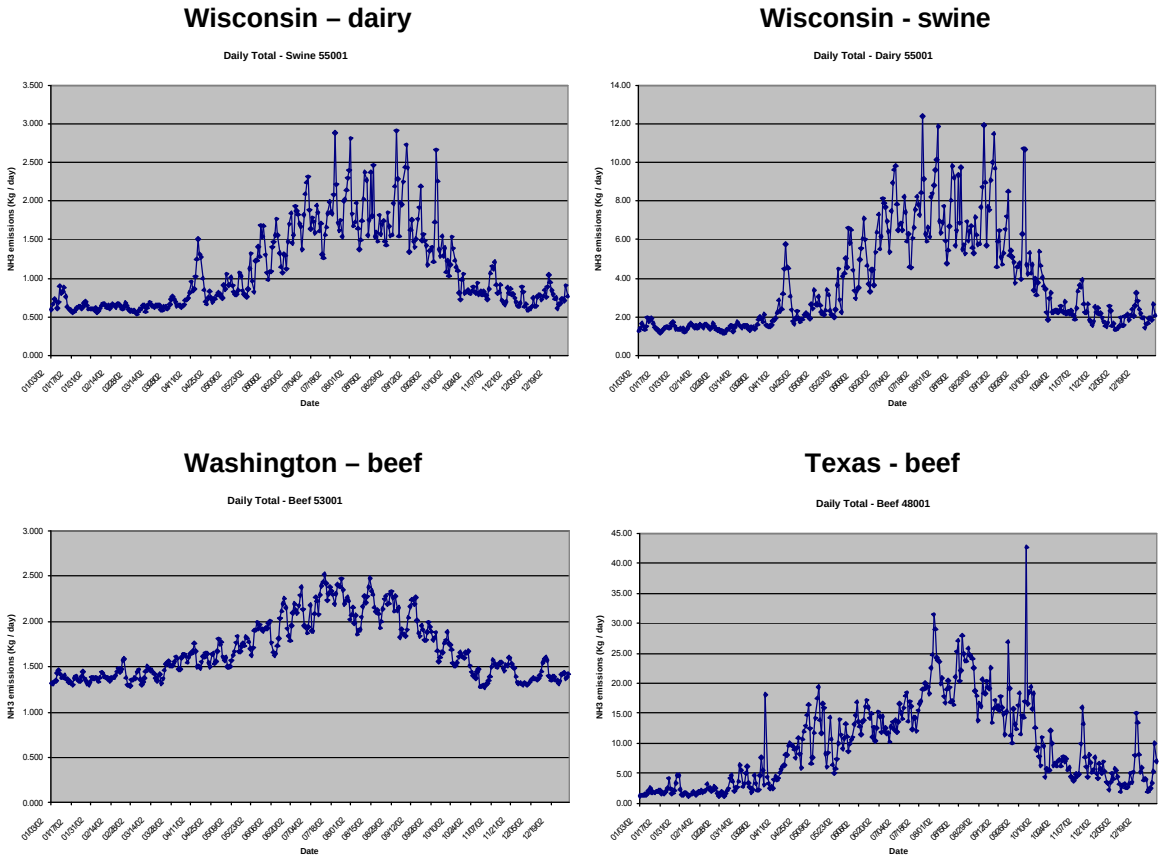


Figure 5. Daily emissions for 2002 for various model farms

A plot of the resulting average daily emissions by state and month is provided in Figure 6.

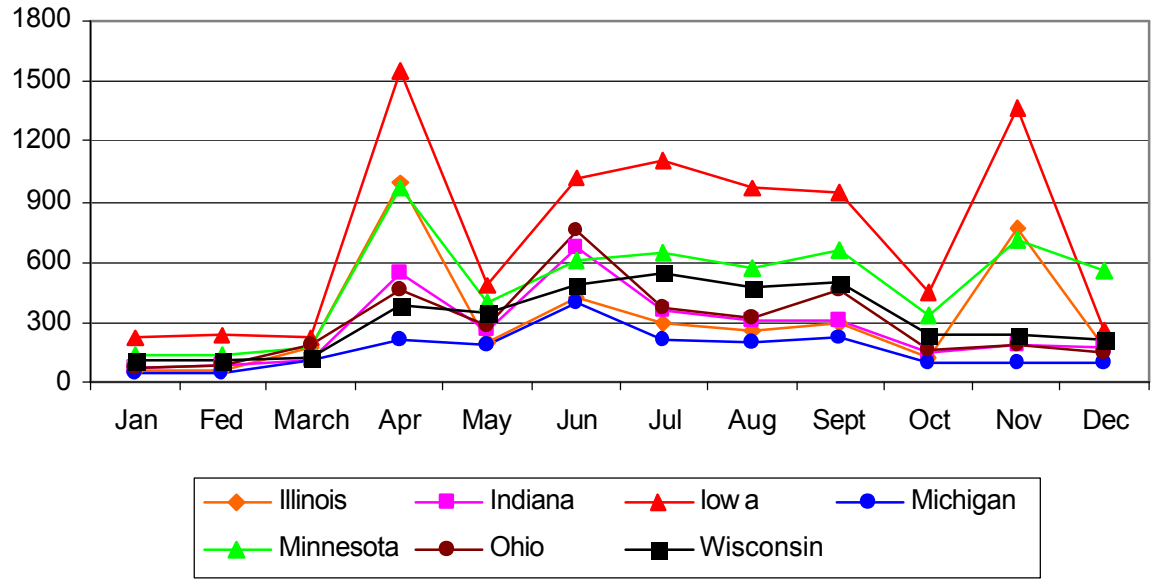


Figure 6. Average daily ammonia emissions for Midwest States by month for 2005

Fires: For Base K, a contractor (EC/R, 2004) developed a 2001, 2002, and 2003 fire emissions inventory for eight Midwest States (five LADCO states plus Iowa, Minnesota, and Missouri), including emissions from wild fires, prescribed fires, and agricultural burns. Projected emissions were also developed for 2010 and 2018 assuming "no smoke management" and "optimal smoke management" scenarios. An early model sensitivity run showed very little difference in modeled $PM_{2.5}$ concentrations. Consequently, the fire emissions were not included in subsequent modeling runs (i.e., they were not in the Base K or Base M modeling inventories).

Future Year Emissions

Complete emission inventories were developed for two future years: 2009 and 2018[1]. Source sector emission summaries for the base years (2002 – Base K and 2005 – Base M) and future years are shown in Figure 7. A more detailed state and source sector summary is provided in Attachment 1. Additional emission reports are available on the LADCO website (http://64.27.125.175/tech/emis/r5/round5_reports.htm.

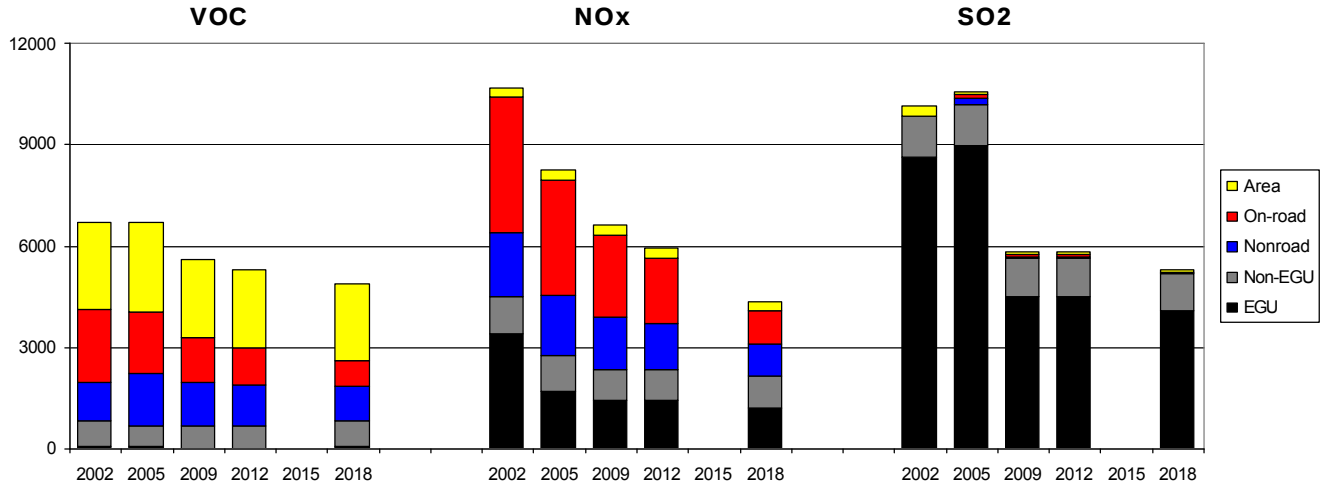


Figure 7. Base year and future year emissions for 5-State LADCO Region (TPD, July weekday)

[1] A 2008 proxy inventory was prepared to support a preliminary 2008 modeling analysis to assess attainment for the basic nonattainment areas (i.e, for areas with a 2009 attainment date, the appropriate panning year is 2008). This inventory reflects the following assumptions:

On-road: scale 2005 base year emissions using the Base K 2002 – 2009 trend (except for the Cincinnati-Dayton area, where 2008 emissions were generated using CONCEPT and 2008 data supplied by the local planning agency)

Off-road and area: scale 2005 base year emissions using the Base K 2002-2009 trend

Point – EGU: use 2005 base year emissions, with slight adjustment (-10%)

Point – Non-EGU: use 2005 base year emissions (note: Base K 2002-2009 trend suggests little change)

Biogenics: use new 2005 base year emissions

A 2012 proxy inventory was prepared to support a preliminary 2012 modeling analysis to assess the effect of further emission reductions from existing controls. This inventory was derived by interpolating between 2009 and 2018 emissions for all sectors, except point sources (for which, the 2009 emissions were used).

For on-road, off-road, and EGU sources, the future year emissions were estimated by models (i.e., CONCEPT, NMIM2005, and IPM, respectively) and then processed by LADCO with EMS. For other sectors (area, MAR, and non-EGU point sources), the future year emissions for the LADCO States were derived by applying growth and control factors to the base year inventory. These factors were developed by a contractor (E.H. Pechan, 2007). Growth factors were based initially on EGAS (version 5.0), and were subsequently modified (for select, priority categories) by examining emissions activity data. For the non-LADCO States, future year emission files were supplied by Alpine based on data from the other RPOs. Due to a lack of information on future year conditions, the biogenic VOC and NOx emissions, and all Canadian emissions were assumed to remain constant between the base year and future years.

A "base" control scenario was prepared for each future year based on the following "on the books" controls (E.H. Pechan, 2007):

On-Highway Mobile Sources

- Federal motor vehicle emission control program, low sulfur gasoline, and ultra-low sulfur diesel fuel
- Inspection/Maintenance programs (nonattainment areas)
- Reformulated gasoline (nonattainment areas)

Off-Highway Mobile Sources

- Federal control programs incorporated into NONROAD model (e.g., nonroad diesel rule), plus the evaporative Large Spark Ignition and Recreational Vehicle standards
- Heavy-duty diesel (2007) engine standard/Low sulfur fuel
- Federal railroad/locomotive standards
- Federal commercial marine vessel engine standards

Area Sources

- Consumer solvents
- AIM coatings
- Aerosol coatings
- Portable fuel containers

Power Plants

- Title IV (Phases I and II)
- NOx SIP Call
- Clean Air Interstate Rule
- Clean Air Mercury Rule

Other Point Sources

- VOC 2-, 4-, 7-, and 10-year MACT standards[2]
- Combustion turbine MACT
- Consent decrees (refineries, ethanol plants, and ALCOA)[3]

[2] E.H. Pechan's original control file included EPA-default control factor information. Alternative control factors were developed by Wisconsin for a few MACT categories, and were also applied to the other four LADCO States.

- Other (Illinois and Ohio NOx RACT[4], and BART in IN and WI)

Further discussion of the development of the future year emissions is provided below:

On-Road: Similar to the base year modeling, CONCEPT was run using transportation data (e.g., VMT and vehicle speeds) supplied by the state and local planning agencies for 2009 and 2018 (Environ, 2008). CONCEPT was only run with meteorological data for a July weekday (July 15). The emissions for Saturday and Sunday were derived by using scaling factors based on the 2005 emissions. The state-level emissions for the five LADCO States plus Minnesota are summarized in Table 2[5].

For the non-LADCO States, CONCEPT was run by Environ using HPMS county-level data and MOBILE6 inputs compiled by another contractor for VISTAS. Note, the emissions modeling for IA, MO, and OK was redone for 2009 to reflect the state-developed registration distribution data. (The initial modeling for 2009 used national default values for registration distribution assumed by VISTAS' contractor. CENRAP's contractor developed emissions inventories for 2002 and 2018 using the state-developed data. For consistency, Environ's remodeling for these three states for 2009 also used the state-developed data.) Meteorological data for a July weekday (July 15) were used. The emissions for Saturday and Sunday were derived by using scaling factors based on the 2005 emissions.

For other months (for both LADCO and non-LADCO States), January weekday, Saturday, and Sunday emissions were derived based on the July:January ratios for 2005, and then the weekday, Saturday, and Sunday emissions for other months were linearly interpolated based on the January and July emissions.

[3] E.H. Pechan's original control file included control factors for three sources in Wayne County, MI. These control factors were not applied in the regional-scale modeling to avoid double-counting with the State's local-scale analysis for PM2.5.

[4] WI believes that NOx RACT for their sources is already included in the 2005 basecase and EGU "will do" scenario, and IN provided NOx RACT information for inclusion as a no-EGU "may do" scenario.

[5] For northeastern IL (CATS region), 2009 and 2018 emissions were increases by 9% and 8%, respectively, to reflect newer transportation modeling by CATS.

Table 2. Summary of On-road Emissions (TPD – July 15, 2005)

Year	State	CO-tpd	TOG-tpd	NOx-tpd	PM2.5-tpd	SO2-tpd	NH3-tpd	Sum of VMT
2005	IL	3,684.3	341.5	748.2	12.9	9.6	35.9	344,087,819.6
	IN	3,384.9	282.0	541.1	8.9	11.1	25.7	245,537,231.9
	MI	4,210.3	351.9	722.0	12.4	13.9	35.3	340,834,025.9
	MN	2,569.1	218.7	380.5	6.3	7.6	17.7	170,024,599.7
	OH	6,113.4	679.8	933.6	16.2	18.8	36.5	360,521,068.6
	WI	2,206.0	175.1	457.5	7.8	9.2	19.7	189,123,964.3
Total		22,168.0	2,049.0	3,782.9	64.5	70.2	170.8	1,650,128,709.9
2009	IL	2,824.4	268.0	527.8	10.1	4.2	38.9	372,132,591.1
	IN	2,839.5	234.9	401.9	6.7	2.8	26.1	249,817,026.3
	MI	3,172.0	269.2	500.9	9.2	4.0	37.1	356,347,010.5
	MN	2,256.8	206.3	307.5	5.1	2.3	21.5	204,443,017.8
	OH	4,619.2	423.7	693.5	11.8	4.7	39.5	387,428,127.2
	WI	1,673.4	119.4	322.1	5.7	2.3	20.6	197,729,964.9
Total		17,385.3	1,521.5	2,753.6	48.7	20.3	183.6	1,767,897,737.8
2018	IL	2,084.7	151.5	200.7	6.3	3.7	43.1	413,887,887.3
	IN	2,217.3	138.4	173.0	4.4	2.6	30.2	288,042,232.1
	MI	2,434.3	163.5	204.1	5.9	3.6	40.5	388,128,431.8
	MN	1,799.6	123.1	137.1	3.6	2.2	24.9	237,022,213.7
	OH	3,361.5	242.5	274.1	6.8	4.0	43.1	421,694,093.4
	WI	1,255.5	68.4	138.5	3.9	2.0	22.2	218,277,167.5
Total		13,152.9	887.5	1,127.5	30.8	18.1	203.9	1,967,052,025.8

EGU Point: Future year emissions were based on EPA's IPM3.0 modeling[6]. Three CAIR scenarios were addressed:

5a: EPA's IPM3.0 was assumed as the future year base for EGUs.

5b: EPA's IPM3.0, with several "will do" adjustments identified by the States. These adjustments should reflect a legally binding commitment (e.g., signed contract, consent decree, or operating permit).[7]

5c: EPA's IPM3.0, with several "may do" adjustments identified by the States. These adjustments reflect less rigorous criteria, but should still be some type of public reality (e.g., BART determination or press announcement).

Table 3 summarizes the SO2 and NOx emissions for the three scenarios. The individual facilities affected by the "will do" and "may do" adjustments are identified in Attachment 2. The net effect of these adjustments is a small increase in regional SO2 and NOx emissions.

Based on initial discussions with USEPA, a decision was made to use the 2010 IPM emissions in the 2009 modeling. USEPA subsequently insisted that 2009 modeling must represent 2009 conditions. Because 2009 and 2010 EGU NOx emissions are expected to be similar (note: CAIR Phase I compliance date for NOx is 2009), the Round 5.1 ozone modeling was not redone.

USEPA believes that 2009 and 2010 EGU SO2 emissions may be significantly different (note: CAIR Phase I compliance date for SO2 is 2010). In particular, USEPA noted that information on projected scrubber installations identifies several facilities are not expected to be completed until 2010. A model sensitivity run was conducted with adjusted (higher) EGU SO2 emissions.

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[6] The second set of new IPM runs by EPA were used. These runs were performed at the request of the RPOs and reflect the addition of run years 2012 and 2018, and the use of four load segments for 2032 to decrease model size (instead of six segments). Comparing the results in this run with EPA's initial v3.0, showed small differences Below is a quick summary of the run year differences.

EPA Base Case for IPM v.3.0
2010: 2009-2012
2015: 2013-2017
2020: 2018-2022
2025: 2023-2027
2032: 2028-2035

Base Case RPO Run for IPM v3.0 (added 2012 and 2018 run years, 2020 run year merged with the 2025 run year, and four load segments used for the 2032 run year)
2010: 2009-2011
2012: 2012-2012
2015: 2013-2017
2018: 2018-2019
2025: 2020-2028
2032: 2029-2035

[7] Scenario 5b and 5c also reflect changes in Minnesota, Missouri, and North Dakota.

Table 4 provides information from USEPAs Clean Air Markets Division (CAMD) on scrubber installation dates. This information is based on various sources, including company announcements, consent decrees, vendors, and organizations that track scrubber installations. While there may be uncertainty in any projection of control installations, USEPA considers these adequate projections for SIP planning purposes.

USEPA identified six plants which: (1) are projected in IPM3.0 to have scrubbers in place by 2010 (or 2011), but will not be completed by 2009, and (2) are most likely to impact $PM_{2.5}$ air quality in the upper Midwest (see highlighting in Table 4). To reflect uncontrolled (2009) emissions for those facilities (and units), LADCO substituted actual 2005 emissions for the IPM3.0 projected 2010 emissions. The revised (2009) SO2 emissions for the six facilities (see Table 5) represent a 5-6% increase in domainwide SO2 emissions.

Table 3. Comparison of EGU Emissions for Base (5a), Will Do (5b), and Will Do (5c) Scenarios

	2010				2018		
SO2	**5a**	**5b**	**5c**		**5a**	**5b**	**5c**
IL	958	881	881		869	433	433
IN	1033	1318	1318		1036	1194	1194
MI	667	667	667		725	725	725
OH	1326	1410	1410		983	1127	1127
WI	460	460	421		435	499	235
	4444	4736	4697		4048	3978	3714
MN	162	148	148		187	167	157
NOx	**5a**	**5b**	**5c**		**5a**	**5b**	**5c**
IL	275	247	247		224	195	195
IN	370	372	372		255	266	266
MI	242	242	242		243	243	243
OH	281	305	305		285	310	310
WI	165	164	155		176	172	145
	1333	1330	1321		1183	1186	1159
MN	116	142	142		132	157	125

Table 4. Facilities Anticipating SO2 Controls in 2009 and 2010

State Name	Plant Name	UniqueID_Final	ORIS Code	Unit ID	Capacity MW	Scrubber OnlineYear	Scrubber OnlineMonth
Alabama	Barry	3_B_5	3	5	768	2010	
Alabama	E C Gaston	26_B_5	26	5	861	2010	
Arizona	Cholla	113_B_3	113	3	271	2009	
Florida	Crystal River	628_B_4	628	4	720	2010	
Florida	Crist	641_B_6	641	6	302	2010	
Florida	Crist	641_B_7	641	7	477	2010	
Florida	Crystal River	628_B_5	628	5	717	2009	5
Florida	Deerhaven Generating Station	663_B_B2	663	B2	228	2009	5
Georgia	Bowen	703_B_1BLR	703	1BLR	713	2010	
Georgia	Wansley	6052_B_2	6052	2	892	2009	5
Georgia	Bowen	703_B_2BLR	703	2BLR	718	2009	4
Indiana	Clifty Creek	983_B_1	983	1	217	2010	
Indiana	Clifty Creek	983_B_2	983	2	217	2010	
Indiana	Clifty Creek	983_B_3	983	3	217	2010	
Indiana	Clifty Creek	983_B_4	983	4	217	2010	
Indiana	Clifty Creek	983_B_5	983	5	217	2010	
Indiana	Clifty Creek	983_B_6	983	6	217	2010	
Indiana	Warrick	6705_B_4	6705	4	300	2010	
Kentucky	Big Sandy	1353_B_BSU2	1353	BSU2	800	2009	11
Kentucky	E W Brown	1355_B_1	1355	1	94	2009	1
Kentucky	E W Brown	1355_B_2	1355	2	160	2009	1
Kentucky	E W Brown	1355_B_3	1355	3	422	2009	1
Kentucky	H L Spurlock	6041_B_1	6041	1	315	2009	
Maryland	Brandon Shores	602_B_1	602	1	643	2010	
Maryland	Brandon Shores	602_B_2	602	2	643	2010	
Maryland	Chalk Point LLC	1571_B_1	1571	1	341	2010	
Maryland	Chalk Point LLC	1571_B_2	1571	2	342	2010	
Maryland	Dickerson	1572_B_1	1572	1	182	2010	
Maryland	Dickerson	1572_B_2	1572	2	182	2010	
Maryland	Dickerson	1572_B_3	1572	3	182	2010	
Maryland	Morgantown Generating Plant	1573_B_1	1573	1	624	2009	
Maryland	Morgantown Generating Plant	1573_B_2	1573	2	620	2009	
Michigan	Monroe	1733_B_4	1733	4	775	2009 (2010?)	
Missouri	Sioux	2107_B_1	2107	1	497	2010	
Missouri	Sioux	2107_B_2	2107	2	497	2010	
New Jersey	PSEG Mercer Gen. Station	2408_B_1	2408	1	315.3	2010	
New Jersey	PSEG Mercer Gen. Station	2408_B_2	2408	2	309.9	2010	
New York	AES Westover	2526_B_11	2526	11	21.85	2010	
New York	AES Westover	2526_B_12	2526	12	21.85	2010	
New York	AES Westover	2526_B_13	2526	13	84	2010	
New York	AES Greenidge LLC	2527_B_4	2527	4	26.5	2010	
New York	AES Greenidge LLC	2527_B_5	2527	5	26.5	2010	
NorthCarolina	Cliffside	2721_B_1	2721	1	38	2010	

NorthCarolina	Cliffside	2721_B_2	2721	2	38	2010	
NorthCarolina	Cliffside	2721_B_3	2721	3	61	2010	
NorthCarolina	Cliffside	2721_B_4	2721	4	61	2010	
NorthCarolina	Cliffside	2721_B_5	2721	5	550	2010	
NorthCarolina	G G Allen	2718_B_1	2718	1	161.73	2009	5
NorthCarolina	Roxboro	2712_B_1	2712	1	369	2009	
NorthCarolina	G G Allen	2718_B_2	2718	2	161.73	2009	
NorthCarolina	G G Allen	2718_B_3	2718	3	259.77	2009	
NorthCarolina	G G Allen	2718_B_4	2718	4	274.77	2009	
NorthCarolina	G G Allen	2718_B_5	2718	5	265	2009	
NorthCarolina	Mayo	6250_B_1A	6250	1A	361.5	2009	
NorthCarolina	Mayo	6250_B_1B	6250	1B	361.5	2009	
Ohio	W H Sammis	2866_B_6	2866	6	630	2011	
Ohio	W H Sammis	2866_B_7	2866	7	630	2011	
Ohio	R E Burger	2864_B_7	2864	7	156	2010	
Ohio	R E Burger	2864_B_8	2864	8	156	2010	
Ohio	Kyger Creek	2876_B_1	2876	1	217	2010	
Ohio	Kyger Creek	2876_B_2	2876	2	217	2010	
Ohio	Kyger Creek	2876_B_3	2876	3	217	2010	
Ohio	Kyger Creek	2876_B_4	2876	4	217	2010	
Ohio	Kyger Creek	2876_B_5	2876	5	217	2010	
Ohio	Conesville	2840_B_4	2840	4	780	2009	4
Ohio	Bay Shore	2878_B_4	2878	4	215	2009	
Pennsylvania	Cheswick Power Plant	8226_B_1	8226	1	580	2010	
Pennsylvania	Hatfields Ferry Power Station	3179_B_1	3179	1	530	2009	1
Pennsylvania	Hatfields Ferry Power Station	3179_B_2	3179	2	530	2009	1
Pennsylvania	Hatfields Ferry Power Station	3179_B_3	3179	3	530	2009	1
Pennsylvania	Keystone	3136_B_1	3136	1	850	2009	
Pennsylvania	Keystone	3136_B_2	3136	2	850	2009	
Pennsylvania	PPL Brunner Island	3140_B_1	3140	1	321	2009	
Pennsylvania	PPL Brunner Island	3140_B_2	3140	2	378	2009	
Tennessee	Kingston	3407_B_1	3407	1	135	2010	
Tennessee	Kingston	3407_B_2	3407	2	135	2010	
Tennessee	Kingston	3407_B_3	3407	3	135	2010	
Tennessee	Kingston	3407_B_4	3407	4	135	2010	
Tennessee	Kingston	3407_B_5	3407	5	177	2010	
Tennessee	Kingston	3407_B_6	3407	6	177	2010	
Tennessee	Kingston	3407_B_7	3407	7	177	2010	
Tennessee	Kingston	3407_B_8	3407	8	177	2010	
Tennessee	Kingston	3407_B_9	3407	9	178	2010	
Tennessee	Bull Run	3396_B_1	3396	1	881	2009	1
Texas	Fayette Power Project	6179_B_1	6179	1	598	2009	
Texas	Fayette Power Project	6179_B_2	6179	2	598	2009	
Virginia	Chesterfield	3797_B_5	3797	5	310	2010	
Virginia	Yorktown	3809_B_1	3809	1	159	2010	

Table 5. Summary of Adjusted EGU SO2 Emissions (TPD)

State	Plant	2010 IPM	2005 BY
Indiana	Clifty Creek	41.41	225.32
Missouri	Ameren Sioux	22.25	141.92
Ohio	Kyger Creek	21.53	197.68
Ohio	Sammis	147.97	305.90
Pennsylvania	Cheswick	11.53	103.98
Tennessee	Kingston	41.15	155.20

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ATTACHMENT 1

Emissions Summaries

	VOC	Base M	BaseK	Base M	BaseK	BaseK	Base M		NOx	Base M	BaseK	Base M	BaseK	BaseK	Base M		SOX	Base M	BaseK	Base M	BaseK	BaseK	Base M		PM2.5	Base M	BaseK	Base M	BaseK	BaseK	Base M
July	2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018		2002	2005	2009	2009	2012	2018	2018
Nonroad																															
IL	224	321	164	257	149	130	213		324	333	263	275	224	154	155		31	33	5	5	0.6	0.4	0.4			30		24			14
IN	125	195	94	160	95	95	128		178	191	142	158	141	141	89		17	19	3	3	3	0.3	0.2			17		13			7
MI	348	414	307	350	276	222	271		205	239	159	197	133	93	112		19	22	3	3	0.5	0.3	0.3			22		18			11
OH	222	356	161	294	145	126	238		253	304	195	246	162	109	135		23	29	4	5	0.5	0.3	0.4			27		22			13
WI	214	238	194	203	175	140	157		145	157	114	129	97	69	77		13	15	2	2	0.3	0.2	0.2			14		12			7
5-State Total	1133	1524	920	1264	840	713	1007		1105	1224	873	1005	757	566	568		103	118	17	18	4.9	1.5	1.5			110		89			52
U.S. Total	8463	9815	5442	8448		5244	6581		6041	9060	6057	8120		5832	5100		505	654	117	153		104	13			573		750			475
MAR																															
IL	10	11	10	10	10	10	6		277	246	201	228	195	186	165		0	22	0	19	0	0	17			7		6			4
IN	5	5	5	5	5	5	3		123	93	89	87	87	84	65		0.2	8	0.2	7	0.2	0.2	6			2		2			2
MI	7	7	7	7	7	8	7		114	87	112	82	111	110	65		0.6	21	0.7	14	0.7	0.8	8			3		3			2
OH	8	7	8	7	8	8	5		177	134	128	126	126	122	94		0.4	14	0.3	12	0.3	0.3	10			4		4			2
WI	4	4	4	4	4	4	3		79	58	59	54	59	57	41		12.7	8	9.5	6	9.5	8.7	5			2		2			1
5-State Total	34	34	34	33	34	35	24		770	618	589	577	578	559	430		13.9	73	10.7	58	10.7	10	46			18		17			11
U.S. Total	307	317	321	157	329	346	334		4968	4515	4002	1813	3964	3919	3812		620	512	509	122	509	503	290			147		57			165
OtherArea																															
IL	679	675	688	594	700	738	582		62	48	68	48	70	73	49		11	11	12	16	12	13	16			40		64			69
IN	354	391	365	358	373	398	384		62	56	65	58	67	69	59		158	32	150	32	151	153	32			2		2			2
MI	518	652	516	562	520	541	549		49	49	52	50	53	54	51		71	29	68	29	68	68	28			111		114			120
OH	546	604	550	506	558	593	487		50	93	59	108	60	62	108		22	6	34	15	35	35	14			19		35			34
WI	458	315	467	290	474	506	293		32	37	34	37	34	35	37		9	17	9	13	10	10	13			11		12			12
5-State Total	2555	2637	2586	2310	2625	2776	2295		255	283	278	301	284	293	304		271	95	273	105	276	279	103			183		227			237
U.S. Total	17876	21093	18638	18683		20512	24300		3856	4899	4100	4220		4418	5357		2075	2947	2062	2559		2189	2709			2735		2621			2570
On-Road																															
IL	446	341	314	268	260	197	151		890	748	578	528	474	300	201			9		4			3			13		10			6
IN	405	282	237	235	193	150	138		703	541	425	402	313	187	173			11		3			2			9		7			2
MI	522	351	335	269	303	217	163		926	722	680	501	619	385	204			14		4			3			12		9			3
OH	574	680	365	424	340	238	242		1035	934	609	693	512	270	274			18		4			4			16		12			4
WI	238	175	144	119	117	88	68		481	457	303	322	226	118	138			9		2			2			8		6			2
5-State Total	2185	1829	1395	1315	1213	890	762		4035	3402	2595	2446	2144	1260	990			61		17			14			58		44			17
U.S. Total	14263				7825				23499				13170																		
EGU																															
IL	9	7	8	6	8	9	7		712	305	227	275	244	231	224		1310	1158	944	958	789	810	869			13		34			77
IN	6	6	6	6	7	6	6		830	393	406	370	424	283	255		2499	2614	1267	1033	1263	1048	1036			16		73			74
MI	12	6	11	4	11	12	4		448	393	218	242	219	247	243		1103	1251	1022	667	1031	1058	725			15		25			29
OH	5	4	6	5	7	7	6		1139	408	330	280	322	271	285		3131	3405	1463	1326	994	701	983			28		94			80
WI	3	5	3	2	4	4	3		293	213	146	165	139	147	177		602	545	512	460	492	500	435			0		22			25
5-State Total	35	28	34	23	37	38	26		3422	1712	1327	1332	1348	1179	1184		8645	8973	5208	4444	4569	4117	4048			72		248			285
U.S. Total	214	140	195	124	197	215	138		14371	10316	7746	7274	7721	7007	6095		31839	34545	20163	16903	17629	14727	14133			685		1131			1571
Non-EGU																															
IL	313	221	286	218	305	350	258		356	330	334	218	338	343	235		373	423	251	335	257	249	346			16		17			19
IN	150	130	160	137	170	199	167		238	179	212	175	216	225	178		292	218	270	216	274	290	180			35		36			44
MI	123	116	115	119	122	139	140		216	240	208	242	214	229	271		162	158	166	148	171	185	163			20		21			25
OH	77	84	75	87	79	90	104		177	175	157	166	160	167	178		240	289	231	288	210	216	293			27		28			33
WI	88	84	97	87	104	120	106		98	97	91	93	92	94	81		163	156	154	152	155	156	85			0		0.1			0.1
5-State Total	751	635	733	648	780	898	775		1085	1021	1002	894	1020	1058	943		1230	1244	1072	1139	1067	1096	1067			98		102			121
U.S. Total	4087	3877	4409		4700	5378			6446	6730	6129		6435	6952			5759	5630	6093		6340	6970						1444			1777
IL	1681	1576	1470	1353	1432	1434	1217		2621	2010	1671	1572	1545	1287	1029		1725	1656	1212	1337	1059	1072	1251			119		155			189
IN	1045	1009	867	901	843	853	826		2134	1453	1339	1250	1248	989	819		2966	2902	1690	1294	1691	1492	1256			81		133			131
MI	1530	1546	1291	1311	1239	1139	1134		1958	1730	1429	1314	1349	1118	946		1356	1495	1260	865	1271	1312	927			183		190			190
OH	1432	1735	1165	1323	1137	1062	1082		2831	2048	1478	1619	1342	1001	1074		3416	3761	1732	1650	1240	953	1304			121		195			166
WI	1005	821	909	705	878	862	630		1128	1019	747	800	647	520	551		800	750	687	635	667	675	540			35		54			47
5-State Total	6693	6687	5702	5593	5529	5350	4889		10672	8260	6664	6555	6131	4915	4319		10263	10564	6581	5781	5928	5504	5280			539		727			723

ATTACHMENT 2

"Will Do" and "May Do" EGU Facility Emissions

2009 – Difference between base (5a) and "will do" (5b) scenarios

The SAS System 09:55 Wednesday, February 27, 2008 1

polid=NOX

Obs	cntryid	stid	cyid	fcid	name	polid	aceebase	aceenew	diff
1	US	17	97	097190AAC	MIDWEST GENERAT	NOX	11.54	6.28	-5.266
2	US	17	197	197810AAK	MIDWEST GENERAT	NOX	21.11	9.46	-11.652
3	US	18	73	00008	NIPSCO - R.M. S	NOX	26.50	24.81	-1.691
4	US	18	77	00001	IKEC - CLIFTY C	NOX	11.58	16.42	4.836
5	US	18	89	00117	NIPSCO - DEAN H	NOX	20.51	19.13	-1.384
6	US	27	37	2703700003	NSP dba Xcel En	NOX	8.03	26.74	18.709
7	US	27	61	2706100004	Minnesota Power	NOX	15.43	18.40	2.969
8	US	27	163	2716300005	Xcel Energy - A	NOX	4.21	5.92	1.718
9	US	29	183	0001	AMERENUE-SIOUX	NOX	28.47	12.81	-15.658
10	US	38	55	126	Coal Creek Stat	NOX	30.49	30.36	-0.132
11	US	38	57	12	Leland Olds Sta	NOX	11.32	36.67	25.348
12	US	38	57	125	Stanton Station	NOX	6.11	6.11	0.002
13	US	38	57	13	Antelope Valley	NOX	33.00	36.39	3.385
14	US	38	57	289	Coyote	NOX	35.12	36.95	1.839
15	US	38	59	172	RM Heskett Stat	NOX	5.45	4.72	-0.727
16	US	38	65	165	M R Young Stati	NOX	6.02	71.10	65.081
17	US	39	93	0247030013	AVON LAKE POWER	NOX	3.98	20.54	16.561
18	US	39	129	0165000006		NOX	.	1.69	.
19	US	55	11	606034110	DAIRYLAND POWER	NOX	19.24	18.96	-0.279
20	US	55	21	111003090	Alliant Energy-	NOX	14.23	17.16	2.927
21	US	55	43	122014530	Alliant Energy-	NOX	7.61	7.77	0.160
22	US	55	59	230006260	WIS ELECTRIC PO	NOX	7.39	14.03	6.647
23	US	55	71	436035930	MANITOWOC PUBLI	NOX	2.06	1.80	-0.259
24	US	55	79	241007690	WIS ELECTRIC PO	NOX	15.25	15.41	0.166
25	US	55	79	241007800	WIS ELECTRIC PO	NOX	7.87	6.07	-1.801
26	US	55	117	460033090	WP & L Alliant	NOX	19.06	11.85	-7.215
27	US	55	123	663020930	DAIRYLAND POWER	NOX	10.47	8.52	-1.955
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polid							382.05	486.07	102.327

---------- polid=SO2 ----------

Obs	cntryid	stid	cyid	fcid	name	polid	aceebase	aceenew	diff
28	US	17	97	097190AAC	MIDWEST GENERAT	SO2	49.91	29.27	-20.636
29	US	17	197	197810AAK	MIDWEST GENERAT	SO2	91.90	62.70	-29.198
30	US	18	29	00002	AMERICAN ELECTR	SO2	66.34	102.72	36.389
31	US	18	43	00004	PSI ENERGY - GA	SO2	25.53	66.01	40.488
32	US	18	73	00008	NIPSCO - R.M. S	SO2	82.52	63.71	-18.817
33	US	18	147	00020	INDIANA MICHIGA	SO2	71.67	198.71	127.042
34	US	18	167	00021	PSI ENERGY - WA	SO2	76.09	175.87	99.786
35	US	27	31	2703100001	Minnesota Power	SO2	12.27	5.75	-6.512
36	US	27	61	2706100004	Minnesota Power	SO2	30.76	20.79	-9.968
37	US	27	163	2716300005	Xcel Energy - A	SO2	5.33	7.11	1.777
38	US	29	183	0001	AMERENUE-SIOUX	SO2	22.25	8.34	-13.903
39	US	38	55	126	Coal Creek Stat	SO2	27.45	75.37	47.926
40	US	38	57	12	Leland Olds Sta	SO2	108.15	126.06	17.906
41	US	38	57	125	Stanton Station	SO2	25.29	12.37	-12.922
42	US	38	57	13	Antelope Valley	SO2	26.60	43.72	17.128
43	US	38	57	289	Coyote	SO2	19.26	53.19	33.932
44	US	38	59	172	RM Heskett Stat	SO2	9.23	30.11	20.872
45	US	38	65	165	M R Young Stati	SO2	27.98	82.23	54.249
46	US	39	81	0641160017	W. H. SAMMIS PL	SO2	147.97	55.61	-92.363
47	US	39	93	0247030013	AVON LAKE POWER	SO2	7.62	127.04	119.417
48	US	39	129	0165000006		SO2	.	16.55	.
49	US	55	21	111003090	Alliant Energy-	SO2	61.97	74.80	12.822
50	US	55	43	122014530	Alliant Energy-	SO2	11.49	42.60	31.111
51	US	55	59	230006260	WIS ELECTRIC PO	SO2	7.39	12.34	4.949
52	US	55	71	436035930	MANITOWOC PUBLI	SO2	5.90	9.95	4.050
53	US	55	79	241007690	WIS ELECTRIC PO	SO2	59.72	41.19	-18.535
54	US	55	79	241007800	WIS ELECTRIC PO	SO2	38.79	21.36	-17.433
55	US	55	123	663020930	DAIRYLAND POWER	SO2	19.56	3.79	-15.772
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polid							1138.93	1569.26	413.785
							========	=======	========
							1520.97	2055.32	516.112

2009 – Difference between “will do” (5b) and “may do” (5c) scenarios

The SAS System 09:55 Wednesday, February 27, 2008 1

polid=NOX

Obs	cntryid	stid	cyid	fcid	name	polid	aceebase	aceenew	diff
1	US	19	139	70-01-011	MUSCATINE POWER	NOX	5.649	3.926	-1.7226
2	US	55	9	405031990	WI PUBLIC SERVI	NOX	9.234	7.786	-1.4476
3	US	55	11	606034110	DAIRYLAND POWER	NOX	18.957	18.994	0.0377
4	US	55	21	111003090	Alliant Energy-	NOX	17.158	17.156	-0.0021
5	US	55	25	113004430	MADISON GAS & E	NOX	3.886	2.639	-1.2470
6	US	55	43	122014530	Alliant Energy-	NOX	7.765	7.756	-0.0091
7	US	55	59	230006260	WIS ELECTRIC PO	NOX	14.034	9.826	-4.2074
8	US	55	71	436035930	MANITOWOC PUBLI	NOX	1.800	0.439	-1.3610
9	US	55	79	241007690	WIS ELECTRIC PO	NOX	15.413	15.435	0.0219
10	US	55	79	241007800	WIS ELECTRIC PO	NOX	6.068	6.072	0.0041
11	US	55	117	460033090	WP & L Alliant	NOX	11.847	11.892	0.0456
12	US	55	123	663020930	DAIRYLAND POWER	NOX	8.517	8.482	-0.0343
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polid							120.325	110.404	-9.9218

polid=SO2

Obs	cntryid	stid	cyid	fcid	name	polid	aceebase	aceenew	diff
13	US	19	139	70-01-011	MUSCATINE POWER	SO2	6.237	11.178	4.9415
14	US	55	9	405031990	WI PUBLIC SERVI	SO2	21.750	18.074	-3.6753
15	US	55	21	111003090	Alliant Energy-	SO2	74.796	74.988	0.1924
16	US	55	25	113004430	MADISON GAS & E	SO2	16.331	0.063	-16.2672
17	US	55	43	122014530	Alliant Energy-	SO2	42.604	42.640	0.0362
18	US	55	59	230006260	WIS ELECTRIC PO	SO2	12.336	9.850	-2.4867
19	US	55	71	436035930	MANITOWOC PUBLI	SO2	9.949	3.001	-6.9477
20	US	55	79	241007690	WIS ELECTRIC PO	SO2	41.189	41.210	0.0207
21	US	55	79	241007800	WIS ELECTRIC PO	SO2	21.360	21.430	0.0699
22	US	55	123	663020930	DAIRYLAND POWER	SO2	3.785	3.716	-0.0694
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polid							250.336	226.151	-24.1856
							========	=======	========
							370.662	336.554	-34.1074

Appendix I

Notice of Public Hearing &

Statement of Consideration

KENTUCKY DIVISION FOR AIR QUALITY
NOTICE OF PUBLIC HEARING
TO REVISE KENTUCKY'S STATE IMPLEMENTATION PLAN

The Kentucky Energy and Environment Cabinet will conduct a public hearing on December 15, 2010, at 6:00 p.m. (EDT) in the Conference Room of the Northern Kentucky Area Development District (NKADD), 22 Spiral Drive, Florence, Kentucky. This hearing is being held to receive comments on a proposed State Implementation Plan (SIP) revision to redesignate the Kentucky portion of the Cincinnati-Hamilton, Ohio-Kentucky-Indiana $PM_{2.5}$ nonattainment area to attainment for the 1997 annual $PM_{2.5}$ National Ambient Air Quality Standard. This revision, when approved by U.S. EPA, will redesignate Boone, Campbell, and Kenton Counties to attainment, and document that the ambient monitoring data for fine particulate matter indicates attainment of the standard.

This hearing is open to the public and all interested persons will be given the opportunity to present testimony. To assure that all comments are accurately recorded, the Division requests that oral comments presented at the hearing also be provided in written form, if possible. To be considered part of the hearing record, comments must be received by the close of the hearing. Comments should be sent to the contact person.

The full text of the proposed SIP revision is available for public inspection and copying during regular business hours (8:00 a.m. to 4:30 p.m.) at the locations listed below. Any individual requiring copies may submit a request to the Division for Air Quality in writing, by telephone, or by fax. Requests for copies should be directed to the contact person. In addition, an electronic version of the proposed SIP revision document and relevant attachments can be downloaded from the Division for Air Quality's web site at:
http://air.ky.gov/Pages/PublicNoticesandHearings.aspx

The hearing facility is accessible to people with disabilities. An interpreter or other auxiliary aid or service will be provided upon request. Please direct these requests to the contact person.

CONTACT PERSON: Susan Weaver, Internal Policy Analyst III, Division for Air Quality, 200 Fair Oaks Lane, Frankfort, Kentucky 40601. Phone (502) 564-3999; Fax (502) 564-4666; E-mail susan.weaver@ky.gov.

The Environmental and Public Protection Cabinet does not discriminate on the basis of race, color, national origin, sex, age, religion, or disability and provides, upon request, reasonable accommodation including auxiliary aids and services necessary to afford an individual with a disability an equal opportunity to participate in all services, programs, and activities.

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Ashland, KY 41102-8942

Bowling Green Regional Office
1508 Westen Avenue
Bowling Green, KY 42104-3356

Florence Regional Office
8020 Veterans Mem Dr, Suite 110
Florence, KY 41042

Frankfort Regional Office
200 Fair Oaks Ln., 3rd Floor
Frankfort, KY 40601-1758

Hazard Regional Office
233 Birch Street, Suite 2
Hazard, KY 41701-2179

London Regional Office
875 S. Main Street
London, KY 40741

Owensboro Regional Office
3032 Alvey Park Dr W, Suite 700
Owensboro, KY 42303-2191

Paducah Regional Office
130 Eagle Nest Drive
Paducah, KY 42003-0823

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LEGAL NOTICE
Queen City Self Storage, 4775 Red Bank Expressway, Cincinnati, Ohio 45227 (513) 271-5599, Fax (513) 271-5645. Sale November 23, 2010 at 10 A.M. Auction conducted by Jerry Rogers. Auctioneer selling contents on premises of delinquent accounts of parties listed below:
Carole A. Saturday, 2527 W. 74th St., Oklahoma City, OK 73159 bed, a/c unit misc., unseen items;
Michelle Banks, 930 Ellison Ave., Cinti, OH 45226 misc., household items, building supplies, Isabella Minnifield, 3185 Ferncrest Ct.#12, Cinti, OH 45211 misc. household items; Michael F. Paul, 5122 Kenwood Rd, Cinti., OH 45227, couches; Karmin Digby, PO Box 36352, Cinti, OH 45236, misc., household items; Jared McVey, 5149 Winton Rd Apt. D, Fairfield, OH 45014 & Melissa A. Barger, 4634 Carter Ave. #1, Cinti, OH 45212. 1001603827

REQUEST FOR PROPOSAL
The Kenton County Airport Board (the "Board"), owner and operator of the Cincinnati /Northern Kentucky International Airport, is requesting competitive proposals from interested parties to enter into an agreement to operate and manage an on demand taxicab service at the Cincinnati/Northern Kentucky International Airport. Proposal documents may be obtained on or after November 11, 2010 at www.cvgairport.com – Business Opportunities /Procurement/Items Out for Bid or by contacting Lisa Ransom at: (859) 767-7023 or e-mail lransom@cvgairport.com Proposals are to be submitted no later than 2:00 P.M. (EST) on December 9, 2010. A pre-proposal meeting will be held at 1:00 P.M., on Tuesday, November 23, 2010, at Administrative Offices of the Board, Terminal Building 1, Second Floor, Cincinnati/Northern Kentucky International Airport. The Board, in accordance with Title VI of the Civil Rights Act of 1964 (42 USC 2000d et seq.) and 49 CFR, Part 21, Non-Discrimination in federally assisted programs of the Department of Transportation, hereby notifies all Proposers that it will affirmatively assure that disadvantaged business enterprises are afforded full opportunity to submit proposals in response to this invitation and will not be discriminated against on the grounds of race, color, or national original in consideration for an award. The Board reserves the right to reject any and all proposals, to waive any informality in any proposal, and to negotiate with the Proposer submitting the proposal most favorable to the Board. Each Proposer is required to submit his/her proposal in the manner stated on the RFP. 1001604220

SIXTH CIRCUIT JUDICIAL COUNCIL
Office of the Circuit Executive
FOR IMMEDIATE RELEASE

Pursuant to the Bankruptcy Amendments and Federal Judgeship Act of 1984, P.L. 98-353, the Regulations of the Judicial Conference of the United States for the Selection of United States Bankruptcy Judge Nominees, and the Procedures of the Sixth Circuit Judicial Council for the Selection of Bankruptcy Judge Nominees, the Sixth Circuit Judicial Council received applications from persons interested in appointment to the bankruptcy judge position in the Southern District of Ohio, vice J. Vincent Aug.

A Merit Selection Panel considered all applications received and recommended the following four candidates to the Sixth Circuit Judicial Council for consideration for appointment to the bankruptcy judge vacancy:

Beth A. Buchanan	Waynesville, OH
Monica Villarejos Kindt	Cincinnati, OH
Jeffrey Alan Moyer	Coopersville, MI
Louis F. Solimine	Cincinnati, OH

The Sixth Circuit Judicial Council must narrow the list to three recommended candidates for this position. Under the Act, the final selection of a person for appointment as bankruptcy judge will be made by the United States Court of Appeals for the Sixth Circuit.

Any person may now submit written comments for consideration by the Judicial Council and the Court of Appeals regarding the qualifications of the above-four final nominees. Such written comments must be received in the Office of the Circuit Executive, 503 Potter Stewart United States Courthouse, 100 East Fifth Street, Cincinnati, Ohio 45202, **no later than November 22, 2010.**

Please contact Clarence Maddox, Circuit Executive, (513) 564-7200 for further information.

Issue date: November 8, 2010

KENTUCKY DIVISION FOR AIR QUALITY
NOTICE OF PUBLIC HEARING
TO REVISE KENTUCKY'S STATE IMPLEMENTATION PLAN

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CONTACT PERSON: Susan Weaver, Internal Policy Analyst III, Division for Air Quality, 200 Fair Oaks Lane, Frankfort, Kentucky 40601. Phone (502) 564-3999; Fax (502) 564-4666; E-mail susan.weaver@ky.gov.

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Ashland Regional Office 1550 Wolohan Dr. Suite 1 3rd Floor Ashland, KY 41102-8942	Bowling Green Regional Office 1508 Western Ave Bowling Green, KY 42104
Florence Regional Office 8020 Veterans Mem Dr. #110 Florence, KY 41042	Frankfort Regional Office 200 Fair Oaks Ln. Frankfort, KY 40601-1758
Hazard Regional Office 233 Birch St., Suite 2 Hazard, KY 41701-2179	London Regional Office 875 S. Main St. London, KY 40741
Owensboro Regional Office 3032 Alvey Park Dr. Suite 700 Owensboro, KY 42303-2191	Paducah Regional Office 130 Eagle Nest Dr. Paducah, KY 42003-0823
Boone County Clerk 2950 Washington St. Burlington, KY 41005	Campbell County Clerk 1098 Monmouth St. Newport, KY 41071
Kenton County Clerk 303 Court St. Covington, KY 41011	1001604401

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LEGAL NOTICE
American Self Storage will sell items at public auction. The items to be sold are generally described as household goods, boxes, bags, clothing, furniture, appliances, bedding, mattresses, toys, tools, bikes, luggage, trunks, personal effects, equipment, office supplies, fixtures, and business inventories. Auction will take place on 11/26/10 at 9:00 am and continue from location to location in the sequence listed below.
American Self Storage 1775 Eden Park Dr, Hamilton OH 45013 1113 Brett Procaccini 9250 Deer Cross Pkwy Apt. 2B 45236 1118 Todd Bowlin 636 Carlisle Ave. 45013 1329 Brian Howard Krieger 151 Timberhill Dr. Apt. H 45013 2301 Richard Bowling 1348 Carriage Hill Ln. 45013 2421 Marissa Baker 132 Gordon Ave. 45013 3125 Billie Cox Jr. 2109 Fairfax Ave. 45015 3507 Aimee Blundell 1800 Eaton Ave. Apt. 7 45013 4111 David Ream 412 Snowmess Rd. Columbus, OH 43235 4209 Carrie Carr 1033 Eaton Ave. Apt. 4B 45013 American Self Storage 909 Elliott Dr, Middletown, OH 45044 3118 Mikki Crouch 704 The Alameda 45044 7501 Rocky Tate 520 Garfield St. 45044
American Self Storage 800 Cincinnati Ave, Lebanon, OH 45036 1265 Michael Vaughn 780 Harvard Dr. Apt. A 45036 1266 Dani Bolser 1063 Hart Rd. 45036 1267 Jacquelin Grenzebach 7312 Cold Water Ct. Dayton, OH 45459 3117 Kenitra Spidle 3044 Henry Inkster, MI 48141 3410 Lisa Beth Brauninger 31 Pleasant St. 45036 Auction will take place on 11/29/10 at 9:00 am and continue from location to location in the sequence listed below.
American Self Storage 5151 Glencrossing Way, Cincinnati, OH 45238 1305 Jennifer Gooding 2963 Four Towers Dr. 45238 1403 James Massengale III 1013 Fisk Ave. 45205 2505 William Poole 3749 Herbert Ave. 45211 2605 Crystal Riddell 1033 Lockman Ave. 45238 2706 Alexandria Neal 4315 Harding Ave. 45211 3101 Joseph Lee 3643 Werk Rd. 45248 4227 Shawntee Horton 2712 Bello Ct. 45231 4322 Regina Whitehead 2971 West Knoll Ln. 45211 4508 Lisa Love 2677 Montana Ave. 45211 4511 Damion Matthews 960 Grand Ave. Apt. 3 45205 4518 Inez Jackson PO Box 58690 45258 5353 Michael Alter 3415 Michigan Ave. #2 45208 5410 Pauletta Nixon 1197 Rulison Ave. 45238
American Self Storage 8100 Hamilton Ave, Cincinnati, OH 45231 1120 Mooney & Johnson LLC 5401 Bluebird Ln. 45239 1215 Lenay Hardin PO Box 8875 45208 1405 Ronald Willis 1615 W. Kemper Rd. 45240 2133 Mooney & Johnson LLC 5401 Bluebird Ln. 45239 2412 Dion Crockett 1955 Crest Dr. 45240 3330 Reginald Mitchell 1950 Goodman Ave. Apt. 1 45239 3408 Dianne Akins 3984 Fawnhill Ln. 45205 4339 Nikki Smith 3332 Curtis Dr. #303 Hillcrest Heights, MD 20746 4507 Hazel Smith 3332 Curtis Dr. #303 Hillcrest Heights, MD 20746 6015 Daniel Davis 5986 Sunridge Dr. 45224 6017 Daniel Davis 5986 Sunridge Dr. 45224 6018 Daniel Davis 5986 Sunridge Dr. 45224 6107 Anthony Brice 333 Forest Ave. #1 45229 8105 Henry Wallace Jr. 1189 Highcliff Ct. 45224 American Self Storage 101 Glendale-Milford Rd, Cincinnati, OH 45215 1207 Michele Ballew 728 Stout Ave. 45215 4102 Tonya Brown 10144 Love Ct. 45215 4225 Carlotta Simes 338 N Wayne Ave. 45215 5108 Monica Portis 1627 Maryland Ln. 45231 6125 Darrick Wilson 671 Jackson St. 45215 7305 Thomas William 1178 Schmard Ave. 45215 8113 Charmagne Robinson 10690 Deauville Rd. 45240 8314 Alexis Lovett 31 E Lake Shore Dr. Apt. 13 45237 8501 Gary Smith 701 Mulberry St. 45215**American Self Storage 525 W. 35TH St, Covington, KY 41015** 2509 William Luke 26 W 31st St. 41015 3120 Terence Lane 34 Indiana Dr. 41015 3232 Joseph Sherrill 4250 Aspen Dr. #9 41051 3240 Leslie Stewart 17 Indiana Dr. 41015 3324 Kyle Edward Bullock Jr. 2 West 30th St. 41015 3357 Jerry Dority 37 W 32nd St. 41015 4601 Roy Illes 3080 Squiresville Rd. Owenton, KY 40359 4606 Kimberly Balzer 1609 Cumberland Ave. 41011 4607 Robert Murphy 1828 Pearl St. 41014 **American Self Storage 5700 Wooster Pike, Cincinnati, OH 45227** 7212 Trevor Ramsey PO Box #30392 45230 1001604324

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100 homes, ohio

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5 Ac. Grant Co. Partly wooded, city water, 20 min to Florence, $2,000 down, $350 mo. **TRI-STATE LAND CO. (859) 485-1330**

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NEW RICHMOND - 15 acres, beautiful, private, wildlife, rolling woods & creek, water & electric, 15 mins from Downtown, $135,000. 513-553-9750

155 apartments for sale

COLLEGE HILL - $102,000, **FOUR UNIT BRICK**, new wnds, nr bus, nets 11% + gar rental, A. Thompson & Co. 513-385-0227

183 office space for lease

Florence , KY 100 to 2500 sq ft all 1st flr space, nr x-way **Call 859-283-1140**

HAMILTON-- 633 High. Close to downtown. Offices from 500-1100sf. Ample parking. Heat & a/c incl. 513-260-4185

MONTGOMERY--CLASS A Office space 500 sq. ft with a private street entrance and foyer. Private restroom. lg open office area w/small office/ storage room & walk in closet Unlimited parking and walk up entrance wooded & secluded in private prof. office condo complex "Montgomery Station" $650/ mo + shared gas/electric Owner pays $325/month condo assoc. fees & water. Call 543-4600

WESTSIDE Newly remodeled. 4 rms. HVAC incl. Ideal for Attorney, Accountant, or Sales Reps, etc. 513-451-3400

190 investment property

2 Private COUNTRY CLUBS East Loc. & Lrg Mbrshps drive growth, buy 1 or both Bill Sawyer 203-625-0900

200 apartments, furnished

Covington -2 Rm clean, nicely furnished, parking Indry, utils pd, refs $95/wk $150 dep 859-581-3643

MT AUBURN- 1 & 2rm effic, all util furnished, $375 & $395, nr bus line, very nice, 513-381-6690

NORWOOD - Furnished 1 BR, fl 3, incl heat, water & elec, $450/mo. + $450 dep. 513-891-5601

210 hotels motels

$39.99 + tax per night = $159Wk + tax for 1 person Microwave-fridge-phone-cable INDOOR HEATED POOL, Breakfast and BAR I-75 at 2100 Dixie Hwy. ***USA Hotel*** **859-331-1500**

LOOK **Sycamore Total $149/wk** Frig, micro, Indry, cable, **free calls, bus line. 513-761-2575 Cinti, Oh.**

HOT HOT HOT **Red Carpet Inn-Weekly rates. Free movies** /Wi-Fi micro, frig, flat scr TV/DVD, bus, no dep. 513-385-1444

HOT HOT HOT **Tri-County Inn** -Weekly rate. Free movies, Wi-Fi, coffee, micro/frig, DVD Indry, no dep 513-874-3345

210 hotels motels

TRAVELODGE -Newport Wkly rate, Free cont BKF, Micro / frig, wireless. **859-291-4434**

215 apts.-houses to share

HOUSE TO SHARE New finished LL, separate entrance, 2BR, full kitchen & bath, lots of storage, use of pool, great neighborhood, schools, Crescent Springs, Ky. Must see! $750/mo.Incl utils. Call **859-250-6799**

225 apartments, unfurnished

ALL AREAS - effcy, 1, 2, 3, & 4 BR, newly remod, equipt, W/D, gar, some ht/wtr pd, Sec 8 ok, Move-in Special! 513-453-4713

AVONDALE- 1 & 2 BR, heat & water paid, equipped kitchen, Section 8 ok. **513-961-2482**

AVONDALE Virginia Woods Apts, 1, 2 3 & 4 BR, 1st month free with full deposit. Section 8 ready, newly remod, new Indry facility, all utils incl. Call today for specials! **513-344-0097 937-281-0858**

BOND HILL- 1st month RENT FREE. Newly remod lg 2BR, 2nd fl of 2 fam. Wtr pd. $625/mo, 513-417-4932

BOND HILL- 4848 Reading Rd. Nice 1 BR apts $475/mo, all utils incl, deposit special. 937-281-0858

CHEVIOT- 1 BR, $405/mo. Heat/water paid. Newly remodeled. Sorry, no dogs. Also Eff, $325. all utils incl. 513-235-7972

Cheviot- 1 BR Lg dlx Davis Ave. D/W, crpt, balc, ht/wtr, sec. w/caretaker. No Sec 8. $495. Dep. Special w/refs. 513-661-2143

CLIFTON-1, 2 & 3 BR, newly renovated, over 1000 sf ea, $495-$695. Sect 8 ok, free wash/dry. 513-444-7712

CLIFTON 1 & 2BR, hdwd flrs, porch, a/c, eqpt kit, prking. $375-$385. 513-328-1918

HOT HOT HOT **Clifton, Avondale , Bond Hill, Roselawn, Western Hills.** 1 - 2 BR apts, some with utils. paid, **Rent Special call today** $450-$850. **513-961-6906**

COLLEGE HILL- 1 & 2 BR, heat/wtr paid, laundry, parking, a/c, equipt. Sect. 8 ok. 513-615-0640.

COLLEGE HILL - $399 TOTAL MOVE IN 1626 Llanfair section 8/Excel, AC Included. Kroger card giveaway! 513-481-2900

COLLEGE HILL- 5400 Hamilton Ave. **Deposit special!** 1 BR, a/c, carpet, Indry, heat/wtr pd, on-site mgmt, on bus $470, no pets 513-591-1600 851-9887

CORRYVILLE- 1br, carpet, equipped, busline, shopping, $350+G&E 513-281-2500/281-5555

CORRYVILLE-- 1 BR, Coin Indry No Section; No pets. $475 + dep + utils. 513-706-8864

Corryville/ Mt. Auburn- Secure, Clean, Quiet.. 1Br $450.; 2Br $650. ht /wtr incl. 513-861-6588

225 apartments, unfurnished

COVINGTON- Very nice 2 BR, nice hdwd flrs, c/a & ht, lots of upgrades, w/d hkup. $600. 859-428-0159

COVINGTON-- Wallace Woods. 1st flr 1BR 2nd flr 2BR, Equipped kit, W/D, fenced yard, 614-851-9119

DEER PARK 1BR, LR, DR, equipt kit, carpet, A/C, gar, storage, Indry, HEAT PAID $550. 513-314-7220

DELHI- 1br, equipt, crpt, ht pd, Indry, a/c, prkng, nr bus, no pets, $395/mo, 513-505-6539

EASTGATE 1Br, heat, water, sewer, & trash paid. $375 a mo. + dep. 513-528-6929.

Eastgate, Nr--Special $99 dep. 2 BD, C/A, pool, $499. 2 BD $585, Cats ok, ex w/dhkup. 513-753-6191

ELMWOOD PL. / Hasler Units w/crpt, ceiling fan; eqp kit; heat pd. 1BR $400. Sect 8 ok. 513-520-1437, 513-619-7922

ERLANGER, KY 1 & 2BR, avail. Start $500. Sec 8 accept. No deposit req'd 859-727-2256. TDD 7-1-1 . Ashcraft Real Estate Services, Inc EHO

ERLANGER Large 1 & 2 BR's AC, free heat & water. $470-$545. **859-342-5444**

FAIRFIELD -1st Mo Rent Special. Dep starting at $200- lg 1& 2 BR $460-$550 513-858-1444; 349-8899

FAIRFIELD- 2 BR, 2 BA, gas heat, dlx kit w/micwv, W/D hkup, $635 & up + dep, no pets. 513-868-7082

FAIRFIELD. 5467 Southgate Blvd, Apt 4 2 BR, $485. Deposit Special! 513-703-0534

Fairfield Best Landlord! Newer 2 BR condos and townhomes starting at $750. $40 app fee. **Call for specials!** 513-870-9228

FAIRFIELD-FABULOUS, all new 2br, **HEAT & WATER PAID.** a/c, d/w, microwave. Deposit special! $595. 513-829-0007, 513-779-1730

FT THOMAS - 1 BR, 1st flr, A1 cond. Newer eqpt kit., hdwd flrs, C/A, $415/mo + dep + G&E, 859-781-2325

HARTWELL- 1br + den, hdwd flrs, fully equipt, d/w, nwr appl, off st prkng, Indry, wtr pd, no pets, $530/mo, 513-821-3555

Hyde Park - Effic $350/mo 1BR $550/mo. 2BR $750/mo Jackson Advisory Group **513-602-2469**

KENNEDY HTS / NORTHDALE PLACE w/crpt, air, eqpt kit, ht pd. 1 & 2 BR starting at $400, Sect 8 Acpt. 513-520-1437/619-7922

LAKESIDE PARK--10 E. Lakeside Ave. 2 BR, 2nd flr c/a, garage, new eqpt kitchen, DW, microwave, no pets, $595. 859-380-4300

Lincoln Hts -Centennial 1, 2 & 3 BR Apts; 3 & 4 BR Twnhses - Immed. Occup. **1st Month RENT FREE! 513-733-4700** EHO

LUDLOW-- 2BR, 1BA, Lrg 2nd flr. c/a eqpt, w/d hkup, newly updated, no dogs. $600+dep. 859-760-8938

Place your ad today. Call 513-421-6300 or visit www.cincinnati.com

BATAVIA Willowbrook Apts SPECIAL Starting at $550/mo w/1 year lease **& Security Dep. $99** 2br, w/cpt, pool, lake view, blcny plygrd. Section 8 accepted. **513-520-1437 or 513-619-7922**

College Hill Pine Terr. 1BR $405 crpt, air, eqpt kit, includes heat. Sec 8 OK. 513-520-1437/ 513-619-7922

225 apartments, unfurnished

MILFORD 1 MO FREE Large 1 & 2 BR eqpt kit cable ready $395-$495. Nr Rt 28 & I-275. 513-831-6970

MT. AIRY- 1, 2 & 3 BR's, heat & water paid, Indry, prkg, starting $490/mo. Sec. 8 ok. 513-309-2469

MT. AIRY- 2 & 3 BR's, ht & wtr pd balc, Indry, prkg, 1 MO FREE TO QUALIFYING TENANTS. 681-5333

MT. AIRY - Large 1BR & 2BR; ½ block to all stores. **Starting at** $350 - $450. Heat and water paid. ***Let us help you!*** **513-376-7167, 631-0072**

MT. WASHINGTON -1 & 2BR balc, ht/wtr, quiet, $435-$545. No pets 231-8690

N Avondale - NEW renov 2 BR nr XU/ hosp. Rent now-get 1 mo free & flat screen 513-569-9999

N. College Hill North Creek Apts . Lg. fully eqpt, crpt, balc, pool. Heat pd. 1br $480+, 2br 1.5ba $600+ Move in special 521-5800

NORTHSIDE- 1 & 2 BR, heat & water paid, equipped kit, parking, elevator. Sect. 8 app. **513-961-2482**

NORTHSIDE- 1 BR ($380), free ht, 2br ($450), + ht, w/w carp, eqpt kit, a/c, Indry, prkg, water pd. No pets or sec 8, 513-574-6011

NORTHSIDE- 2 BR, heat/ wtr pd, crpt, balc, eqpt kit, Indry, on-site mgr, no pets $580 513-542-0848 851-9887

NORWOOD & E. HYDE PARK- 1 BR Apts, heat/ wtr furn, eqpt kit, a/c, coin-op Indry, (1) parking space, sec bldg w/caretaker, $400-$425/mo, cats ok w/ fee. No dogs. 513-272-0100.

NORWOOD- Lrg efficy, Indry rm in bsmt, heat/wtr/trash pd good location $399. 513-497-1742

PARK HILLS-- Nice 2BR, $495. Includes heat & water. Section 8 ok. Off street parking. 859-912-2351

PLEASANT RIDGE - 1 BR, equipt, carpet, a/c, storage, gar, heat/wtr pd, $525 + dep, 513-841-0331

Pleasant Ridge 1br. **Specials!** Free ht, quiet tree lined st. Conv to shops I-71/75. N/S. 513-631-6611

PRICE HILL-- 1 & 2 BR, w/d hkup, cent. heat & air, prkg, w/w carpet, 513-921-2850

LOOK **Price Hill New 1 & 2 BR "Leaves aren't the only thing falling!" Rent starting @ $400! 513-251-0551 M-F 9-5**

Price Hill --SPACIOUS 1 & 2 BR, Equipt kitchen, **laundry, prkg $300-$400 $130 dep. 513-277-9854**

PRICE HILL Upper- 2 BR, balc, $495. Covedale-1 BR, balc, $400. Heat/water included. 513-451-3191

ROSELAWN-2BR, new crpt, c/a, w/d hkup, $625/mo + sec dep. & utils. Sec 8 okay 513-870-0883

Roselawn Lg updtd 2BR $575/mo coin Indry central air sec 8 ok no dogs 7875 Reading Rd. 227-7280

SILVER GROVE, KY- 1BR's from $540 Effcy's from $340 Utils incl. No pets. 859-240-6210

St. Bernard/ Elmwood Lrg 1Br in 2 family, hdwd flrs, eqpt & eat in kitch, off St pkg, nr 75 & bus, $485 + util, Sec 8 ok, 513-281-1107

Is there any better way to advertise? Call 513-421-6300 to place your ad.

Price Hill /West -- Westridge Apts 2BR's from $500 Air, eqpt kit, ht pd, all units w/crpt. Section 8 OK **513-520-1437 or 513-619-7922**

225 apartments, unfurnished

WALNUT HILLS-- 1BR, fully equipped. New carpet & hardwood floors. A/C. Very nice. 513- 253-8581

WALNUT HILLS-2 BR starts at $450/mo + dep. Sec. bldg, No appl. fee. Voucher OK, on busline, wtr incL. 513-979-5395

WALNUT HILLS 2BR, W/D hkup in kit., Section 8 ok. By appt only, **513-382-2672**

WEST CHESTER - 2br, 2 full ba, equipt, off st prkng, w/d hkup, nr Union Center, $675, 513-615-3435

WEST END-Parktown Co-Op. Studio, 1, 2 & 3 BR Accepting applications M-F, 7:30-4p. 513-721-6080

WESTERN HILLS - clean 2br, 2 family, equipt, off st prkng, $530/mo, 513-659-1341 treicoproperties@gmail.com

WESTERN HILLS - lrg 1br, newly remod, clean & quiet, $385 & up, call for description, 513-481-0339

Westwood -1, 2 BR & Eff **from $295 Section 8 OK**. Lndry. **1st mo $99.** No app fee. 513-826-6851

Westwood-1 & 2 BR, heat & water paid, equipped kitchen. Section 8 ok, a/c. **513-481-2400**

Westwood -2 BR, 4 fam, hdwd, a/c, ceil fans, sec sys, gar, ht pd **$399 Move in Spec. No dep** 553-1195

WESTWOOD-- 2 BR, eqpt kit, w/w carpet, heat/water incl. $540-$565/mo 513-379-2419

THIS OUT!!! **WESTWOOD- $400/MO.** 1BR/1BA. $400 will move you in! Avail now. Vouchers welcome. 513-481-7368

WHITE OAK- 1 BR, heat/water paid, a/c, eqpt kit., off-Str prkng, no pets, $400-$450. 513-385-7407

WINTON PLACE- 1 & 2 BR, $350 & up, water paid, a/c, w/w crpt, eqpt kit, 513-615-0640.

240 condos for rent

Beechmont Nr 275. Luxury 2-3 Br townhm, 2.5 ba, eqpt kit, utility rm, gar, From $850. 513-260-1840

COLERAIN- 2nd flr, 2br, 2 full ba, gar, gas fp, all appl incl w/d, no pets, $760/mo + dep, 513-677-8858

EASTGATE- 1 BR $475 2 BR $650, Ranch, eat-in kit, w/d hookup, walk-out patio, cath clngs 943-3981

EASTGATE, Nr-- 2 BR, 2.5 ba townhome, bsmt., eat-in kit $750. 2 BR, 2.5 BA, 1 car garage, $825. 513-752-2888

Milford--St Rt 28. 2&3 BR 2.5 BA townhome, eat-in kit, w/d hook-up, bsmt, from $795. 513-943-7800

250 houses for rent

COLERAIN- 3 BR, 1.5 BA, Bi level, equipt kit, c/a, FP, 2 car gar, deck, $925 + dep, 513-319-6415

COLLEGE HILL-- 2BR, 1BA, hdwd flrs, fireplace, updated kitchen, 1 car garage, $800. 513-256-8320

COVINGTON- 2, 3 & 4 BR houses, $575, $675 & $775. Plus utilities. Section 8 ok. 859-912-2351.

COVINGTON-- 4 BR, 2 BA, $750 + dep & utils. 2 BR apt $485+dep & utils. . 859-750-0515/859-380-9067

Call 513-421-6300 or visit www.cincinnati.com to place your classified ad.

225 apartments, unfurnished

Westridge Apts 2BR's from $500 Air, eqpt kit, ht pd, all units w/crpt. Section 8 OK **513-520-1437 or 513-619-7922**

KENTUCKY DIVISION FOR AIR QUALITY

NOTICE OF PUBLIC HEARING

TO REVISE KENTUCKY'S STATE IMPLEMENTATION PLAN

DECEMBER 15, 2010

6:00 P.M.

NORTHERN KENTUCKY AREA DEVELOPMENT DISTRICT

22 SPIRAL DRIVE

FLORENCE, KENTUCKY

APPEARANCES:

JOHN GOWINS

SUSAN WEAVER

BY MS. WEAVER: Good evening. It is December 15th, 2010, 6:00 p.m. My name is Susan Weaver with the Kentucky Division for Air Quality, Evaluation Section. As your moderator, I declare this public hearing in session.

The Division asks that everyone attending today's hearing provide all of the information requested on the attendance roster located at the entrance to the conference room.

Today's hearing announcement was mailed to everyone on the Division's current mailing list, to the Regional offices, the Louisville Metro Air Pollution Control District, and located at specified County Clerk's offices. In addition, the notice was published in a newspaper of wide circulation within the Commonwealth.

This is a non-adversarial hearing, so the Division will not respond to comments or questions regarding the proposed actions, and individuals who present testimony will not be questioned by anyone attending this hearing.

A Division representative may, however, ask questions in order to clarify the meaning or intent of a comment.

All comments received in an appropriate format by the close of the comment period will receive equal consideration, and every individual who submits comments will receive a copy of the Statement of Consideration.

Ms. Christina Smith, to my left, is recording today's hearing. Anyone interested in obtaining a copy of the transcript should contact Ms. Smith. Are there any questions?

This hearing is being held to receive comments on a proposed redesignation request and maintenance plan for the Kentucky portion of the Cincinnati-Middletown, Ohio, Kentucky, Indiana 1997 PM2.5 Nonattainment Area.

Since no one has indicated to present testimony at today's hearing, we will pause the hearing record for 10 to 15 minutes to allow for late arrivals and reopen the session. The time is 6:02 p.m.

(Short recess taken.)

BY MS. WEAVER: It is now 6:12 p.m. The

hearing record is reopened. Are there any late arrivals who would like to present testimony? There are none. In the absence of any testimony, this public hearing is now adjourned.

(Hearing concluded at 6:13 p.m.)

COMMONWEALTH OF KENTUCKY)

STATE AT LARGE)

I, CHRISTINA R. SMITH, a Notary Public within and for the Commonwealth of Kentucky at Large, do hereby certify that the foregoing hearing was taken before me at the time and place and for the purpose in the caption stated; that the hearing was reduced to stenotype by me; that the foregoing is a full, true and correct transcript of the said hearing so given; that the appearances were stated in the caption.

WITNESS MY SIGNATURE THIS 20TH day of DECEMBER, 2010.

_____

CHRISTINA R. SMITH
Notary Public
Commonwealth of Kentucky at Large

My Commission Expires: 3-10-12

STATEMENT OF CONSIDERATION

RELATING TO SIP REVISION FOR THE NORTHERN KENTUCKY COUNTIES OF BOONE, CAMPBELL, AND KENTON REDESIGNATION TO ATTAINMENT FOR THE ANNUAL $PM_{2.5}$ STANDARD
Amended After Comments

Environmental and Public Protection Cabinet

Department for Environmental Protection

Division for Air Quality

A public hearing on the State Implementation Plan (SIP) revision for redesignation of Boone, Campbell, and Kenton Counties to attainment for the annual $PM_{2.5}$ standard was held on December 15, 2010, at 6:00 p.m. The hearing was held at the Northern Kentucky Area Development District, 22 Spiral Drive, Florence, Kentucky. Written comments were received during the public comment period.

The following individuals from the Kentucky Environmental and Public Protection Cabinet attended the public hearing and drafted responses to comments received during the public review period.

John Gowins, Environmental Control Supervisor Division for Air Quality

Susan Weaver, Internal Policy Analyst III* Division for Air Quality

* Agency moderator

Response to Comments for the proposed revision to the State Implementation Plan (SIP) to redesignate Boone, Campbell, and Kenton Counties as attainment for the National Ambient Air Quality Standard (NAAQS) for annual $PM_{2.5}$.

1. **Comment:** Please update that maximum available control technology (MACT) controls section on page 22 to reflect the current status of the EPA MACT rule for the industrial boiler and process heater reciprocating internal combustion engines. As written, it may appear that the reductions from these sources where <sic> relied upon with redesignation inventories.
   (Lynorae Benjamin, U.S. EPA)

   Response: The Cabinet acknowledges this comment. The RICE/Industrial Boiler/Process Heater MACT language has been removed from the reductions for attainment section, and added to the section on controls for maintenance on page 22.

2. **Comment:** Appendix D and the VISTAS report may describe the approach used to develop the emissions inventory but the specific data for the Kentucky counties do not

appear to be presented. Please include a listing of the point, area, and nonroad sources by county, pollutant and tons per year for each precursor for the attainment year.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. Kentucky provided the sector pollutants by county, pollutant, and for all years, see Table 25 ($PM_{2.5}$), Table 26 (NO_x), and Table 27 (SO_2).

3. **Comment:** EPA notes that the air quality design value for the monitor with site ID 39-061-0014 in Hamilton, Ohio was 15.04 micrograms per cubic meter ($\mu g/m^3$). There is no margin for increase since the monitor just meets the 15.0 $\mu g/m^3$ standard. For the final rulemaking, please provide additional information regarding the 2010 data to support the maintenance demonstration. If the Area has a violating monitoring <sic> prior to EPA's final action to redesignate the Area, the Area will not be redesignated.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. There is no defined standard for or requirement to address a "margin of increase." The Ohio monitors attained the standard for 2007-2009, and Ohio particulate data thru December 31, 2010 is not yet available. Although the Ohio monitor shows 15.04 $\mu g/m^3$, the projected year inventories show continued maintenance of the standard.

4. **Comment:** If 2008 is the attainment year and emissions for 2008 are overestimated, this will result in an *impermissible extra margin for attainment* in the maintenance plan since the underlying assumption is that the 2008 emissions resulted in attainment. Since the 2008 inventory is projected from the 2005 inventory, it may be the case that the actual emissions in 2008 might have been lower than projected because the projections do not appear to include the impacts of the economic downturn. In particular, please document whether vehicle miles traveled (VMT) estimates used to calculate mobile source emissions for 2008 do not over predict utilization to assure that they were not unduly influenced by the economic downturn.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment and does not agree. The issue regarding economic downturn is outside of the scope of, and not relevant to, the evaluation of this redesignation request. The Travel Demand Model used by OKI has been validated by U.S. EPA as explained in the OKI documentation contained in Appendix E.

5. **Comment:** To further support the maintenance plan, EPA recommends that Kentucky considers including information of the sulfur dioxide (SO_2) emissions in the Ohio and Indiana portions of this nonattainment area regarding permanent and enforceable emissions reductions that are expected to occur, particularly for the electricity generating units (EGUs). Helpful information would include a discussion of the changes in emissions from 2006 through 2008 for those EGUs.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. Emissions information for EGUs in the Ohio and Indiana portions of the nonattainment area is included in the Ohio redesignation request which was included as Appendix H in this redesignation request, and which also may be found at: http://www.epa.ohio.gov/dapc/SIP/annual.aspx.

6. **Comment:** EPA recommends that the maintenance section include a trends analysis of emissions from the EGUs in the comment above that includes 2003-2009 data. All of this data can be easily obtained and analyzed from the EPA Clean Air Markets Division website: http://camddataandmaps.epa.gov/gdm/index.cfm.
(Lynorae Benjamin, U.S. EPA)

   Response: The Cabinet acknowledges this comment, and respectfully declines the recommendation. See response to Comment 5 above, and Kentucky believes a trend analysis for Indiana and Ohio is better served in their redesignation requests.

7. **Comment:** A conceptual description of $PM_{2.5}$ formation would be helpful for the SIP narrative. A discussion on the types or local sources that are in the nonattainment area and affect this formation is needed. Having this discussion on the conditions, causes and variations of $PM_{2.5}$ formation throughout the year is needed in the *Permanent and Enforceable Emission Reductions* section. Without this discussion, the information provided on temperature and precipitation is incomplete and we do not know if conditions occurring in the 2007-2009 attainment period were atypical or typical of conditions leading to $PM_{2.5}$ formation. Referencing the large reports in the appendices are useful, but a more complete and informative discussion to support the Commonwealth's position in needed and must be in the SIP narrative.
(Lynorae Benjamin, U.S. EPA)

   Response: The Cabinet acknowledges this comment. U.S. EPA has published a thorough study on $PM_{2.5}$ formation which can be accessed at: http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_cr_sp.html. This redesignation request was developed and is being submitted due to the area having three years of monitoring data that show attainment of the standard. A protracted discussion regarding atmospheric chemistry and the formation of $PM_{2.5}$ is redundant and negates the usefulness of cited reference material.

8. **Comment:** The reductions from the federal and local measures should be presented on pages 14-21. These pages as presented in the attainment SIP need to be modified and reorganized for a redesignation SIP. There should be two sections that discuss controls: (a) controls that led to attainment (a list of controls, reductions and affected precursors would be ideal); and (b) controls applied to the development of the projection inventories for maintenance.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The narrative has been modified to explain the controls that led to attainment and the controls applied to projection inventories.

9. **Comment:** It is unclear what "overall inventory" is referenced in the Combustion Turbine MACT on page 18. Also, if reductions from this control are being relied upon in the base year inventory.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The narrative has been modified for clarity.

10. **Comment:** Please provide more information on how the reader should interpret the last bullet prior to the *State Control Measures* on page 18 and whether this should be included in the redesignation SIP for $PM_{2.5}$ since volatile organic compounds are not presumed precursor for the $PM_{2.5}$ NAAQS.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The narrative has been deleted.

11. **Comment:** List the regulation number for the reasonably available control measures in section on page 20.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The regulation number is noted in the same section, following paragraph, 401 KAR 50:012 and a link provided. As well, the reader is directed to Appendix G where the regulation text is provided in full.

12. **Comment:** The open burning ban discussion references ozone. From the information provided, it is unclear what pollutant and precursors should be considered for this reference of the regulation as it relates to the $PM_{2.5}$ SIP.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The Cabinet has included language that notes the reductions due to opening burning restrictions include fine particulate as well.

13. **Comment:** Emissions inventory data totals for all emissions source categories for the 2011 and 2021 projection years should be presented in Tables 46, 47, and 48. This is needed to show that projected nonattainment area emission inventories for SO_2, NOx, and $PM_{2.5}$ are expected to decline through 2021.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. Kentucky lists "Projection Totals" by pollutant/emission source category for the entire KY Portion of the nonattainment area Tables 25 ($PM_{2.5}$)-26 (NO_x)-27 (SO_2) for years 2005 through 2021.

14. **Comment:** In the development of the projection inventories, it is unclear how plant shutdowns were addressed in Kentucky or if permits were revoked and what facilities or sources were shut down and by what time.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. There were no permit revocations in this area, and the plant shutdown emissions were negligible.

15. **Comment:** The last sentence before the *Controls Applied* section on page 14 would benefit greatly with a trends analysis of emissions levels from several years prior to and including the attainment years for the three precursor pollutants. Otherwise, it is unclear how emissions levels have changed since the designation of the Area to nonattainment as compared to the changes in ambient air monitoring data.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The data provided in Tables 16 through 49 clearly show a downward trend in emission levels.

16. **Comment:** Also, the last sentence in the controls section on page 14 and other pages throughout the Narrative refers to the modeling and attainment SIP. The redesignation SIP does not involve modeling. We recommend deleting the references to modeling and other revisions throughout the redesignation SIP as appropriate.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The references to photochemical modeling have been deleted.

17. **Comment:** It is unclear why carbon monoxide is written at the bottom of page 30. This appears to be a typographical error. Also, it is unclear why primary point sources of PM 2.5 are not mention <sic> in this paragraph.
(Lynorae Benjamin, U.S. EPA)

Response: The Cabinet acknowledges this comment. The reference to CO has been deleted and a reference to point sources of $PM_{2.5}$ has been added.